FEDERAL REGISTER

Vol. 77 Thursday,
No. 105 May 31, 2012

Pages 31975–32390

OFFICE OF THE FEDERAL REGISTER

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How To Cite This Publication: Use the volume number and the page number. Example: 77 FR 12345.

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

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4. An introduction to the finding aids of the FR/CFR system.

WHY: To provide the public with access to information necessary to research Federal agency regulations which directly affect them. There will be no discussion of specific agency regulations.

WHEN: Tuesday, June 12, 2012
9 a.m.–12:30 p.m.

WHERE: Office of the Federal Register
Conference Room, Suite 700
800 North Capitol Street, NW.
Washington, DC 20002

RESERVATIONS: (202) 741-6008

Printed on recycled paper.

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

Rules and Regulations

Federal Register

Vol. 77, No. 105

Thursday, May 31, 2012

DEPARTMENT OF AGRICULTURE

Food Safety and Inspection Service

9 CFR Parts 416, 417, and 430

[Docket No. FSIS–2010–0023]

Shiga Toxin-Producing Escherichia coli in Certain Raw Beef Products

AGENCY: Food Safety and Inspection Service, USDA.

ACTION: Response to comments on final determination; planned implementation for testing raw beef manufacturing trimmings.

SUMMARY: The Food Safety and Inspection Service (FSIS) is confirming that it will implement routine verification testing for six Shiga toxin-producing *Escherichia coli* (STEC), in addition to *E. coli* O157:H7, in raw beef manufacturing trimmings beginning June 4, 2012. FSIS is also responding to comments on the final determination published September 20, 2011, in the **Federal Register** regarding the June 4, 2012, implementation of STEC sampling and related issues.

DATES: Beginning June 4, 2012, FSIS will implement routine verification testing for the six additional STECs discussed in this document (O26, O45, O103, O111, O121, and O145), in raw beef manufacturing trimmings (domestic or imported) derived from cattle slaughtered on or after June 4, 2012. To allow industry time to implement any appropriate changes in food safety systems, including control procedures in their processes, FSIS will generally not regard raw, non-intact beef products or the components of these products found to have these pathogens as adulterated until June 4, 2012. FSIS will announce in a future **Federal Register** document the date it intends to implement routine verification testing for the specified STECs in additional raw beef products tested by FSIS for *E. coli* O157:H7, including ground beef.

FOR FURTHER INFORMATION CONTACT: Rachel Edelstein, Acting Assistant Administrator, Office of Policy and Program Development, Food Safety and Inspection Service, U.S. Department of Agriculture, (202) 205–0495.

SUPPLEMENTARY INFORMATION:

Background

On September 20, 2011, FSIS published a document in the **Federal Register** announcing its determination that raw, non-intact beef products, or raw, intact beef products that are intended for use in raw non-intact product, that are contaminated with Shiga toxin-producing *Escherichia coli* (STEC) O26, O45, O103, O111, O121, and O145 are adulterated within the meaning of 21 U.S.C. 601(m)(1) (76 FR 58157; Sep. 20, 2011). The products are adulterated because they contain a poisonous or deleterious substance that may render them injurious to health. FSIS stated that raw, non-intact beef products that are contaminated with these STEC are also unhealthful and unwholesome (under 21 U.S.C. 601(m)(1) and (m)(3)) (76 FR 58157 at 76 FR 58159). FSIS also considers intact cuts that are contaminated with these pathogens to be adulterated, unhealthful, and unfit for human food if they are to be further processed into raw, non-intact products before being distributed for consumption (76 FR 58157 at 76 FR 58159).

FSIS announced that it intended to implement sampling and testing for the six non-O157 STEC, as it already does for *E. coli* O157:H7. The Agency said that it would begin this verification and testing program on March 5, 2012. The Agency noted that it would initially sample only raw beef manufacturing trimmings and other ground beef components for the six non-O157 STEC, but that it would consider other products, including raw ground beef contaminated with these STEC, to be adulterated (at 76 FR 58160). The Agency asked for comments on its plans for implementing the program (at 76 FR 58157, 58164).

In addition, FSIS asked for comments on Agency plans for a baseline survey of the prevalence of the specified STEC in raw beef products, whether to hold technical or other public meetings, various cost estimates, the type of outreach and information that would be most useful to establishments preparing for implementation by the Agency of its sampling and verification testing program, and information that foreign governments might need to address inspection equivalency or implementation concerns.

FSIS extended the public comment period from November 21, 2011, to December 21, 2011, and held a public meeting by teleconference on December 1, 2011. (76 FR 72331; Nov. 23, 2011).

In response to comments received from industry, FSIS issued a **Federal Register** notice (77 FR 9888; Feb. 21, 2012) in which FSIS moved the implementation date to June 4, 2012, for routine verification activities, including testing, for the six specified STEC in raw beef manufacturing trimmings derived from cattle slaughtered on or after June 4, 2012. To allow establishments time to implement appropriate changes in their food safety systems, including changes in process control procedures, FSIS will generally not treat as adulterated raw beef products found to have these pathogens until June 4, 2012. Additionally, FSIS will begin conducting for-cause food safety assessments (FSAs) in response to FSIS positive non-O157 STEC results approximately 90 days after FSIS implements non-O157 STEC sampling and testing in beef manufacturing trimmings. This 90-day period will provide establishments sufficient time to make any necessary changes to their food safety systems.

When FSIS laboratories analyze the samples, FSIS anticipates that there will be some samples that will, in the first stage of the FSIS screen test, test positive for Shiga toxin gene (*stx*) and for the intimin gene (*eae*) but screen negative for all the target O-groups (O26, O45, O103, O111, O121, and O145). Such samples will be referred to the USDA-Agricultural Research Service (ARS) for further microbiological analysis to determine whether they are positive for other target O-groups. FSIS expects to collect and analyze these screen results from its verification tests for at least the first year of testing. FSIS will not consider the product associated with non-confirmed results to be adulterated. FSIS believes that the information on these screen results will be useful to establishments in enhancing the preventive controls in their food safety systems and believes that establishments will benefit from knowing whether they have screen-positive but not confirmed sample results for *E. coli* O157:H7 or the specified non-O157 STECs. Therefore, FSIS is contemplating providing individual establishments with this information every quarter. In addition, FSIS expects to regularly make aggregate information known to stakeholders in order for stakeholders to be aware of and to consider the relevance of the information.

FSIS, as a public health regulatory agency, has adopted a preventive, risk mitigation strategy that takes into consideration the fact that the specified STECs are adulterants of certain raw beef products. In support of this strategy, FSIS has finalized its risk profile to reflect comments, the results in a recent article on thermal resistance of STEC-inoculated non-intact beef steaks with strains of *E. coli* O157:H7 and non-O157 STEC (a pooled composite of STEC serogroups O45, O103, O111, O121, and O145) by USDA–ARS (Luchansky et al., 2012), and information from articles on how much more common non-O157 STEC infections are compared to *E. coli* O157:H7 infections (Blanco et al., 2004; Elliott et al., 2001; Nielsen et al., 2006; Vally et al., 2012). The final risk profile is available on the FSIS Web site at *http://www.fsis.usda.gov/Science/Risk_Assessments/index.asp*

In the September 20, 2011, **Federal Register**, FSIS also announced the availability of, and requested comments on, the guidance document, *Validation Guidance for Pathogen Detection Test Kits.* FSIS explained that the Agency prepared this guidance for the validation of test kits for the detection of pathogens, including both *E. coli* O157:H7 and non-O157 STEC. FSIS encouraged organizations that design or conduct validation studies to avail themselves of this guidance document in meeting the pertinent regulatory requirements. FSIS received numerous comments on this document, will update it as necessary in response to comments, and will announce the availability of the updated guidance document when it is ready.

I. Implementation plan

In finalizing the plan for implementing its verification activities, including the sampling and testing program for the specified STECs, FSIS considered all comments submitted in response to the September 2011 final determination, as well as comments provided at the December 1 teleconference, and is clarifying certain aspects of the implementation of the verification activities.

FSIS will issue a **Federal Register** notice announcing when FSIS will begin routine sampling and testing for the seven STECs of all raw beef products subject to Agency *E. coli* O157:H7 sampling and testing, from both domestic and international sources, regardless of the slaughter date of cattle from which the product is derived. When expanded testing begins, mixtures of raw beef derived from cattle slaughtered either before or after June 4, 2012, whether the production lot contains raw beef manufacturing trimmings, other raw ground beef components, bench trim, or ground beef, will be subject to testing for the seven specified STECs.

The Agency is updating the economic analysis published in the September 20, 2011, **Federal Register** notice in response to public comments received. To respond more thoroughly to the comments, FSIS will incorporate any additional data on establishment and Agency testing for the specified STECs that may be available upon FSIS's implementation of routine testing for non-O157 STECs in beef manufacturing trimmings. As indicated in the September 20 notice (at 76 FR 58163), the Agency will update and revise the September 20, 2011, economic analysis, will respond to comments received on the earlier analysis, and will assess the economic effects of testing for the specified STECs on raw beef manufacturing trimmings, other raw ground beef components, and ground beef. When the Agency completes the updated analysis, FSIS will announce its availability and request comments on the analysis. The Agency will then assess comments and make any necessary changes before finalizing the economic analysis and before expanding FSIS testing to include other raw ground beef components and ground product.

II. Comments and Responses

FSIS received approximately 34 comments in response to the September 2011 notice. Comments received from consumer groups supported the implementation of the final determination that six additional STEC serotypes are considered adulterants in non-intact raw beef products and intact beef products used to produce such products and encouraged FSIS to resist delaying the implementation date. Several consumer advocacy groups, citing the incidence of foodborne disease caused by these organisms, expressed support for FSIS's final determination. Comments submitted by industry, trade associations, and foreign countries expressed concerns about the final determination and implementation of the verification sampling and testing program.

Following is a discussion of comments that requested more information or clarification regarding the verification testing program that will begin on June 4, 2012.

Delay Implementation

Comment: Many commenters requested a delay of the implementation date for the testing of the specified STECs for various reasons, including their view that FSIS needs to conduct a baseline of non-O157 STECs on beef products, needs to wait until commercially available test kits for these organisms become available and can be validated, needs to hold a technical meeting, and needs to conduct a risk assessment.

Response: FSIS has concluded that a baseline is neither necessary nor warranted before implementation of the FSIS verification sampling and testing program. These organisms are present in beef products in the United States; the evidence for this is presented in the risk profile. FSIS considers the data on non-O157 STECs obtained by the Agricultural Research Service (ARS) at a limited number of slaughter establishments to be evidence that the pathogens should be considered adulterants and are capable of causing illness. FSIS also considered data collected by the person who petitioned the Agency to declare these pathogens to be adulterants in a limited geographical retail area. The Agency has concluded, on the basis of information in a report from the Centers for Disease Control and Prevention (CDC), that these organisms pose a significant public health burden in the United States.[1] FSIS and the CDC believe that there are more unreported and unconfirmed illnesses associated with the specified non-O157 STECs than with *E. coli* O157:H7.

Nonetheless, in 2013 FSIS intends to conduct the carcass baseline survey discussed in the September 20, 2011 **Federal Register** notice. This microbiological survey will analyze samples from carcasses for the presence of the pathogens *E. coli* O157:H7 and the specified STECs, *Salmonella,* and indicator bacteria (generic *E. coli,* coliforms, and Enterobacteriaceae). This baseline will be designed to identify the type, level, and frequency of

[1] Scallan E, Hoekstra RM, Angulo FJ, Tauxe RV, Widdowson M-A, Roy SL, Jones JL, and Griffin PM. 2011. Foodborne illness acquired in the United States—major pathogens. Emerg Infect Dis.

contamination of carcasses immediately after hide removal but before decontamination treatments and evisceration. When the baseline study is being developed, FSIS will share the study design with stakeholders.

Regarding a baseline for raw beef manufacturing trimmings, other raw ground beef components, and ground beef, FSIS is assessing its current verification testing programs to see how those programs can be modified to yield on-going baseline information and obviate the need for stand-alone baseline studies.

At this time, FSIS is not planning to host a technical meeting relating to non-O157 STEC. Commenters did not identify any specific need for a technical meeting. If there is evidence that a technical meeting would be helpful to industry, FSIS will, of course, reconsider this issue.

Screening and confirmation methods for non-O157 STEC are available to industry. In addition, reagents are commercially available to those companies planning to use the FSIS method. Some establishments have been testing for non-O157 STECs for a year or more.

Several companies have submitted test kits to detect at least the six specified STEC O-groups for review by validation bodies. Using the FSIS compliance guidelines related to validating test kits, FSIS has reviewed validation data from test kits and issued no-objection-letters (NOLs) to several manufacturers. The NOLs provide establishments with supporting documentation regarding the reliability of verification testing results. Confirmation testing is available to industry through commercial reagents.

Regarding the contention that a risk assessment is needed, the Agency has assessed scientific data from several fields on the risk posed by non-O157 STECs and determined that these pathogens are adulterants under the FMIA. To make this determination, the Agency prepared a risk profile, which has been independently peer reviewed in accordance with Office of Management and Budget (OMB) guidelines. Both, the CDC and the Food and Drug Administration (FDA)/Center for Food Safety and Applied Nutrition reviewed the document and provided input on FSIS' approach. The risk profile lays out all available information on the public health concerns posed by these organisms and supports the adulteration determination regarding these *E. coli* serogroups.

FSIS Sampling Plan

Comment: Several commenters stated that FSIS has not adequately justified the initiation of the non-O157 STEC sampling program, given that non-O157 STECs are found at levels comparable to *E. coli* O157:H7, and infection from the non-O157 STEC tends to be less severe than that from *E. coli* O157:H7. One commenter questioned whether FSIS's testing program will be adequate for determining process control and stated that FSIS's end-product testing will have no impact other than to consume resources that could be better spent on food safety research.

Response: The FSIS verification testing program is intended to assess whether the industry, collectively, is controlling for the presence of a designated food safety hazard in products regulated by FSIS. Adding the six non-O157 STECs to the group of pathogens for which FSIS tests will help in improving food safety. The purpose of the new testing program for non-O157 STECs is to verify that establishments producing raw beef products have adequately addressed these pathogens.

FSIS acknowledges that the best approach to reducing STEC contamination lies not in comprehensive end-product testing but in the development and implementation of science-based preventive controls, with end-product testing to verify process control. FSIS's non-O157 STEC testing program will improve food safety because FSIS anticipates that establishments may voluntarily make changes to their food safety systems in response to the new testing. For example, establishments may initiate a testing program for non-O157 STECs or may add new interventions to address pathogens. FSIS is aware that some companies have added new bacteriophage interventions to address non-O157 STEC. FSIS is not requiring such changes but anticipates establishments may make these types of changes in response to the testing.

The non-O157 STECs may cause illnesses of varying severity. Though limited data are available on dose-response, there is evidence that the infectious doses of the pathogens are relatively low. Hence, their potential to cause illness is relatively high. Although there is variability in virulence severity of non-O157 STECs, the six specified non-O157 STEC organisms can cause severe foodborne illness requiring hospitalization. Numerous illnesses in the United States have resulted from all six of the non-O157 STECs. CDC data show that the six STEC organisms for which FSIS will be testing are known to cause more than 80 percent of human illnesses attributed to non-O157 STEC.

The number of illnesses and deaths caused by non-O157 STECs and associated with beef consumption or a beef source is likely to decline if establishments voluntarily make changes to their food safety system that result in greater public health protection. Also, FSIS's current testing for *E. coli* O157:H7 may not detect other STECs that may be present in the product.

Comment: One industry commenter asked whether FSIS intends to collect two samples for N–60 sampling, and if so, would *E. coli* O157:H7 testing be performed on one sample and non-O157 STEC testing on the other sample. Another commenter noted that FSIS does not specify the number of samples it intends to collect in the sampling plan.

Response: FSIS inspection personnel will collect one N–60 sample (in multiple containers) that will be tested for all the STECs, including *E. coli* O157:H7. Eventually, FSIS will analyze all the raw beef samples collected for both *E. coli* O157:H7 and non-O157 STEC.

Comment: Several commenters stated that FSIS's sampling plan should be designed to estimate prevalence of the STEC pathogens in raw beef products.

Response: FSIS verification testing programs are not designed at this time to assess statistically-based national prevalence for select organisms. FSIS verification testing assesses establishment control of a food safety hazard in products regulated by FSIS. The number of tests FSIS will annually conduct for non-O157 STECs will exceed the number typically analyzed in a structured baseline. Although FSIS's testing will not provide a true prevalence estimate upon implementation, it will provide helpful information about whether establishments' food safety systems adequately address food safety.

Comment: One commenter asked how FSIS intends to increase its collection rates for its beef manufacturing trimmings testing program.

Response: The Agency has a number of different initiatives underway to increase its collection rates for the beef manufacturing trimmings testing programs. Importantly, the new Public Health Information System (PHIS), which is now implemented nationwide, can schedule samples for laboratory analysis. PHIS does so in a way that ensures that requests are sent only to establishments whose profiles (information on establishment characteristics) indicate that they are producing the targeted product at the time of sample scheduling. In addition, if an establishment no longer makes the product, PHIS allows inspection program personnel to modify the establishment profile (information on establishment characteristics) to reflect this change so that future samples are not scheduled for that establishment.

FSIS Testing Method

Comment: One association questioned whether the FSIS method published in the Microbiology Laboratory Guidebook (MLG) on November 4, 2011, was appropriately peer-reviewed. Commenters questioned whether industry is required to test for non-O157 STECs, and whether industry would be required to use the FSIS method.

Response: Initial results from the method-development phase were published in a peer-reviewed journal with ARS and FSIS authors.[2] The MLG method was validated and then verified for internal use by FSIS Laboratory Services. In addition, when designing the screening and confirmatory strategy for the regulatory test, FSIS sought input from the CDC, ARS, and the FDA and worked closely with ARS in transferring the method to use in the FSIS laboratories.

FSIS is not requiring STEC testing by industry, nor will it establish a requirement for the FSIS testing methodology to be used. Also, foreign government central competent authorities and foreign establishments can determine what testing to conduct and can use any test that they determine is sufficient to identify the presence of the specified STECs. As with the domestic beef establishments, foreign government central competent authorities and foreign establishments are expected to ensure that raw beef product is controlled for the presence of the specified non-O157 STECs.

Comment: One commenter asked whether the most-probable-number (MPN) enumeration was included in the FSIS method.

Response: No, the FSIS MLG method 5B.01 as described does not include an MPN method for enumerating non-O157 STEC in positive samples.

Comment: Several commenters questioned the Agency's statement referring to expected establishment actions following *stx*- or *eae*-positive first-stage screen results (at 76 FR 58161, col. 3): ''A first-stage screen positive (*stx* and *eae*) is evidence of the presence of Shiga toxin and intimin and may indicate that an establishment is not adequately addressing hazards reasonably likely to occur. Establishments should reassess their HACCP plans, Sanitation Standard Operating Procedures, or other prerequisite programs on the basis of this evidence.'' Commenters were concerned that an establishment would be required to reassess its Hazard Analysis and Critical Control Point (HACCP) plan after such results.

Response: The Agency regrets any confusion that this statement created. The first- and second-stage screening steps of the FSIS method are performed concurrently, not sequentially. Establishments are not required to take corrective actions or reassess their HACCP plans in response to positive FSIS screen results. However, establishments would be required to take corrective actions or reassess their HACCP plans in response to FSIS confirmed positive results for the specified non-O157 STEC.

Some establishments may use the FSIS laboratory method or another method that could indicate the presence of *stx* or *eae* genes or the presence of one of the relevant ''O'' subgroups. Such screen-positive results indicate the presence of an organism capable of causing illness. If an establishment does not perform additional testing, it should treat lots that test positive in screen tests as positive. Similarly, FSIS will consider those results positive for non-O157 STEC if not confirmed negative. This is consistent with how FSIS regards positive *E. coli* O157:H7 screen results.

Therefore, if an establishment finds product positive for any of the specified non-O157 STECs in screen testing, does not confirm the finding as negative, and has not addressed the hazard in its HACCP system, the establishment would be required to take corrective actions, including reassessing its HACCP plan (9 CFR 417.3).

Comment: Commenters stated that a large number of samples will screen positive using the screening method described in MLG 5B.01. Commenters also stated that the isolation and confirmation process takes a long time to complete and that producers cannot hold fresh product pending the completion of isolation and confirmation described in the MLG 5B.01.

Response: FSIS does not agree with these assertions. Based on available data, FSIS estimates that 2 percent of raw beef samples tested using the FSIS method would test positive for non-O157 STEC in screen tests, with a significantly lower percentage being confirmed. This is comparable to what FSIS has found with the FSIS screening method for *E. coli* O157:H7. The amount of time to obtain a confirmation result from the new FSIS non-O157 STEC method is the same as that for the current *E. coli* O157:H7 method. The reagents for the FSIS test method, including the confirmation method, are commercially available to industry.

Establishment Testing

Comment: One commenter asked whether, if an establishment only tested for *stx* (Shiga toxin) and *eae* (intimin) genes using a polymerase-chain-reaction (PCR) screening test, and the sample tested negative, FSIS would accept this result as negative for *E. coli* O157:H7 and the specified non-O157 STECs.

Response: FSIS would accept as negative for *E. coli* O157:H7 and the specified non-O157 STECs a sample that tests negative for *eae* and *stx* on a screening test performed by an establishment.

FSIS recognizes that industry uses non-culture methods that detect alternative target analytes for *E. coli* O157:H7 including, but not limited to, *eae* and *stx.* An establishment may increase the likelihood of detecting all hypothetical strains and low-levels of contamination with these pathogens in a variety of ways, including but not limited to using a test method that is also used by a regulatory body, or that is validated and certified by an independent body (e.g., AOAC International, the French Association for Standardization (AFNOR), the European organization for the validation and certification of alternative methods for the microbiological analysis of food and beverages (MicroVal), or the Nordic system for validation of alternative microbiological methods (NordVal)). An establishment may also opt to use a test method for detecting the specified STECs that is subjected to a robust validation using the FSIS cultural method as a reference. In this case, a test kit manufacturer may choose to ask the Agency through AskFSIS to review the method. If the method is found to be adequate, FSIS will issue a NOL to the test kit manufacturer for filing with the establishment.

Comment: A law firm representing beef industry clients asked whether, during the transition period (until June 4, 2012), when establishments are ''beta testing'' STEC analytical methods and possibly refining their food safety

[2] Fratamico, P.M., Bagi, L.K., Cray Jr, W.C., Narang, N., Medina, M.B., Liu, Y. Detection by multiplex real-time PCR assays and isolation of Shiga toxin-producing *Escherichia coli* serogroups O26, O45, O103, O111, O121, and O145 in ground beef. Foodborne Pathogens and Disease 2011; 8(5):601–7.

system, a stage-one positive test result would be considered positive.

Response: No, after the June 4 implementation date for the FSIS verification testing program, positive ''beta tests'' will not be considered by FSIS to be conclusive evidence that one or more specified STECs is present in the sample. However, if product from the establishment is associated with a non-O157 STEC outbreak, FSIS will take steps to ensure that associated product is removed from commerce and will expect the establishment to take corrective actions, including reassessment of its HACCP plan, if necessary, to prevent a recurrence of this food safety hazard.

FSIS encourages establishments to maintain records from ''beta testing'' as part of the documentation of the development of their food safety systems. Establishments may use these records to show the controls they have in place and the disposition of their products.

Comment: An industry commenter asked where industry can obtain the non-O157 STEC strains for testing purposes.

Response: Non-O157 STEC strains may be obtained from public collections, including the STEC collection at Michigan State University, the *E. coli* Center at Penn State University, the American Type Culture Collection in Manassas, Virginia, and at other locations.

Comment: One trade association asked whether *E. coli* O157:H7 could be used as both an indicator and an index organism for non-O157 STEC in beef production.

Response: If source materials are sampled at a sufficiently high frequency and in a consistent manner, test results for the presence of *E. coli* O157:H7 or non-O157 STEC can serve as indicators of process control during beef production. In fact, in data [3] from inspection personnel at the top 33 (by volume) beef slaughter establishments, 60 percent of establishments had defined high-event periods when the establishments could discern subtle changes in the percent-positive screening test results as evidence of a process out of control. FSIS believes that the screening tests that the industry has been using are capable of indicating the presence of more than just *E. coli* O157:H7.

Because both *E. coli* O157:H7 and non-O157 STECs occur in raw beef at low levels and at low prevalence, however, positive tests for these pathogens are not likely to be highly correlated. Therefore, neither *E. coli* O157:H7 nor non-O157 STEC are expected to provide reliable index measurements. An index organism is one whose concentration or frequency correlates with the concentration or frequency of another organism.

FSIS-Recommended Cooking Temperatures

Comment: One commenter stated that if STECs can survive ''ordinary'' or ''typical'' cooking, FSIS should reconsider its cooking temperature recommendations. Another commenter stated that there is insufficient data regarding heat tolerance of non-O157 STECs.

Response: FSIS's temperature recommendation for consumers to cook ground beef to 160 degrees Fahrenheit is adequate to achieve a safe product. There is no reason to believe that a higher temperature is necessary (*http://www.fsis.usda.gov/Fact_Sheets/Ground_Beef_and_Food_Safety/index.asp*). However, FSIS is well aware that some consumers ordinarily or typically do not cook ground beef to 160 degrees Fahrenheit, in spite of the extensive outreach and education efforts conducted by the Agency and its public health partners to change behaviors.[4] In addition, FSIS believes that most consumers do not use a thermometer to confirm the end-point temperature for safety. Consequently, the handling and preparation practices of many consumers are not ''ordinarily'' or ''typically'' capable of rendering the cooked ground beef safe without further risk mitigation.

The September 20, 2011, **Federal Register** notice cited the August 2010 STEC O26 outbreak and other evidence (at 76 FR 58159—Luchansky et al., published in 74 *J. Food Prot.* (2011)7:1054–1064) that demonstrates that the strain survives ''typical'' cooking employed by some consumers, and that further risk mitigation was necessary. Researchers at USDA–ARS examined the effect of various cooking temperatures on strains of five serogroups (O45, O103, O111, O121, and O145) and *E. coli* O157:H7 inoculated into beef steaks that were then tenderized. Results show that the non-O157 STECs exhibited thermal inactivation similar to that for *E. coli* O157:H7.[5] In another study (Duffy et al., 2006), STEC O26 also showed similar thermal tolerance to *E. coli* O157:H7.

Equivalency and Implementation Concerns of Foreign Governments

Comment: Several commenters noted that the September 20, 2011, **Federal Register** notice states (at 76 FR 58161, col. 1–2): ''For imported products tested at port of entry, if the product tests positive at the second stage and has not been held at the import establishment, it will be subject to recall. If the product has been held, the product will be refused entry. As always, product subsequently presented for import inspection from the same foreign country and establishment will be held at the official import establishment pending results.'' These commenters asked whether FSIS intended to treat imported product tested for non-O157 STEC differently from such product tested for *E. coli* O157:H7.

Several trade associations and foreign governments addressed various topics relating to the treatment of imported products at port of entry, the equivalency of foreign inspection systems, and United States obligations under World Trade Organization agreements. Governments and industry trade groups expressed concern that the new non-O157 STEC policy may violate the United States' obligations under the Agreement on Sanitary and Phytosanitary (SPS) Measures. Finally, governments and trade associations questioned the adequacy of the FSIS risk profile with respect to how it addresses characteristics of non-O157 STEC.

Response: Consistent with FSIS's procedures for testing for *E. coli* O157:H7 in imported product, if a product offered for import tests positive at port of entry for non-O157 STEC in the screen test and has not been held at the import establishment, it will not be subject to recall. However, if the product is still at the import establishment, FSIS will retain the product until it is confirmed negative.

If the product is confirmed positive and has been held by the establishment or retained by FSIS at the import establishment, FSIS will refuse entry of the product. If the confirmed-positive product has not been held at the import

[3] To help develop the operational criteria for industry to use to identify high-event periods and for Enforcement, Investigations, and Analysis Officers to consider when conducting traceback procedures, FSIS examined industry data collected by FSIS inspection personnel from the top 33 slaughter establishments, representing 80 percent of industry production volume (number of cattle slaughtered).

[4] Ecosure. 2007 U.S. Cold Temperature Evaluation. October 15, 2008.

[5] Luchansky J.B., Shoyer B.A., Call J., Schlosser W., Shaw W., Bauer N., Latimer H., Porto-Fett A. 2012. Fate of Shiga-toxin producing O157:H7 and non-O157:H7 *Escherichia coli* cells within blade-tenderized beef steaks after cooking on a commercial open-flame gas grill. Journal of Food Protection. 75:62–70.

establishment, FSIS will request that the importer of record recall the product.

FSIS has notified its trading partners about the new non-O157 STEC testing policy. The Agency has committed to video conferencing and teleconferencing exchanges to assist foreign governments in understanding the policy and how it applies to them. The Agency expects countries that export products to the United States to address non-O157 STEC under existing agreements and to prevent contamination of their raw beef products with these adulterants. Foreign countries may use any method that will ensure, with reasonable confidence, that products that they export to the United States will not be contaminated with detectable non-O157 STEC. Because of the nature of non-O157 STECs, FSIS would not exclude any country importing product subject to testing from non-O157 STEC verification testing by FSIS.

Finally, the Agency has assessed scientific data from several fields on the risk posed by non-O157 STECs and determined that these pathogens are adulterants under the FMIA. To make this determination, the Agency prepared a risk profile, which has been independently peer-reviewed in accordance with Office of Management and Budget (OMB) guidelines. Both CDC and FDA reviewed the document and supported FSIS's approach.

The risk profile, in its final version, incorporates CDC data that show that the organisms for which FSIS will be testing are known to cause more than 80 percent of human illnesses attributable to non-O157 STECs in the United States.

In addition, FSIS refined the risk profile substantially in response to comments that were received during peer review. Accordingly, the risk profile represents the best characterization of the science associated with the risk from the specified non-O157 STECs.

One commenter raised a concern about the attribution of a non-O157 STEC outbreak in 2007 to a beef product. This outbreak was included in the risk profile.

CDC has information, including a May 21, 2010, memo, stating that, ''The preliminary data in the table were obtained primarily from reports voluntarily made by state health departments to CDC. In 2010, we supplemented NORS [National Outbreak Reporting System] data from the on non-O157 STEC outbreaks by contacting state and federal health agencies, by reviewing the scientific literature, and by other methods.'' The data reported in the memo may be more complete than the data submitted by the reporting agency to the Foodborne Disease Outbreak Surveillance System (FDOSS), which is a component of NORS. In the memo, CDC listed the confirmed or suspected vehicle for this outbreak as ground beef. This was based on a posting on the North Dakota State Health Department Web site.

FSIS recognizes that the availability of attribution data for the non-O157 STECs is partially a function of the number of clinical laboratories that test for the pathogens, as well as of the robustness of epidemiological investigations. In this case, however, the only available information suggests that the non-O157 STEC outbreak may have been linked to a beef product.

Summary of Changes and Clarifications Made in Response to Comments

As noted earlier in this document, in response to comments on the September 20, 2011, notice (76 FR 58157), FSIS extended the public comment period from November 21, 2011, to December 21, 2011 (76 FR 72331; Nov. 23, 2011). Also in response to public comments, FSIS held a technical meeting December 1, 2011, to solicit additional comments. FSIS later moved the implementation date of the non-O157 STEC verification policy for beef manufacturing trimmings to June 4, 2012 (77 FR 9888; Feb. 21, 2012). The purpose of the delay in implementation was to allow the regulated establishments time to effect any necessary changes in their food safety systems, including process control procedures, and to allow time for improvements in testing methods.

In addition, in response to comments, the Agency made available to foreign governments reagents used in the FSIS method. To allay other concerns of foreign governments, the Agency affirmed that it would treat incoming foreign product in the same way that it treats such product FSIS tests for *E. coli* O157:H7.

On the matter of using indicator organisms, FSIS has affirmed that testing of source materials of raw, non-intact beef products for STEC to verify process controls can be effective if the materials are sampled at sufficiently high frequencies. However, FSIS has clarified that *E. coli* O157:H7 is not an index organism for non-O157 STEC.

In response to questions, FSIS has clarified that establishments are not required to take corrective actions in response to FSIS screen positive results. However, FSIS has also clarified that if establishments find product positive for non-O157 STECs in their screen tests and do not conduct further testing to confirm that the product is negative, FSIS will consider the product positive for non-O157 STECs, just as FSIS considers product that screens positive for *E. coli* O157:H7 to be positive if an establishment does not conduct further testing.

Finally, the Agency has finalized the risk profile on the non-O157 STECs and has incorporated relevant information conveyed by commenters.

Executive Order 13175

The policy discussed in this notice does not have Tribal Implications that preempt Tribal Law.

USDA Nondiscrimination Statement

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Additional Public Notification

Public awareness of all segments of rulemaking and policy development is important. Consequently, FSIS will announce it on-line through the FSIS Web page located at—*http://www.fsis.usda.gov/regulations_&_policies/Interim_&_Final_Rules/index.asp.*

FSIS also will 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, and other types of information that could affect or would be of interest to our constituents and stakeholders. The Update is communicated via Listserv, a free email subscription service consisting of industry, trade, and farm groups, consumer interest groups, allied health professionals, scientific professionals, and other individuals who have requested to be included. The Update also is available on the FSIS Web page. Through Listserv and the Web page, FSIS is able to provide information to a much broader, more diverse audience. In addition, FSIS offers an email 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_&_Events/Email_Subscription/.* Options range from recalls, export information, regulations, directives, and notices. Customers can add or delete subscriptions themselves, and have the option to password-protect their accounts.

Done at Washington, DC, May 25, 2012.

Alfred V. Almanza,

Administrator.

[FR Doc. 2012–13283 Filed 5–29–12; 4:15 pm]

BILLING CODE 3410–DM–P

NATIONAL CREDIT UNION ADMINISTRATION

12 CFR Parts 701, 703, 713, 721, 723, and 742

RIN 3133–AD98

Eligible Obligations, Charitable Contributions, Nonmember Deposits, Fixed Assets, Investments, Fidelity Bonds, Incidental Powers, Member Business Loans, and Regulatory Flexibility Program

AGENCY: National Credit Union Administration (NCUA).

ACTION: Final rule and interim final rule with comment period.

SUMMARY: NCUA is removing certain regulations and eliminating the Regulatory Flexibility Program (RegFlex) to provide regulatory relief to federal credit unions. NCUA is also removing or amending related rules to ease compliance burden while retaining certain safety and soundness standards. Those rules pertain to eligible obligations, charitable contributions, nonmember deposits, fixed assets, investments, incidental powers, and member business loans. In addition, NCUA is issuing an interim final rule with a request for comment to amend a provision in the fidelity bond rule to remove references to RegFlex.

DATES: *Effective dates:* The final rule, as well as the interim final rule pertaining to the revisions in the fidelity bond rule, § 713.6, will go into effect on July 2, 2012.

Comment date: We will consider comments on the interim final rule portion (the fidelity bond rule, § 713.6), as discussed in section IV of the preamble of this rulemaking. Send your comments to reach us on or before July 30, 2012. We may not consider comments received after the above date in making any decision whether to amend the interim final rule.

ADDRESSES: In commenting on the interim final rule, you may submit comments by any of the following methods (Please send comments by one method only):

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

• *NCUA Web Site: http://www.ncua.gov/Legal/Regs/Pages/PropRegs.aspx.* Follow the instructions for submitting comments.

• *Email:* Address to *regcomments@ncua.gov.* Include ''[Your name] Comments on Interim Final Rule, Section 713.6, Fidelity Bond'' in the email subject line.

• *Fax:* (703) 518–6319. Use the subject line described above for email.

• *Mail:* Address to Mary Rupp, Secretary of the Board, National Credit Union Administration, 1775 Duke Street, Alexandria, Virginia 22314–3428.

• *Hand Delivery/Courier:* Same as mail address.

Public Inspection: You can view all public comments on NCUA's Web site at *http://www.ncua.gov/Legal/Regs/Pages/PropRegs.aspx* as submitted, except for those we cannot post for technical reasons. NCUA will not edit or remove any identifying or contact information from the public comments submitted. You may inspect paper copies of comments in NCUA's law library at 1775 Duke Street, Alexandria, Virginia 22314, by appointment weekdays between 9 a.m. and 3 p.m. To make an appointment, call (703) 518–6546 or send an email to *OGCMail@ncua.gov.*

FOR FURTHER INFORMATION CONTACT: Chrisanthy Loizos, Staff Attorney, Office of General Counsel, at the above address or telephone (703) 518–6540, or Matthew J. Biliouris, Director of Supervision, or J. Owen Cole, Director, Division of Capital Markets, Office of Examination and Insurance, at the above address or telephone (703) 518–6360.

SUPPLEMENTARY INFORMATION:

I. Background

a. Why is NCUA adopting this rule?

On July 11, 2011, President Obama issued Executive Order 13579, ordering independent agencies, including NCUA, to consider whether they can modify, streamline, expand, or repeal existing rules to make their programs more effective and less burdensome. Consistent with the spirit of the Executive Order and as part of NCUA's Regulatory Modernization Initiative, the NCUA Board (Board) is adopting this rule to streamline its regulatory program by eliminating RegFlex. The final rule relieves regulatory burden on federal credit unions (FCUs) because they will no longer need to engage in any process for a RegFlex designation. In addition, the final rule provides regulatory relief to FCUs that are currently not RegFlex eligible because it extends to them most of the flexibilities previously available only to RegFlex FCUs.

The Board issued a Notice of Proposed Rulemaking (NPRM) in December 2011. 76 FR 81421 (Dec. 28, 2011). The comment period on the proposed rule ended on February 27, 2012. NCUA received seventeen comment letters on the NPRM: Four from FCUs, three from trade associations (1 representing banks, 2 representing credit unions), nine from state credit union leagues, and one from a law firm. The majority of the commenters supported the rulemaking generally. Four commenters did not support the rule as proposed, and the remaining commenters offered comments on particular provisions but did not take a position on the initiative as a whole. For the reasons discussed below, the Board is adopting the amendments almost exactly as proposed. As such, the Board does not restate the legal analysis it presented in the NPRM's preamble and incorporates it by reference here in this rulemaking. *Id.*

b. What was RegFlex?

The Board established RegFlex in 2002. 66 FR 58656 (Nov. 23, 2001). RegFlex relieved FCUs from certain regulatory restrictions and granted them additional powers if they demonstrated sustained superior performance as measured by CAMEL rating and net worth classification. An FCU could qualify for RegFlex treatment automatically or by application to the appropriate regional director. Specifically, an FCU automatically qualified for a RegFlex designation when it received a composite CAMEL rating of ''1'' or ''2'' for two consecutive examination cycles and maintained a net worth classification of ''well capitalized'' under part 702 of NCUA's rules for the last six quarters. An FCU subject to a risk-based net worth (RBNW) requirement under part 702 could also qualify for RegFlex treatment if it remained ''well capitalized'' for the last six quarters after applying the applicable RBNW requirement. FCUs that did not automatically qualify for a RegFlex designation could seek one with the appropriate regional director.

The rule gave RegFlex FCUs relief from restrictions in the following six areas or ''flexibilities'': (1) Charitable contributions; (2) nonmember deposits; (3) fixed assets; (4) zero-coupon investments; (5) borrowing repurchase transactions; and (6) commercial mortgage related securities (CMRS). It provided an additional flexibility by specifically authorizing the purchase of obligations from federally insured credit unions beyond those an FCU may purchase under the NCUA's eligible obligations rule, § 701.23. RegFlex FCUs were also permitted a higher maximum allowable deductible for fidelity bond coverage under § 713.6.

c. What changes did NCUA propose?

The Board proposed to eliminate RegFlex and the charitable contributions rule, and amend the rules that apply to eligible obligations, nonmember deposits, fixed assets, and investments, so that all FCUs could engage in activities previously permitted only for RegFlex FCUs, subject to some conditions. 76 FR 81421 (Dec. 28, 2011).

The NPRM removed the charitable contributions rule in its entirety and placed the remaining six flexibilities of the RegFlex rule into the subject-specific rules that apply to all FCUs. It adjusted the nonmember deposits rule to allow some FCUs to accept more nonmember deposits. The proposed rule extended to six years the amount of time in which all FCUs must occupy unimproved property under NCUA's fixed assets rule. The proposed amendments to the investment rule permitted extended maturities for zero-coupon investments and borrowing repurchase transactions, as well as the purchase of CMRS under similar conditions allowed for RegFlex FCUs. The NPRM moved the provisions to buy nonmember and other obligations from the RegFlex rule into the eligible obligations rule, § 701.23. Lastly, the proposal made a nonsubstantive change to the member business loan rule that cross-references RegFlex.

While providing additional regulatory flexibility, the NPRM made a few modifications to authorities and did not extend the full scope of every RegFlex authority to all FCUs. The Board proposed to remove the automatic exemption from the nonmember deposits limit that had been granted to RegFlex FCUs. In so doing, the Board noted that the change would not negatively impact those FCUs based on the volume of nonmember deposits held by them.

With regard to the investment rule amendments, the NPRM created a ''well capitalized standard'' based on the automatic designation criteria used in RegFlex. An FCU meets the well capitalized standard if it has received a composite CAMEL rating of ''1'' or ''2'' for two consecutive full examinations and (1) has maintained a ''well capitalized'' net worth classification for the immediately preceding six quarters, or (2) has remained ''well capitalized'' for the immediately preceding six quarters after applying the applicable RBNW requirement.

The proposed rule provided that well capitalized FCUs could purchase zero-coupon investments with a maximum maturity of no more than 30 years, while FCUs not meeting the standard would continue to be subject to a maturity cap of 10 years unless they received approval from their regional director. The NPRM permitted FCUs not meeting the well capitalized standard to enter into borrowing repurchase transactions in which the security purchased with the proceeds from the borrowing agreement matured no more than 30 days after the maturity of the borrowing, unless they received additional approval from their regional director. Consistent with the RegFlex program, the NPRM did not impose the 30-day mismatch restriction on FCUs meeting the well capitalized standard. The proposal limited the amount of securities that any FCU, whether well capitalized or not, could purchase with mismatched maturities to 100% of the FCU's net worth. It also permitted FCUs not meeting the well capitalized standard to purchase private label CMRS subject to an aggregate limit of 25% of net worth, unless their regional director granted authority to purchase securities in an amount up to 50% of net worth, which is the cap for FCUs meeting the well capitalized standard.

II. Summary of Comments on December 2011 Proposed Rule

A majority of commenters supported the Board's efforts to extend regulatory flexibility to FCUs. Other commenters felt the proposal did not provide enough relief and failed to extend similar relief to federally insured, state-chartered credit unions. One credit union trade association stated that the proposal removed clear eligibility standards for FCUs to obtain expanded authorities. It opposed the elimination of an appeals process to NCUA's Supervisory Review Committee, similar to the one through which RegFlex FCUs could appeal RegFlex designation revocations, if an FCU were not permitted to engage in the full range of flexibilities. The bank trade association stated that, although it supports efforts to reduce regulatory burdens, NCUA should not extend such regulatory relief to FCUs that are undercapitalized or represent supervisory concerns. Another commenter found that the RegFlex program under part 742 sufficiently accomplished its goals in its current form. The Board has carefully reviewed and analyzed the comment letters and describes specific comments on the NPRM below.

a. Charitable Contributions

In the NPRM, the Board proposed to eliminate the entire charitable contributions rule, § 701.25. Section 701.25 restricts an FCU's ability to make donations. It only allows an FCU to make charitable contributions or donations to nonprofit organizations located or conducting activities in a community in which the FCU has a place of business, or to organizations that are tax exempt under § 501(c)(3) of the Internal Revenue Code and that operate primarily to promote and develop credit unions. It further requires an FCU's board of directors to approve charitable contributions based on a determination that the contributions are in the FCU's best interests and are reasonable given the FCU's size and financial condition. Under the rule, directors may establish a budget for charitable donations and authorize FCU officials to select recipients and disburse funds. The RegFlex rule, § 742.4(a)(1), exempted RegFlex FCUs from the entire charitable contributions rule. By removing § 701.25, the Board is now allowing any FCU to make donations without the prior approval of its board of directors and without regulatory restrictions as to recipients.

In the NPRM, the Board noted that, even in the absence of a charitable contributions rule, an FCU's authority to make donations is authorized by incidental powers given in the Federal Credit Union Act (Act), 12 U.S.C. 1757(17). As such, contributions must be necessary or requisite to enable the FCU to effectively carry on its business. *See* 12 CFR 721.2. Furthermore, FCU directors have a fiduciary duty to direct management to operate within sound business practices and the best interests of the membership under § 701.4. In addition, article XVI, section 4 of the FCU Bylaws prohibits FCU directors, committee members, officers, agents, and employees from conflicts of interest that could arise in the context of making charitable donations.

Two credit union trade associations, four leagues, and three credit unions supported the elimination of the charitable contributions rule. Three of these commenters maintained that the limitations on an FCU's incidental powers, the board's fiduciary duties, and the FCU Bylaws already set the appropriate standards for charitable contributions. One commenter stated that the change would eliminate a bureaucratic hurdle and enable FCUs to further their mission of helping people of modest means. The bank trade association stated that the charitable contributions rule protects the interests of members and avoids conflicts of interest and, therefore, requested that NCUA retain it. The Board believes the Act, FCU bylaws, part 721, and § 701.4 provide sufficient constraints on an FCU's ability to make charitable contributions. Accordingly, the final rule removes § 701.25 as proposed.

One credit union commenter expressed concern that FCUs would need to seek approval to make donations because NCUA did not propose to amend § 721.3 to expressly identify charitable contributions as a preapproved incidental power. Since 1979, NCUA has recognized that FCUs may make charitable contributions under the provision in the Act that authorizes an FCU ''to exercise such incidental powers as shall be necessary or requisite to enable it to carry on effectively the business for which it is incorporated.'' 44 FR 56691 (Oct. 2, 1979); 64 FR 19441 (Apr. 21, 1999); 12 U.S.C. 1757(17). The Board appreciates the suggestion to clarify an FCU's authority to make charitable contributions and donations in the incidental powers rule. The final rule amends § 721.3 accordingly by adding a new paragraph, derived from NCUA legal opinions, identifying this authority.

b. Nonmember Deposits

The Act permits an FCU to receive shares from nonmember public units, political subdivisions, and credit unions, subject to the limits in the nonmember deposits rule, § 701.32. 12 U.S.C. 1757(6); 12 CFR 701.32. Under paragraph (b) of § 701.32, the maximum amount of all public unit and nonmember shares that an FCU may hold cannot exceed the greater of 20% of the FCU's total shares or $1.5 million. Under paragraph (c) of § 701.32, nonmember share deposits that an FCU has accepted to meet a matching requirement for a Community Development Revolving Loan Fund loan count against the nonmember deposit limit once the FCU has repaid the loan. An FCU may request an exemption from its regional director to exceed the limit. If the regional director denies the request for an exemption, the FCU may appeal the decision to the Board. The RegFlex rule exempted RegFlex FCUs from both paragraphs (b) and (c) of § 701.32, so RegFlex FCUs have not been subject to the limit on the amount of public unit and nonmember shares.

The NPRM raised the dollar threshold on the nonmember deposit limit in § 701.32(b) to $3 million. The Board acknowledged that, by eliminating RegFlex, RegFlex FCUs would lose their blanket exemption from the nonmember deposit cap. Based on the amount of nonmember deposits held by RegFlex FCUs, however, the Board stated that the proposal provided all of the necessary flexibility and regulatory relief to all FCUs without adversely affecting any of the RegFlex FCUs that have accepted nonmember deposits in excess of the cap.

Both credit union trade associations and two leagues objected to the elimination of the RegFlex blanket exemption from the nonmember deposit rule's cap because all FCUs would now need a waiver to exceed the cap. One commenter stated that most FCUs find the waiver process, in general, to be unduly burdensome, time consuming, and, on occasion, arbitrary. One commenter characterized the removal of the exemption as an unfair and inflexible approach, and another stated that the change does not represent an easing of regulatory compliance burden. Three of these commenters generally supported raising the dollar threshold, but one of the trade associations stated it was unclear why NCUA chose the new level to be $3 million. The league commenters agreed with the $3 million threshold, suggested a higher threshold, or advocated preservation of the exemption for RegFlex institutions. One commenter suggested that NCUA eliminate the cap or, at a minimum, increase it to $5 million.

Two league commenters and one credit union supported the change to the nonmember deposit dollar threshold. One commenter stated that, although the rule would eliminate the current exemption, the proposal provided the appropriate amount of flexibility and regulatory relief to FCUs without adversely impacting RegFlex FCUs. Another commenter noted that smaller asset-sized FCUs can enjoy the opportunity to acquire an increased volume of nonmember deposits.

The bank trade association supported the proposed rule's requirement that all FCUs be subject to nonmember share limits. It objected, however, to the proposed increase of the dollar threshold from $1.5 million to $3 million, citing asset liability management and liquidity concerns that could be created for some small FCUs with such an increase. The commenter stated that small FCUs may not have the necessary plans, practices, and experience to manage such an inflow of deposits. It, therefore, recommended the rule require small FCUs taking advantage of the higher threshold of $3 million to adopt policies managing the risk associated with nonmember deposits. The commenter further stated that because NCUA's Prompt Corrective Action rule, § 702.202, specifies that the prohibition on accepting nonmember deposits is a discretionary supervisory action for NCUA, undercapitalized credit unions should be prohibited from accepting or rolling over nonmember deposits.

As the Board stated in the NPRM, nonmember shares are characteristically more volatile than core member shares. This additional volatility can pose asset liability management concerns and liquidity concerns. The Board determined it was appropriate to raise the dollar threshold to $3 million because the agency's data reveals that only four RegFlex FCUs currently exceed the limitation in § 701.32(b) of the greater of 20% of total shares or $1.5 million in nonmember deposits, and each of those FCUs holds less than $3 million. To raise the maximum dollar threshold to $5 million would create a wider gap for FCUs with lower total shares from the percentage of 20% of total shares threshold without any need for such an increase. For instance, an FCU with $7.5 million in total shares has been subject to the $1.5 million and 20% percent caps of § 701.32. Under this final rule, however, the FCU will be permitted to accept up to $3 million in nonmember deposits, representing 40% of total shares. To permit this FCU to accept up to $5 million in shares would permit the FCU to accept nonmember deposits amounting to two-thirds or over 66% of its total shares. As such, the final rule maintains the proposed adjustment to the dollar threshold in paragraph (b)(1) because it maintains the regulatory relief that RegFlex FCUs have enjoyed. Furthermore, the adjustment extends relief to FCUs, particularly those FCUs that have lower amounts of total shares, and remains attentive to safety and soundness considerations. The Board also finds it unnecessary to include a blanket prohibition for undercapitalized FCUs to accept nonmember deposits in § 701.32 as suggested by one commenter. The Prompt Corrective Action rule, § 702.202(b)(6), offers NCUA the appropriate flexibility in determining whether limiting or prohibiting an undercapitalized FCU from accepting nonmember deposits is the appropriate supervisory action under particular facts.

c. Fixed Assets

The Act authorizes an FCU to purchase, hold, and dispose of property necessary or incidental to its operations. 12 U.S.C. 1757(4). Generally, the fixed assets rule provides limits on fixed asset investments, establishes occupancy and other requirements for acquired and abandoned premises, and prohibits certain transactions. 12 CFR 701.36. ''Fixed assets'' is defined in § 701.36(e) and includes premises. ''Premises'' means any office, branch office, suboffice, service center, parking lot, facility, or real estate where a credit union transacts or will transact business.

When an FCU acquires premises for future expansion and does not fully occupy the space within one year, the rule requires the FCU's board of directors to have a resolution in place by the end of that year with plans for full occupation. 12 CFR 701.36(b)(1). Additionally, the FCU must partially occupy the premises within three years, unless the FCU obtains a waiver within 30 months of acquiring the premises. 12 CFR 701.36(b)(1)–(2). RegFlex FCUs have enjoyed more flexibility by having authority to take up to six years to partially occupy unimproved land they acquired for future expansion. 12 CFR 701.36(d), 742.4(a)(3). In the NPRM, the Board proposed to amend the fixed assets rule to extend the three-year time period to six years for any FCU that acquires unimproved land.

One credit union trade association, five leagues, and two credit unions supported the proposed extension of time from three years to six years. One league noted that, while most FCUs will probably not use the expanded time frame, the flexibility will assist them in implementing building plans efficiently. Another league stated that the change provides relief to FCUs that acquired land during better economic times or rates. It noted that, under the proposed extension, FCUs will not be forced to choose between seeking a waiver or selling land because they could not meet the three-year timeline.

As noted in the NPRM's preamble and discussed in previous rulemakings, the Board recognizes that many real estate transactions are complex and time consuming, and they involve a full array of issues that an FCU must address before it is ready to occupy the premises. This is especially true in the unimproved land context with its construction-related issues. The final rule adopts the change to the fixed assets rule as proposed by permitting any FCU a longer time (up to six years, rather than only three years) to partially occupy the premises if it initially acquired the property as unimproved land.

d. Investment Authorities

Some of the commenters provided general comments applicable to most or all facets of the NPRM's proposed changes to the investment rule. One credit union generally supported the ability of all FCUs to invest in zero-coupon investments and CMRS, as well as to engage in borrowing repurchase transactions. Two leagues stated that, while their members were generally supportive of giving FCUs expanded investment authorities, these relatively sophisticated financial instruments require a baseline of expertise. The commenters stated that the rule should include requirements for staff to have demonstrated expertise to handle these transactions. One league argued that the proposal's well capitalized standard merely eliminates the RegFlex designation while preserving the same restrictions on eligibility. As such, the commenter urged NCUA to consider whether the current restrictions on some types of investments should be removed for more FCUs to allow flexibility in diversifying investments and to reduce reliance on the ''currently limited'' investments allowed under NCUA's rules. The Board maintains the standards and conditions for the various investment authorities set forth the proposed rule as discussed in the responses to specific comments below.

1. Zero-coupon Investments

Under § 703.16(b), an FCU may not purchase a zero-coupon investment with a maturity date that is more than 10 years from the related settlement date. RegFlex FCUs have been exempt from the maximum maturity length of 10 years in the investment rule. 12 CFR 742.4(a)(4). To balance the risk management concerns inherent in zero-coupon investments with the flexibility previously granted to RegFlex FCUs, the Board proposed to establish the maximum maturity date of zero-coupon investments to 30 years for any FCU that meets the NPRM's well capitalized standard. The Board proposed to grandfather zero-coupon investments purchased in accordance with § 742.4(a)(4) before the effective date of the final rule, so FCUs that purchased zero-coupon investments with maturities greater than 10 years under RegFlex authority would not be required to divest those investments. The proposed rule also provided that an FCU not meeting the well capitalized standard may only purchase a zero-coupon investment with a maturity date that is no more than 10 years from the related settlement date, unless it received approval from its regional director to purchase such an investment with a greater maturity.

Three commenters objected to the proposed rule change for zero-coupon investments. One credit union trade association encouraged NCUA to eliminate the 10-year maturity limit for zero-coupon investments. One credit union stated the current rule is sufficient. Both of these commenters stated that this issue is more appropriately addressed within an FCU's investment policy. One league stated that it is more appropriate to adopt a rule specific to interest rate risk rather than remove the current flexibility afforded to certain RegFlex FCUs.

Two leagues supported the proposed changes regarding zero-coupon investments. One commenter stated that it is reasonable to require an FCU that does not meet the well capitalized standard to obtain approval from its regional director to purchase a zero-coupon investment with a maturity greater than ten years. The commenter also supported the creation of a maximum maturity date of 30 years for well capitalized FCUs. Another commenter suggested that the proposal include greater flexibility by permitting well capitalized FCUs to pursue a waiver from the 30-year maturity limit, as other FCUs would have the option to seek waivers from their 10-year maturity cap.

As the Board noted in the NPRM's preamble, the percentage loss on zero-coupon investments increases dramatically with maturity. These losses could make FCUs reluctant to sell zero-coupon investments and recognize losses during periods of liquidity stress. Therefore, consistent with safety and soundness principles, the Board does not believe it is appropriate to allow FCUs to purchase or hold zero-coupon investments with maturity dates that exceed 30 years. Accordingly, the Board adopts the final rule as proposed.

2. Borrowing Repurchase Transactions

A borrowing repurchase transaction is a transaction in which an FCU agrees to sell a security to a counterparty and to repurchase the same or an identical security from that counterparty at a specified future date and at a specified price. 12 CFR 703.2. Subject to additional restrictions, an FCU may enter into a borrowing repurchase transaction as long as any investments the FCU purchases with borrowed funds mature no later than the maturity of the borrowing repurchase transaction. 12 CFR 703.13(d).

While the investment rule prohibits an FCU from purchasing a security with the proceeds from a borrowing repurchase agreement if the purchased security matures after the maturity of the borrowing repurchase agreement, NCUA adopted a limited exemption for RegFlex FCUs from the maturity restriction. 12 CFR 703.13(d)(3); 68 FR 32958, 32959 (June 3, 2003). A RegFlex FCU has been permitted to purchase securities with maturities exceeding the maturity of the borrowing repurchase transaction, commonly referred to as having mismatched maturities, provided the amount of any such purchased securities does not exceed the FCU's net worth. 12 CFR 742.4(a)(5).

In the NPRM, the Board proposed to continue this flexibility of mismatched maturities for borrowing repurchase transactions for FCUs meeting the well capitalized standard. It also proposed to grandfather borrowing repurchase transactions into which an FCU entered pursuant to its RegFlex authority before the effective date of the final rule. The Board also sought to extend relief from the maturity requirement to FCUs not meeting the well capitalized standard. Under the proposed rule, these FCUs could enter into borrowing repurchase transactions and use the proceeds to purchase investments with maturities no more than 30 days later than the transaction's term, so long as the value of the purchased investments would not exceed the related FCU's net worth. In addition, under the NPRM, FCUs not meeting the well capitalized standard would be allowed to request additional authority from their regional directors to enter transactions whereby the maturity mismatch would be greater than 30 days. Lastly, the Board sought comment on whether the final rule should specify minimum experience requirements for staff involved in the analysis and ongoing risk management of a repurchase agreement book, especially in cases where maturities of sources and uses are mismatched.

Two leagues and one credit union supported the revised standards on maturity matching for borrowing repurchase transactions. One credit union requested that the final rule permit FCUs that are well capitalized under part 702 but that do not have a CAMEL rating of 1 or 2 to enter these transactions without a maturity mismatch limitation, provided the assets pledged are guaranteed by a governmental agency or government-sponsored enterprise. One credit union trade association did not support any minimum experience requirements for staff involved in the analysis and ongoing risk management of borrowing repurchase transactions, arguing that FCUs should have the flexibility to hire qualified personnel without comparing the applicant to a predetermined set of NCUA criteria.

The final rule makes no substantive change to the proposed rule. It does clarify, however, that when an FCU purchases investments that have mismatched maturities under borrowing repurchase agreements, the aggregate or total value of purchased investments made under these conditions cannot exceed the FCU's net worth. Therefore, under the final rule, an FCU may purchase investments with maturities exceeding the maturity of the borrowing repurchase transaction if the aggregate amount of all such purchased investments does not exceed its net worth. The Board notes that the final rule does not create an exception for purchased investments that are guaranteed by a government agency or government-sponsored entity because the conditions on maturity mismatches are intended to address interest rate risk, rather than default risk. The suggested exception would not further the Board's goal. In addition, the final rule does not include experience requirements. The Board again reminds FCUs, however, that they should position themselves, through in-house or contracted expertise, to properly engage in the analysis and ongoing risk management of borrowing repurchase transactions.

3. Commercial Mortgage Related Security (CMRS)

Pursuant to section 107(15)(B) of the Act, a RegFlex FCU had been permitted to purchase CMRS that are not otherwise permitted by section 107(7)(E) of the Act if: (i) the security is rated in one of the two highest rating categories by at least one nationally-recognized statistical rating organization (NRSRO); (ii) the security meets the definition of mortgage related security as defined in 15 U.S.C. 78c(a)(41) and the definition of CMRS in § 703.2; (iii) the pool of loans underlying the CMRS contains more than 50 loans with no one loan representing more than 10 percent of the pool; and (iv) the FCU does not purchase an aggregate amount of CMRS in excess of 50 percent of its net worth. 12 CFR 742.4(a)(6). In the NPRM, the Board proposed to permit FCUs meeting the well capitalized standard to purchase private label CMRS under these same conditions.

The Board also proposed to permit an FCU not meeting the well capitalized standard to purchase private label CMRS under the conditions applicable to well capitalized FCUs, but it limited the aggregate amount of CMRS to 25 percent of the FCU's net worth. The NPRM permitted such an FCU to seek authorization from its regional director to purchase a greater amount of CMRS, up to 50 percent of its net worth, if it could demonstrate three consecutive years of effective CMRS portfolio management and the ability to evaluate key risk factors. The proposed rule also added a grandfather provision for private label CMRS purchased by an FCU under its RegFlex authority before the effective date of the final rule. In the NPRM, the Board sought comment on whether the conditions for purchasing CMRS should be enhanced to encourage diversity and mitigate risk.

One league and one credit union supported the changes for CMRS as proposed. One credit union trade association advocated additional authority for FCUs in this area and supported removal of limitations on CMRS that are not required by the Act. One credit union stated its particular concern with the proposal because it believes the failure of the corporate credit union system was caused by significant concentrations of private label mortgage related securities. The commenter stated that the proposed rule lacks sufficient guidance related to credit risk management. It suggested that, at a minimum, the rule require: pre-purchase credit analysis, including analysis of underlying collateral, geographic diversification, cash flows, and credit structures, as well as identification and general avoidance of subordinated tranches that represent elevated levels of credit risk in favor of senior tranches; documentation and retention of credit analyses for as long as an FCU holds the CMRS; and ongoing credit monitoring to identify emerging negative trends and potential concerns. While the Board does not incorporate these conditions in the final rule, the Board strongly believes the commenter has identified best practices to which FCUs should adhere if they are to purchase CMRS. The Board adopts the provisions regarding CMRS in the final rule as proposed.

e. Eligible Obligations

The eligible obligations rule permits an FCU to purchase loans from any source, provided that two conditions are satisfied. 12 CFR 701.23. First, the borrower is a member of that FCU. Second, the loan is either of a type the FCU is empowered to grant or the FCU refinances the loan within 60 days of its purchase so that it meets the empowered to grant requirement. 12 CFR 701.23(b)(1)(i). The rule also permits an FCU to purchase student loans and real estate-secured loans, from any source, if the purchasing FCU grants these loans on an ongoing basis and is purchasing either type of loan to facilitate the packaging of a pool of such loans for sale or pledge in the secondary market. 12 CFR 701.23(b)(1)(iii)–(iv). An FCU may also purchase the obligations of a liquidating credit union's individual members from the liquidating credit union. 12 CFR 701.23(b)(ii). The eligible obligations rule restricts the aggregate amount of loans that an FCU may purchase to five percent of the purchasing FCU's unimpaired capital and surplus. 12 CFR 701.23(b)(3). It excludes certain types of loans from this limit, including loans purchased to facilitate a sale or pledge in the secondary market. 12 CFR 701.23(b)(3).

RegFlex FCUs have been permitted to buy loans from other federally insured credit unions without regard to whether the loans are eligible obligations of the purchasing FCU's members or the members of a liquidating credit union. 12 CFR 742.4(b). Loans purchased from a liquidating credit union, however, are subject to the cap of five percent of unimpaired capital and surplus. 12 CFR 742.4(b)(4); 66 FR 15055, 15059 (Mar. 15, 2001). RegFlex FCUs also have been able to purchase student loans and real estate-secured loans without the requirement that loans be purchased to facilitate a secondary market pool package. 12 CFR 742.4(b).

The NPRM retained the flexibility currently provided to RegFlex FCUs for FCUs meeting the well capitalized standard. The proposed rule also grandfathered all eligible obligations purchased by RegFlex FCUs before the effective date of the final rule. The proposed rule similarly amended paragraph (e) in § 723.1 to address nonmember business loans purchased under RegFlex authority or obligations purchased under proposed § 701.23(b)(2). The Board requested specific comment on whether it should extend the flexibility from the eligible obligations rule to all FCUs or establish an approval process through regional directors for FCUs not meeting the well capitalized standard.

One league supported the expansion in the eligible obligations rule. One credit union trade association recommended, at a minimum, an expansion of this authority to allow FCUs that are somewhat less than well capitalized to take advantage of the flexibility afforded to FCUs meeting the well capitalized standard. Likewise, one league and one credit union commenter urged NCUA to extend the flexibility for eligible obligations to all FCUs or provide a waiver process similar to the process for other expanded authorities. One commenter stated that eligible obligation purchases that are made after an FCU applies proper due diligence do not pose a safety and soundness issue for that FCU or the National Credit Union Share Insurance Fund. The credit union commenter also urged NCUA to expand the purchasing authority to all FCUs so they can benefit from the stabilizing effects of purchasing well-performing obligations from diverse portfolios of other federally insured credit unions. The commenter further stated that an expansion would enhance safety and soundness in two ways. First, a purchasing FCU can increase earnings by deploying excess liquidity into higher yielding, high quality assets when loan demand from its members may be low. Second, a purchasing FCU can reduce concentration risk because selling institutions have different fields of membership. The commenter also made suggestions to clarify the proposed regulatory text in § 701.23.

The final rule substantively adopts the provisions in the proposed rule pertaining to eligible obligations with two changes. It includes a provision that allows FCUs not meeting the well capitalized standard to seek authority from their regional directors to purchase obligations from other federally insured credit unions under the same conditions applicable to FCUs that do meet the well capitalized standard. The final rule also uses plain language rather than paragraph citations within § 701.23 for ease of reading.

III. Final Rule

a. RegFlex

The final rule removes part 742 from title 12 to eliminate RegFlex as the Board proposed in the NPRM. The Board noted in the preamble to the proposed rule that it would address the appeals process before NCUA's Supervisory Review Committee for RegFlex designation revocations. In a separate, contemporaneous rulemaking, the Board is amending NCUA Interpretive Ruling and Policy Statement 11–1, 76 FR 23871 (Apr. 29, 2011), to remove RegFlex appeals from the purview of the committee because RegFlex no longer exists as of the effective date of this rule.

b. Charitable Contributions

The final rule removes the entire charitable contributions rule, § 701.25, from part 701. With the deletion of this section, an FCU will no longer be restricted by regulation to make donations only to certain recipients and will not be required to obtain prior approval from its board of directors. An FCU's authority to make donations will continue to be governed by its incidental powers authority under the Act, the fiduciary duties of its board, and its bylaws. NCUA has long recognized an FCU's authority to make charitable contributions and donations because an FCU may ''exercise such incidental powers as shall be necessary or requisite to enable it to carry on effectively the business for which it is incorporated.'' 44 FR 56691 (Oct. 2, 1979); 64 FR 19441 (Apr. 21, 1999); 12 U.S.C. 1757(17). Contributions, therefore, must be necessary or requisite to enable the FCU to effectively carry on its business. 12 CFR 721.2. Furthermore, FCU directors have a fiduciary duty to direct management to operate within sound business practices and the best interests of the membership under § 701.4. In addition, article XVI, section 4 of the FCU Bylaws prohibits FCU directors, committee members, officers, agents, and employees from conflicts of interest that could arise in the context of making charitable donations.

As noted, the making of charitable contributions has long been recognized by NCUA as an approved incidental power. The final rule, therefore, amends § 721.3 by adding a new paragraph (b) to identify this authority and renumbers the remaining activities in the section.

c. Nonmember Deposits

The final rule raises the dollar threshold on the nonmember deposit limit in § 701.32(b) from $1.5 million to $3 million. The maximum amount of all public unit and nonmember shares that any FCU may hold cannot exceed the greater of 20 percent of the FCU's total shares or $3 million. Unlike the former RegFlex rule, the final rule does not provide a standardized exemption from the nonmember deposit cap. Section 701.32, however, continues to permit an FCU to request from its regional director an exemption to exceed the limit on the maximum amount of nonmember deposits. 12 CFR 701.32(b)(3)–(5). If the regional director denies the request for an exemption, the FCU may appeal the decision to the Board. 12 CFR 701.32(b)(5).

d. Fixed Assets

The final rule amends § 701.36(b)(2) to permit any FCU a six-year time frame to partially occupy the premises if the FCU acquired unimproved land for its future expansion. As in the current rule, premises are partially occupied when the FCU is using some part of the space on a full-time basis. An FCU may request a waiver from the partial occupation requirement. The amendment applies only to unimproved real property and does not apply to any other kind of premises.

e. Zero-Coupon Investments

In order to balance the risk management concerns discussed in the NPRM, the final rule restricts FCUs meeting the well capitalized standard from purchasing any zero-coupon investment with a maturity date greater than 30 years. It also provides that an FCU not meeting the well capitalized standard may not purchase a zero-coupon investment with a maturity date that is more than 10 years from the related settlement date, unless it has received approval from its regional director to purchase such an investment with a greater maturity. In addition, the final rule grandfathers zero-coupon investments purchased under RegFlex authority before the effective date of this rule.

FCUs considering the purchase of zero-coupon investments should be familiar with the dramatic rise in percentage loss on these investments with maturity. Only FCUs with the appropriate level of expertise positioned to measure the safety and soundness of purchasing zero-coupon investments with extended maturities should consider such investments.

f. Borrowing Repurchase Transactions

Section 703.13(d)(3)(iii) of the final rule permits FCUs meeting the well capitalized standard to purchase investments with maturities exceeding the maturity of the borrowing repurchase transaction. Section 703.13(d)(3)(ii) permits FCUs not meeting the well capitalized standard to enter into borrowing repurchase transactions and use the proceeds to purchase investments with maturities no more than 30 days later than the transaction's term. Under § 703.20, these FCUs may request additional authority from their regional directors to enter transactions whereby the maturity mismatch would be greater than 30 days. The final rule also clarifies that the total value of investments that any FCU purchases through transactions with mismatched maturities cannot exceed its net worth. In addition, the final rule contains a grandfather provision for borrowing repurchase transactions into which an FCU entered under its RegFlex authority before the effective date of this rule.

The final rule, therefore, sets out three possible scenarios for borrowing repurchase transactions under § 703.13(d)(3). In the first instance, the borrowing and corresponding investment transactions must have matched maturities. In the second instance, the matched maturity requirement would not apply if an FCU buys investments that mature no more than 30 days after the maturity of the borrowing repurchase transaction and the aggregate or total value of those investments does not exceed 100 percent of the FCU's net worth. In the third instance, an FCU that meets the well capitalized standard may enter borrowing repurchase transactions with mismatched maturities greater than 30 days if the total value of investments purchased through transactions with mismatched maturities does not exceed 100 percent of the FCU's net worth.

g. CMRS

The final rule removes the prohibition in § 703.16 on the purchase of private label CMRS. The final rule permits an FCU that meets the well capitalized standard to purchase CMRS that are not otherwise permitted by section 107(7)(E) of the Act if: (i) the security is rated in one of the two highest rating categories by at least one NRSRO; [1] (ii) the security meets the definition of mortgage related security as defined in 15 U.S.C. 78c(a)(41) and the definition of CMRS in § 703.2; (iii) the pool of loans underlying the CMRS contains more than 50 loans with no one loan representing more than 10 percent of the pool; and (iv) the FCU does not purchase an aggregate amount of CMRS in excess of 50 percent of its net worth. The final rule provides that an FCU that does not meet the well capitalized standard may purchase private label CMRS under conditions (i) through (iii) above, but limits the aggregate amount of private label CMRS to 25 percent of its net worth. Section 703.20 establishes an approval process so that such an FCU may seek authorization from its regional director to purchase a greater amount of CMRS, up to a maximum of 50% of its net worth. As part of its request for approval, an FCU must demonstrate three consecutive years of effective CMRS portfolio management and the ability to evaluate key risk factors.

Finally, the final rule adds a grandfather provision to § 703.18 for private label CMRS purchased by an FCU under its RegFlex authority before the effective date of this rule. As such, an FCU that does not meet the well capitalized standard, but which holds private label CMRS in excess of 25% of its net worth on the effective date of this rule, is not required to divest those holdings on its books. The FCU, however, cannot make additional purchases of CMRS while its aggregate CMRS holdings exceed 25% of its net worth, without the approval from the appropriate regional director under § 703.20.

The Board notes again that the authority to purchase private label CMRS, as with all of the flexibilities in the final rule, is not appropriate for every FCU. Selection of CMRS consistent with safety and soundness requires careful analysis of the underlying commercial mortgages and corresponding collateral, as well as analysis of the cash flow, credit structure, and market performance of the security.

As with all investments, FCUs must understand and be capable of managing the risks associated with CMRS before purchasing them. The investment rule's § 703.3 requires an FCU's board of directors to develop investment policies that address credit, liquidity, interest rate, and concentration risks. 12 CFR 703.3. The policy must also identify the characteristics of any investments that are suitable for the FCU. FCUs that purchase CMRS must develop sound risk management policies and construct limits that represent the FCU board's risk tolerance. If necessary, NCUA may require an FCU to divest its investments or assets for substantive safety and soundness reasons, on a case-by-case basis.

h. Eligible Obligations

The final rule renumbers § 701.23 and, under paragraph (b)(2), permits FCUs that meet the well capitalized standard to buy loans from other federally insured credit unions without regard to whether the loans are eligible obligations of the purchasing FCU's members or the members of a liquidating credit union. The final rule

[1] As required by Section 939A of the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank), the Board issued a proposal on March 1, 2011 to change this prong in part 742 with the following language: ''The issuer has at least a very strong capacity to meet its financial obligations, even under adverse economic conditions, for the projected life of the security.'' 76 FR 11164 (Mar. 1, 2011). When NCUA adopts a final rule for the proposed rulemaking issued in March 2011, the standard will change accordingly.

subjects loans purchased from a liquidating credit union to the eligible obligations cap of five percent of unimpaired capital and surplus. FCUs meeting the well capitalized standard may also purchase student loans and real estate-secured loans without the requirement that the loans be purchased to facilitate a secondary market pool package. The final rule also grandfathers all obligations purchased under RegFlex authority before the effective date of this rule and makes a similar amendment to paragraph (e) in § 723.1 to address nonmember business loans purchased under RegFlex authority or obligations under § 701.23(b)(2).

In addition, the final rule permits FCUs that do not meet the well capitalized standard to request authority from their regional directors to engage in this activity through a written request similar to the process created in paragraph (b) of § 703.20.

IV. The Interim Final Rule and Request for Comment

In issuing the proposed rule, NCUA inadvertently omitted changes to RegFlex references in its rule setting the permissible deductible for fidelity bond coverage. 12 CFR 713.6. That rule establishes a formula for calculating the maximum allowable deductible based on asset size with a cap of $200,000, but permits RegFlex FCUs a higher maximum deductible of up to $1 million. 12 CFR 713.6(a)(1), (c). With the elimination of RegFlex, the Board is issuing an interim final rule to amend the fidelity bond rule so that it is consistent with the other subject-specific rules discussed in this preamble. The interim final rule changes the applicable benchmark for increased deductible limits in § 713.6 from RegFlex FCUs to FCUs meeting the same well capitalized standard used in the other rules impacted by the elimination of RegFlex.

The amendments track those that the Board makes in the final rule, as well as the § 713.6 provisions the Board adopted in 2005 for FCUs that automatically qualified for a RegFlex designation. 70 FR 61713 (Oct. 26, 2005)

The interim final rule permits a maximum deductible for fidelity bond coverage of $1 million if the FCU has: (1) Received a composite CAMEL rating of ''1'' or ''2'' during its last two full examinations and (2) maintained a ''well capitalized'' net worth classification for the immediately preceding six quarters or has remained ''well capitalized'' for the immediately preceding six quarters after applying the applicable RBNW requirement.

Once a year, an FCU meeting the interim final rule's well capitalized standard must review its continued eligibility for a higher deductible under the rule, which is the same approach applied by the Board when it adopted the fidelity bond RegFlex provisions in 2005. *Id.* at 61714. An FCU's continued eligibility will be based on its asset size as reflected in its most recent year-end 5300 call report and its net worth as reflected in that same report. If an FCU that previously qualified for the higher deductible has a decrease in assets based on its most recent year-end 5300 call report or its net worth has decreased so that it would no longer qualify under the well capitalized standard in the rule, then it must obtain the coverage otherwise required by § 713.6. Likewise, if an FCU meets the assets threshold and its net worth would otherwise continue to qualify it for the well capitalized standard, but it failed to receive either a CAMEL rating of 1 or 2 during its most recent examination report, it must obtain the required coverage with a deductible of no more than $200,000.

The Board is adopting this rulemaking as an interim final rule because it meets the good cause exception to the procedures under the Administrative Procedure Act (APA), 5 U.S.C. 553(b)(3). Notice and public procedures are impracticable and contrary to the public interest in this matter because the final rule eliminates RegFlex. To maintain cross-references to RegFlex in the fidelity bond coverage rule would cause confusion in implementation by FCUs, as well as undue and untimely execution of NCUA's functions in monitoring compliance with § 713.6. The interim final rule complements the final rule, and it is appropriate for the Board to synchronize its adoption of all of the rule changes made in this document. The Board finds these reasons are good cause to dispense with the APA's notice and comment period and the procedures in NCUA's Interpretive Ruling and Policy Statement 87–2. 5 U.S.C. 553(b)(3)(B); 52 FR 35213 (Sept. 18, 1987), as amended by 68 FR 31949 (May 29, 2003). The interim final rule has an effective date 30 days after publication in the **Federal Register**, which coincides with the final rule's effective date. Although the rule is being issued as an interim final rule, the Board encourages interested parties to submit comments within 60 days so the Board can consider any amendments to the rule.

V. Rule Summary Table

In a further effort to comply with the Plain Writing Act of 2010 (Pub. L. 111–274), the Board includes the following table to assist readers by distinguishing the authorities for FCUs that meet the well capitalized standard and FCUs that do not. We are providing this table for your reference only. Please refer to regulatory text, as well as the preambles for the NPRM and the final rule, for specific information.

Final rule authority	FCUs meeting well capitalized standard	FCUs not meeting well capitalized standard
Charitable Contributions	Well capitalized FCUs may make donations consistent with their incidental powers authority and board's fiduciary duties.	This flexibility applies to all FCUs.
Nonmember Deposits	May accept up to the greater of 20% total shares or $3 million. May request exemption from regional director for greater amount.	This flexibility applies to all FCUs.
Unimproved Property for Future Expansion	May take up to six years to partially occupy unimproved real property purchased for future expansion.	This flexibility applies to all FCUs.
Zero-coupon Investments*	May purchase zero-coupon investments with maturity dates up to 30 years.	May purchase zero-coupon investments with maturity dates up to 10 years. May request authority from regional director for maturities up to 30 years.

Final rule authority	FCUs meeting well capitalized standard	FCUs not meeting well capitalized standard
Borrowing Repurchase Transaction*	May enter into Borrowing Repurchase Transactions where the underlying investments mature later than the borrowing, provided the total amount of investments purchased do not exceed 100 percent of net worth.	May enter into Borrowing Repurchase Transactions where the underlying investments mature no later than 30 days after the borrowing, provided the total amount of investments purchased do not exceed 100 percent of net worth. May request authority from regional director for longer maturity mismatch.
Private Label Commercial Mortgage Related Security (CMRS)*.	Not restricted to purchasing only CMRS issued by Fannie Mae or Freddie Mac. May purchase Private Label CMRS if: (i) the security is rated in one of the two highest rating categories by at least one NRSRO; (ii) it is a ''mortgage related security'' under the Securities Exchange Act of 1934 and § 703.2;	Similar flexibilities apply to all FCUs, under the following conditions: Requirements (i)–(iii) would be the same as for Well Capitalized FCUs. The limit in requirement (iv) is 25 percent of net worth. May request approval from the regional director for higher limit, up to 50 percent of net worth, if FCU has 3 consecutive years of effective CMRS portfolio management and the ability to evaluate key risk factors.
	(iii) the pool of loans underlying the CMRS contains more than 50 loans with no one loan representing more than 10 percent of the pool; and (iv) the FCU does not purchase an aggregate amount in excess of 50 percent of net worth.	
Purchase of Eligible Obligations *	In addition to the authority in the current § 701.23, may buy loans from other federally insured credit unions without regard to whether the loans are obligations of the purchasing FCU's members. May also purchase nonmember student loans and real estate loans without the need for purchase to facilitate a secondary market pool package. Also may purchase loans from a liquidating credit union regardless of whether the loans were made to liquidating CU's members, subject to the aggregate cap on eligible obligations of 5 percent of unimpaired capital and surplus.	These flexibilities may be extended if approved by regional director, otherwise limited to the other provisions of § 701.23 for purchasing eligible obligations (subject to membership or pooling requirements)
Fidelity Bond Coverage—Maximum Deductible for FCUs with Over $1 million in Assets.	$2,000 plus 1/1000 of total assets up to a maximum of $1,000,000.	$2,000 plus 1/1000 of total assets up to a maximum of $200,000.

* All authorized activity entered into before the effective date of the final rule is grandfathered.

VI. Regulatory Procedures

a. Regulatory Flexibility Act

The Regulatory Flexibility Act requires NCUA to prepare an analysis to describe any significant economic impact a rule may have on a substantial number of small entities (primarily those under ten million dollars in assets). This rule reduces compliance burden and extends regulatory relief while maintaining existing safety and soundness standards. NCUA has determined and certifies that this rule will not have a significant economic impact on a substantial number of small credit unions.

b. Paperwork Reduction Act

The Paperwork Reduction Act of 1995 (PRA) applies to rulemakings in which an agency by rule creates a new paperwork burden on regulated entities or modifies an existing burden. 44 U.S.C. 3507(d); 5 CFR part 1320. For purposes of the PRA, a paperwork burden may take the form of either a reporting or a recordkeeping requirement, both referred to as information collections. As required, NCUA has applied to the Office of Management and Budget (OMB) for approval of the information collection requirement described below.

The final rule contains an information collection in the form of a voluntary written request for additional authorities from a regional director under proposed § 703.20 and § 701.23(h). An FCU that does not meet the well capitalized standard may submit a written request to its regional director to request expanded authority above any or all of the following provisions in the rule: (1) The borrowing repurchase transaction maximum maturity mismatch of 30 days under proposed § 703.13(d)(3)(ii), (2) the zero-coupon investment 10-year maximum maturity under proposed § 703.14(i), up to a maturity of no more than 30 years, (3) the aggregate commercial mortgage related security limit of 25% of net worth under proposed § 703.14(j), up to no more than 50% of net worth, and (4) the membership and pooling limitations in § 701.23(b)(1) when purchasing loans under § 701.23(b)(2). An FCU meets the well capitalized standard if the FCU has received a composite CAMEL rating of ''1'' or ''2'' during its last two full examinations and (1) has maintained a ''well capitalized'' net worth classification for the immediately preceding six quarters, or (2) has remained ''well capitalized'' for the immediately preceding six quarters after applying the applicable RBNW requirement. In the proposed rule, the Board estimated 1,770 FCUs may apply for an additional authority. The cumulative total annual paperwork burden is estimated to be approximately 1,770 hours.

OMB is currently reviewing NCUA's submission and NCUA will publish the OMB number assigned to this rulemaking once issued.

c. Executive Order 13132

Executive Order 13132 encourages independent regulatory agencies to consider the impact of their actions on state and local interests. NCUA, an independent regulatory agency as defined in 44 U.S.C. 3502(5), voluntarily complies with the executive order to adhere to fundamental federalism principles. This final rule will not have a substantial direct effect on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government. NCUA has determined that this rule does not constitute a policy that has federalism implications for purposes of the executive order.

d. Small Business Regulatory Enforcement Fairness Act

The Small Business Regulatory Enforcement Fairness Act of 1996 (Pub. L. 104–121) provides generally for congressional review of agency rules. A reporting requirement is triggered in instances where NCUA issues a final rule as defined by Section 551 of the Administrative Procedure Act. 5 U.S.C. 551. The Office of Management and Budget has determined that this rule is not a major rule for purposes of the Small Business Regulatory Enforcement Fairness Act of 1996.

e. Assessment of Federal Regulations and Policies on Families

NCUA has determined that this final IRPS will not affect family well-being within the meaning of Section 654 of the Treasury and General Government Appropriations Act, 1999, Public Law 105–277, 112 Stat. 2681 (1998).

List of Subjects

12 CFR Part 701

Credit unions.

12 CFR Part 703

Credit unions, Investments.

12 CFR Part 713

Credit unions, Insurance, Reporting and recordkeeping requirements.

12 CFR Part 721

Credit unions.

12 CFR Part 723

Credit, Credit unions, Reporting and recordkeeping requirements.

12 CFR Part 742

Credit unions, reporting and recordkeeping requirements.

By the National Credit Union Administration Board on May 24, 2012.

Mary Rupp,

Secretary of the Board.

For the reasons discussed above, NCUA amends 12 CFR parts 701, 703, 713, 721, 723, and 742 as follows:

PART 701—ORGANIZATION AND OPERATIONS OF FEDERAL CREDIT UNIONS

■ 1. The authority citation for part 701 continues to read as follows:

Authority: 12 U.S.C. 1752(5), 1755, 1756, 1757, 1759, 1761a, 1761b, 1766, 1767, 1782, 1784, 1787, and 1789. Section 701.6 is also authorized by 31 U.S.C. 3717. Section 701.31 is also authorized by 15 U.S.C. 1601 *et seq.,* 42 U.S.C. 1861 and 42 U.S.C. 3601–3610. Section 701.35 is also authorized by 42 U.S.C. 4311–4312.

■ 2. In § 701.23:
■ a. Redesignate paragraphs (b)(2) and (3) as paragraphs (b)(3) and (4);
■ b. Add new paragraph (b)(2):
■ c. In newly redesignated paragraph (b)(4) introductory text, remove the phrase ''under paragraph (b) of this section'' and add in its place ''under paragraphs (b)(1) and (b)(2)(ii) of this section'';
■ d. Add paragraph (b)(5);
■ e. Add paragraph (h).

The additions read as follows:

§ 701.23 Purchase, sale, and pledge of eligible obligations.

* * * * *

(b) * * *

(2) *Purchase of obligations from a FICU.* A federal credit union that received a composite CAMEL rating of ''1'' or ''2'' for the last two (2) full examinations and maintained a net worth classification of ''well capitalized'' under Part 702 of this chapter for the six (6) immediately preceding quarters or, if subject to a risk-based net worth (RBNW) requirement under Part 702 of this chapter, has remained ''well capitalized'' for the six (6) immediately preceding quarters after applying the applicable RBNW requirement may purchase and hold the following obligations, provided that it would be empowered to grant them:

(i) *Eligible obligations.* Eligible obligations without regard to whether they are obligations of its members, provided they are purchased from a federally-insured credit union and the obligations are either:

(A) Loans the purchasing credit union is empowered to grant; or

(B) Loans refinanced with the consent of the borrowers, within 60 days after they are purchased, so that they are loans the purchasing credit union is empowered to grant;

(ii) *Eligible obligations of a liquidating credit union.* Eligible obligations of a liquidating credit union without regard to whether they are obligations of the liquidating credit union's members.

(iii) *Student loans.* Student loans provided they are purchased from a federally-insured credit union only;

(iv) *Real estate-secured loans.* Real estate-secured loans provided they are purchased from a federally-insured credit union only;

* * * * *

(5) *Grandfathered purchases.* Subject to safety and soundness considerations, a federal credit union may hold any of the loans described in paragraph (b)(2) of this section provided it was authorized to purchase the loan and purchased the loan before July 2, 2012.

* * * * *

(h) *Additional authority.* (1) A federal credit union may submit a written request to its regional director seeking expanded authority to purchase loans described in paragraph (b)(2) of this section, if it is not otherwise authorized by this section. The written request must include the following:

(i) A copy of the credit union's purchase policy;

(ii) The types of eligible obligations under paragraph (b)(2) of this section that the credit union seeks to purchase;

(iii) An explanation of the need for additional authority; and

(iv) An analysis of the credit union's prior experience with the purchase of eligible obligations.

(2) *Approval process.* A regional director will provide a written determination on a request for expanded authority within 60 calendar days after receipt of the request; however, the 60-day period will not begin until the requesting credit union has submitted all necessary information to the regional director. The regional director will inform the requesting credit union, in writing, of the date the request was received and of any additional documentation that the regional director requires in support of the request. If the regional director approves the request, the regional director will establish a limit on loan purchases as appropriate and subject to the limitations in this section. If the regional director does not notify the credit union of the action taken on its request within 60 calendar days of the receipt of the request or the receipt of additional requested supporting information, whichever

occurs later, the credit union may purchase loans it requested under paragraph (b)(2) of this section.

(3) *Appeal to NCUA Board.* A federal credit union may appeal any part of the determination made under this paragraph to the NCUA Board by submitting its appeal through the regional director within 30 days of the date of the determination.

§ 701.25 [Removed and Reserved]

■ 3. Remove and reserve § 701.25.

§ 701.32 [Amended]

■ 4. In § 701.32 amend paragraph (b)(1) by removing ''$1.5 million'' after the words ''federal credit union'' and adding in its place ''$3 million''.

■ 5. Amend § 701.36 by revising paragraph (b)(2) and removing paragraph (d) and redesignating paragraph (e) as paragraph (d):

The revision reads as follows:

§ 701.36 FCU ownership of fixed assets.

* * * * *

(b) * * *

(2) When a federal credit union acquires premises for future expansion, it must partially occupy the premises within a reasonable period, not to exceed three years, unless the credit union has acquired unimproved real property for future expansion. If a federal credit union has acquired unimproved real property to develop for future expansion, it must partially occupy the premises within a reasonable period, not to exceed six years. Premises are partially occupied when the credit union is using some part of the space on a full-time basis. The NCUA may waive this partial occupation requirement in writing upon written request. The request must be made within 30 months after the property is acquired.

* * * * *

PART 703—INVESTMENTS AND DEPOSIT ACTIVITIES

■ 6. The authority citation for part 703 continues to read as follows:

Authority: 12 U.S.C. 1757(7), 1757(8), 1757(15).

■ 7. In § 703.13, revise paragraph (d)(3) to read as follows:

§ 703.13 Permissible investment activities.

* * * * *

(d) * * *

(3) The investments referenced in paragraph (d)(2) of this section must mature under the following conditions:

(i) No later than the maturity of the borrowing repurchase transaction;

(ii) No later than thirty days after the borrowing repurchase transaction, unless authorized under § 703.20, provided the value of all investments purchased with maturities later than borrowing repurchase transactions does not exceed 100 percent of the federal credit union's net worth; or

(iii) At any time later than the maturity of the borrowing repurchase transaction, provided the value of all investments purchased with maturities later than borrowing repurchase transactions does not exceed 100 percent of the federal credit union's net worth and the credit union received a composite CAMEL rating of ''1'' or ''2'' for the last two (2) full examinations and maintained a net worth classification of ''well capitalized'' under part 702 of this chapter for the six (6) immediately preceding quarters or, if subject to a risk-based net worth (RBNW) requirement under part 702 of this chapter, has remained ''well capitalized'' for the six (6) immediately preceding quarters after applying the applicable RBNW requirement.

* * * * *

■ 8. Amend § 703.14 by adding paragraphs (i) and (j) to read as follows:

§ 703.14 Permissible investments.

* * * * *

(i) *Zero-coupon investments.* A federal credit union may only purchase a zero-coupon investment with a maturity date that is no greater than 10 years from the related settlement date, unless authorized under § 703.20 or otherwise provided in this paragraph. A federal credit union that received a composite CAMEL rating of ''1'' or ''2'' for the last two (2) full examinations and maintained a net worth classification of ''well capitalized'' under part 702 of this chapter for the six (6) immediately preceding quarters or, if subject to a risk-based net worth (RBNW) requirement under part 702 of this chapter, has remained ''well capitalized'' for the six (6) immediately preceding quarters after applying the applicable RBNW requirement, may purchase a zero-coupon investment with a maturity date that is no greater than 30 years from the related settlement date.

(j) *Commercial mortgage related security (CMRS).* A federal credit union may purchase a CMRS permitted by Section 107(7)(E) of the Act; and, pursuant to Section 107(15)(B) of the Act, a CMRS of an issuer other than a government-sponsored enterprise enumerated in Section 107(7)(E) of the Act, provided:

(1) The CMRS is rated in one of the two highest rating categories by at least one nationally-recognized statistical rating organization;

(2) The CMRS meets the definition of mortgage related security as defined in 15 U.S.C. 78c(a)(41) and the definition of commercial mortgage related security as defined in § 703.2 of this part;

(3) The CMRS's underlying pool of loans contains more than 50 loans with no one loan representing more than 10 percent of the pool; and

(4) The aggregate amount of private label CMRS purchased by the federal credit union does not exceed 25 percent of its net worth, unless authorized under § 703.20 or as otherwise provided in this subparagraph. A federal credit union that has received a composite CAMEL rating of ''1'' or ''2'' for the last two (2) full examinations and maintained a net worth classification of ''well capitalized'' under part 702 of this chapter for the six (6) immediately preceding quarters or, if subject to a risk-based net worth (RBNW) requirement under part 702 of this chapter, has remained ''well capitalized'' for the six (6) immediately preceding quarters after applying the applicable RBNW requirement, may hold private label CMRS in an aggregate amount not to exceed 50% of its net worth.

§ 703.16 [Amended]

■ 9. In § 703.16, remove paragraphs (b) and (d) and redesignate paragraphs (c), (e), and (f) as paragraphs (b), (c), and (d) respectively.

■ 10. In § 703.18, redesignate paragraph (b) as paragraph (c) and add new paragraph (b) read as follows:

§ 703.18 Grandfathered investments.

* * * * *

(b) A federal credit union may hold a zero-coupon investment with a maturity greater than 10 years, a borrowing repurchase transaction in which the investment matures at any time later than the maturity of the borrowing, or CMRS that cause the credit union's aggregate amount of CMRS from issuers other than government-sponsored enterprises to exceed 25% of its net worth, in each case if it purchased the investment or entered the transaction under the Regulatory Flexibility Program before July 2, 2012.

■ 11. Add § 703.20 to read as follows:

§ 703.20 Request for additional authority.

(a) *Additional authority.* A federal credit union may submit a written request to its regional director seeking expanded authority above the following limits in this part:

(1) Borrowing repurchase transaction maximum maturity mismatch of 30 days under § 703.13(d)(3)(ii).

(2) Zero-coupon investment 10-year maximum maturity under § 703.14(i), up to a maturity of no more than 30 years.

(3) CMRS aggregate limit of 25% of net worth under § 703.14(j), up to no more than 50% of net worth. To obtain approval for additional authority, the federal credit union must demonstrate three consecutive years of effective CMRS portfolio management and the ability to evaluate key risk factors.

(b) *Written request.* A federal credit union desiring additional authority must submit a written request to the NCUA regional office having jurisdiction over the geographical area in which the credit union's main office is located, that includes the following:

(1) A copy of the credit union's investment policy;

(2) The higher limit sought;

(3) An explanation of the need for additional authority;

(4) Documentation supporting the credit union's ability to manage the investment or activity; and

(5) An analysis of the credit union's prior experience with the investment or activity.

(c) *Approval process.* A regional director will provide a written determination on a request for expanded authority within 60 calendar days after receipt of the request; however, the 60-day period will not begin until the requesting credit union has submitted all necessary information to the regional director. The regional director will inform the requesting credit union, in writing, of the date the request was received and of any additional documentation that the regional director requires in support of the request. If the regional director approves the request, the regional director will establish a limit on the investment or activity as appropriate and subject to the limitations in this part. If the regional director does not notify the credit union of the action taken on its request within 60 calendar days of the receipt of the request or the receipt of additional requested supporting information, whichever occurs later, the credit union may proceed with its proposed investment or investment activity.

(d) *Appeal to NCUA Board.* A federal credit union may appeal any part of the determination made under paragraph (c) to the NCUA Board by submitting its appeal through the regional director within 30 days of the date of the determination.

PART 713—FIDELITY BONDS AND INSURANCE COVERAGE FOR FEDERAL CREDIT UNIONS

■ 12. The authority citation for part 713 continues to read as follows:

Authority: 12 U.S.C. 1761a, 1761b, 1766(a), 1766(h), 1789(a)(11).

■ 13. In § 713.6, revise paragraphs (a)(1) and (c) to read as follows:

§ 713.6 What is the permissible deductible?

(a)(1) The maximum amount of allowable deductible is computed based on a federal credit union's asset size and capital level, as follows:

Assets	Maximum deductible
$0 to $100,000	No deductible allowed.
$100,001 to $250,000	$1,000.
$250,000 to $1,000,000	$2,000.
Over $1,000,000	$2,000 plus 1/1000 of total assets up to a maximum of $200,000; for credit unions that have received a composite CAMEL rating of "1" or "2" for the last two (2) full examinations and maintained a net worth classification of "well capitalized" under part 702 of this chapter for the six (6) immediately preceding quarters or, if subject to a risk-based net worth (RBNW) requirement under part 702 of this chapter, has remained "well capitalized" for the six (6) immediately preceding quarters after applying the applicable RBNW requirement, the maximum deductible is $1,000,000.

* * * * *

(c) A federal credit union that has received a composite CAMEL rating of "1" or "2" for the last two (2) full examinations and maintained a net worth classification of "well capitalized" under part 702 of this chapter for the six (6) immediately preceding quarters or, if subject to a risk-based net worth (RBNW) requirement under part 702 of this chapter, has remained "well capitalized" for the six (6) immediately preceding quarters after applying the applicable RBNW requirement is eligible to qualify for a deductible in excess of $200,000. The credit union's eligibility is determined based on it having assets in excess of $1 million as reflected in its most recent year-end 5300 call report. A federal credit union that previously qualified for a deductible in excess of $200,000, but that subsequently fails to qualify based on its most recent year-end 5300 call report because either its assets have decreased or it no longer meets the net worth requirements of this paragraph or fails to meet the CAMEL rating requirements of this paragraph as determined by its most recent examination report, must obtain the coverage otherwise required by paragraph (b) of this section within 30 days of filing its year-end call report and must notify the appropriate NCUA regional office in writing of its changed status and confirm that it has obtained the required coverage.

PART 721—INCIDENTAL POWERS

■ 14. The authority citation for part 721 continues to read as follows:

Authority: 12 U.S.C. 1757(17), 1766, 1789.

■ 15. In § 721.3, redesignate paragraphs (b) through (l) as paragraphs (c) through (m) and add new paragraph (b) to read as follows:

§ 721.3 What categories of activities are preapproved incidental powers necessary or requisite to carry on a credit union's business?

* * * * *

(b) *Charitable contributions and donations.* Charitable contributions and donations are gifts you provide to assist others through contributions of staff, equipment, money, or other resources. Examples of charitable contributions include donations to community groups, nonprofit organizations, other credit unions or credit union affiliated causes, political donations, as well as donations to create charitable foundations.

* * * * *

PART 723—MEMBER BUSINESS LOANS

■ 16. The authority citation for part 723 continues to read as follows:

Authority: 12 U.S.C. 1756, 1757, 1757A, 1766, 1785, 1789.

■ 17. In § 723.1 revise paragraph (e) to read as follows:

§ 723.1 What is a member business loan?

* * * * *

(e) *Purchases of nonmember loans and nonmember loan participations.* Any interest a credit union obtains in a nonmember loan, pursuant to §§ 701.22 and 701.23(b)(2), under a Regulatory Flexibility Program designation before July 2, 2012 or other authority, is treated the same as a member business loan for purposes of this rule and the risk weighting standards under part 702 of this chapter, except that the effect of such interest on a credit union's aggregate member business loan limit will be as set forth in § 723.16(b) of this part.

PART 742—[REMOVED]

■ 18. Under the authority of 12 U.S.C. 1756 and 1766, the National Credit Union Administration removes part 742.

[FR Doc. 2012–13212 Filed 5–30–12; 8:45 am]

BILLING CODE 7535–01–P

NATIONAL CREDIT UNION ADMINISTRATION

12 CFR Part 741

RIN 3133–AE01

Loan Workouts and Nonaccrual Policy, and Regulatory Reporting of Troubled Debt Restructured Loans

AGENCY: National Credit Union Administration (NCUA).

ACTION: Final rule; limited extension of compliance date for certain requirements.

SUMMARY: NCUA is amending its regulations to require federally insured credit unions (FICUs) to maintain written policies that address the management of loan workout arrangements and nonaccrual policies for loans, consistent with industry practice or Federal Financial Institutions Examination Council (FFIEC) requirements. The final rule includes guidelines, set forth as an interpretive ruling and policy statement (IRPS) and incorporated as an appendix to the rule, that will assist FICUs in complying with the rule, including the regulatory reporting of troubled debt restructured loans (TDR loans or TDRs) in FICU Call Reports.

DATES: The effective date for this rule is July 2, 2012. The compliance date is extended to October 1, 2012 for the rule's requirements to adopt written policies addressing loan workouts and nonaccrual practices and to December 31, 2012 to collect nonaccrual status data.

FOR FURTHER INFORMATION CONTACT: Director of Supervision Matthew J. Biliouris and Chief Accountant Karen Kelbly, Office of Examination and Insurance at the above address or telephone: (703) 518–6360.

SUPPLEMENTARY INFORMATION:

I. Background

a. Why is NCUA issuing this rule?

In order to better serve members experiencing financial difficulties over the last several years and improve collectability, FICUs worked with members and offered sensible workout loans, including programs offered through the Obama Administration's ''Making Home Affordable Program''.[1] NCUA's existing reporting requirements creates practical challenges for the industry as the volume of workouts increased. To follow the NCUA 5300 Call Report (Call Report) instructions for reporting past due status on TDRs, many FICUs maintain separate, manual delinquency computations. To respond to feedback from the industry and in the spirit of reduced regulatory burden, the NCUA Board (Board) issued a Notice of Proposed Rulemaking (NPRM) in February. 77 FR 4927 (Feb. 1, 2012).

In the NPRM, the Board acknowledged the need to effectively balance appropriate loan workout programs with safety and soundness considerations. Such considerations can include the inability to identify deterioration in the quality of the loan portfolio and delayed loss recognition, in light of the high degree of relapse into past due status. The Board issued the NPRM with the goal of granting certain regulatory relief, instituting some countervailing controls, and clarifying regulatory expectations.

In the NPRM, the Board proposed four regulatory changes through an amendment to § 741.3 and the addition of proposed Appendix C to part 741. First, the NPRM proposed a requirement that FICUs have written policies addressing loan workouts and nonaccrual practices under § 741.3. Second, the NPRM proposed to standardize an industry-wide practice by requiring that FICUs cease to accrue interest on all loans at 90 days or more past due, subject to a few exceptions. Third, the NPRM proposed that FICUs maintain member business workout loans in a nonaccrual status until the FICU receives 6 consecutive payments under the modified terms. Finally, the NPRM proposed that FICUs calculate and report TDR loan delinquency based on restructured contract terms rather than the original loan terms. To that end, the Board noted that NCUA would modify the Call Report to reduce data collection to TDRs as defined by GAAP.

b. When will FICUs have to comply with the final rule?

The Board proposed that the final rule would go into effect 120 days after it was published in the **Federal Register** and require that FICUs adopt the required written lending policies by such date. The NPRM also stated that NCUA would closely time its adjustments to the Call Report requirements for reporting TDRs with the rule and stated a goal for the Call Report requirements to go into effect no later than the quarter ending December 31, 2012. The NPRM specifically sought comments on the proposed implementation dates.

In response to the NPRM, the Board received many varied comments on how it should approach implementation of the rule, appendix and NCUA's modification of the Call Report. One trade group urged NCUA to move forward with Call Report changes as soon as it adopted the rule, while a FICU supported the Call Report reporting requirements to become effective no later than December 31, 2012. One FICU commenter stated that the quick adoption of the proposed changes would have a profound effect on FICU personnel hours needed to perform the TDR reporting requirement and, therefore, requested implementation of the final rule by the end of the 2nd quarter of 2012. Likewise, another FICU stated that the December 31, 2012 report date would not give FICUs enough time to purchase software and perform a six-month due diligence review. The FICU noted that, while a new system can effectively capture new loan history, it will have serious challenges with systematically capturing existing loan history retrospectively for data previously tracked manually. The commenter

[1] The Making Home Affordable Program (MHA) was developed to help homeowners avoid foreclosure, stabilize the country's housing market, and improve the nation's economy. MHA includes such programs as the ''Home Affordable Refinance Program'' (HARP) and ''Home Affordable Modification Program'' (HAMP). Programs such as these further enable FICUs to provide workout loans to their members. For additional information regarding programs available through MHA see *http://www.makinghomeaffordable.gov/pages/default.aspx.*

requested a two-year timeframe to allow appropriate time for due diligence and full compliance.

One FICU and one league expressed concern that the proposed 120 days compliance timeframe would not be enough time if a FICU has to modify systems. The FICU stated there may be disparities in how various computer systems handle the 90-day nonaccrual policy, as well as the handling of accrued interest, reprogramming, and testing. The commenter suggested that NCUA set a firm, but reasonable, date for compliance. Several commenters raised concerns about the ability of small credit unions to revise or implement changes to their lending policies and systems. Four leagues requested that small credit unions be given extra time or transition period beyond the proposed 120 days. One league suggested that NCUA permit compliance within 120 days, but not require compliance for at least 180 days to accommodate small credit unions. Similarly, one trade group, on behalf of FICUs that are able to comply with the changes, urged NCUA to adopt the rule and make it effective as soon as possible. Yet the trade group also asked for additional time for smaller institutions to comply with the final rule. One FICU asked NCUA to adopt the rule as soon as possible with a 180-day transition period for implementation. One league requested a twelve-month implementation period.

After reviewing the various approaches suggested by the commenters, the Board has decided to make one provision of the final rule effective within 30 days of publication in the **Federal Register**, while delaying the compliance date of the other provisions. Under the final rule, FICUs will be required to calculate the past due status of workout loans consistent with loan contract terms, including amendments made through formal restructures as soon as the rule goes into effect on July 2, 2012. Data collections on the Call Report for the quarter ending June 30, 2012 will reflect revised TDR past due reporting. NCUA will begin collecting IRPS compliant data in the Call Report filing for quarter ending December 31, 2012. In order for FICUs to file the data related to loans placed in nonaccrual status in accordance with the final rule and IRPS for quarter ending December 31, 2012, FICUs must have their written nonaccrual and loan workout policies in place at the beginning of the quarter. The compliance date for adopting written loan policies and collecting nonaccrual information as discussed in Section III is October 1, 2012. FICUs, however, may adopt their policies and adjust their financial reporting systems as soon as is practicable after the rule's effective date, rather than waiting for the mandatory compliance date if they so choose.

II. Summary of Comments on the Proposed Rulemaking

The NPRM's comment period ended on March 2, 2012. NCUA received forty-five comment letters on the NPRM: thirty from FICUs, two from trade associations representing credit unions, ten from state credit union leagues, one from an accounting firm, one from an organization representing state credit union regulators, and one from a non-profit policy organization. Of the forty-five comments received, thirteen commenters supported the rulemaking generally, while thirty-one commenters offered some support for the rulemaking but objected to certain provisions or requested substantive revisions. One commenter questioned the purpose of the proposed rule. For the reasons discussed below, the Board adopts the amendments almost exactly as it proposed but, as requested by many commenters, provides some clarifications and excludes the proposed requirement that FICUs adopt aggregate limits in their loan workout and nonaccrual policies tied to net worth.

a. Written Loan Workout Policy and Monitoring Requirements

Thirteen FICUs, three leagues and the accounting firm supported the proposed rule's requirement that FICUs have a written loan workout policy combined with associated monitoring and controls. Most of these commenters stressed, however, that regulators must not review these policies from a standardized approach under the supervisory process. They urged regulators to afford a FICU an appropriate degree of flexibility based on the individuality of that FICU and the composition of its field of membership.

They argued that each loan modification should stand on its own merits, and that a FICU should be able to modify a loan if it is in the long term best interests of the member and the FICU without a ''one size fits all'' approach in the guidelines. One trade group and one league stated that, while FICUs should maintain loan workout policies, examiners should not expect a separate policy on TDRs. These commenters also stated that examiners should recognize that loan workout policies and practices must be commensurate with a FICU's size and complexity. One league requested that NCUA provide, at a minimum, an outline with suggestions of specific areas that examiners will expect to see addressed in policies. It also suggested that any requirements for a policy allow room for an individual's particular circumstance. In contrast, one industry trade group opposed a requirement that FICUs adopt loan workout or nonaccrual policies and advocated that NCUA issue guidance rather than a rule. It noted that many FICUs already engage in such a practice and already have invested in implementing software.

The Board continues to believe it is necessary to require a written loan workout policy. Because NCUA is relaxing its previous directives on past due calculations for TDRs and modifying the related Call Report data collections to reduce regulatory burden, the Board believes countervailing controls are necessary. It finds the final rule's requirement that FICUs adopt written loan workout and nonaccrual policies adequately addresses NCUA's supervisory interests. Furthermore, the Board notes the proposed IRPS clearly stated that a FICU's loan workout policy and practices should be ''commensurate with each credit union's size and complexity,'' in line with its broader risk mitigation strategies. 77 FR at 4934. By taking the approach in the NPRM that FICU management must design policies appropriate for their institutions, rather than setting forth ''bright line'' regulatory requirements or otherwise placing defined parameters on FICU policies, the Board acknowledges it is not appropriate to take a one-size fits all approach. As such, the final rule and IRPS continue to give a FICU's management the ability to establish institution-appropriate policies. In addition, the Board commits to providing NCUA's examiners with appropriate guidance for evaluating whether loan modifications made under a FICU's policy improves collectability.

Most commenters objected to the requirement that loan workout policies establish particular limits or benchmarks. Four commenters stated that the imposition of aggregate limits is unnecessary and could result in greater risk to FICUs by preventing them from making sound decisions that could result in future collectability. One commenter stated that setting aggregate limits could create the unintended consequence of a FICU treating members differently if the FICU approaches any such regulatory limit. Other commenters echoed similar concerns, stating that loan modifications should always be considered when they are in the best interests of the lender and the borrower, but that FICUs need flexibility in the current economic cycle. Failure to approve sound modifications simply because of a policy limit could increase risk of default and expose a FICU to reputation risk. Fourteen FICU commenters and three leagues specifically objected to tying loan modification program limits to a percentage of a FICU's net worth. One commenter stated that, while a limit might be appropriate for some FICUs, that same limit might not be the appropriate measure for others. Another FICU noted that its net worth declined during the recent severe economic conditions in its state. The FICU argued that, had the proposed limitation been in place, it would have reduced the FICU's ability to help members at a time when assistance was most needed. Another FICU noted that modifications are a risk mitigation strategy for loans already on a FICU's balance sheet, not a business strategy to incur additional risk.

The Board carefully considered the substantial comments on the NPRM's requirement that a FICU's loan workout policy include aggregate program limits set to a percentage of its net worth and agrees with the commenters that the proposed requirement could prevent a FICU from appropriately mitigating risk and assisting its members. 77 FR at 4930, 4934. The final IRPS does not include a requirement to place aggregate limits on a loan workout program as the Board proposed in the NPRM. As discussed in greater detail in Section III, NCUA will focus on a FICU's restructuring practices and whether its efforts have demonstrated an improvement in collectability of TDRs.

Two commenters suggested that, instead of a specified aggregate limit, the rule require FICU management to provide enhanced reporting on TDR activity to the FICU's board of directors. Another commenter suggested mandatory reporting to the FICU board on a regular basis. The Board agrees with these suggestions and has incorporated enhanced reporting requirements in the final rule. One commenter suggested continued reporting in Call Reports, including the number of times a loan has been modified in a 12-month period. The Board will consider this suggestion as it moves forward with its modifications to the Call Report. One commenter stated that ensuring proper documentation supporting a TDR and the borrower's ability to comply with the new terms best addresses concerns that a FICU is masking true performance and the past due status of its portfolio. The Board agrees with the commenter. As discussed in Section III, the final IRPS addresses the need for proper documentation and effective restructuring practices, preventing delayed loss recognition.

One FICU specifically commented on the proposal's requirement to limit the number of times a loan workout may be provided to a member over a period of time. The FICU stated that, while such a limit may eliminate the issue of masking problem loans, it also creates obstacles when there are legitimate reasons for multiple workouts. For example, as state and local governments and school districts have restricted spending, members endured layoffs and rounds of wage and hours cuts. As they have had to adjust their own budgets, many have asked their lender FICUs to revise terms of their workout loans. If a FICU's policy limits the number of times a workout loan can be modified or changed, these members will be adversely affected for no reason other than policy. Therefore, the commenter recommended that the rule be changed to allow workout loans to be modified any time a FICU can legitimately identify a reasonable change in the member's economic circumstances (i.e., income and other documentation should be required prior to making a change to a workout loan). The proposed IRPS in the NPRM includes a requirement that FICUs define eligibility requirements, including limits on the number of times an individual loan may be restructured, but these decisions as to limits are left to the discretion of the FICU when establishing its written policy. ''Loan workout arrangements should consider and balance the best interests of both the borrower and the credit union.'' 77 FR at 4934. The Board expects a FICU to evaluate the changed circumstances of an individual borrower with the need to improve collectability for the profitable operation of the institution. It is the FICU's responsibility to craft loan workout policies that strike that balance. NCUA will then measure the success of the policy based on the FICU's ability to collect TDRs. The final IRPS, therefore, retains the requirement to establish eligibility requirements as proposed in the NPRM.

b. Loan Nonaccrual Policy for All Loans and Restoration to Accrual for Loans Other Than Member Business Loan (MBL) Workout Loans

Four FICUs and two leagues supported the proposed requirement that FICUs maintain nonaccrual policies that address the discontinuance of interest accrual for loans past due by 90 days or more and the requirements for returning such loans, including MBLs, to accrual status. The commenters noted that the proposed nonaccrual policy has long been the practice of FICUs and is supported by current institution interest management systems, so it would not present additional unwarranted work for FICUs. In addition, an accounting firm and two FICUs found the proposal consistent with industry practice and FFIEC requirements. They supported the proposed rule's effort to formalize the practice of placing loans on nonaccrual status when they are 90 days past due. One league argued that compliance with the proposal would require FICUs to change loan tracking systems, thereby incurring significant programming costs. The final rule and IRPS retain the requirement for a written policy addressing nonaccrual practices as proposed in the NPRM, with a few clarifications as discussed below.

One FICU objected to a blanket requirement that interest may not accrue on loans that are 90 days or more past due. The commenter stated that if a loan is performing at a level agreed to by the FICU and debtor, and it can be reasonably demonstrated that full recovery of the balance owed is likely, continuing to accrue interest due is appropriate and should be allowed. The commenter incorrectly characterized the requirement as a blanket prohibition. The proposed IRPS states that a FICU may not accrue interest on a loan in default for a period of 90 days or more ''unless the loan is both *well secured* and in the *process of collection.*'' *Id.* The final IRPS retains this provision.

One FICU expressed concern that the proposal places an undue burden on individual small accounts and requested that the final rule exclude accounts under $25,000 from the nonaccrual policy. The commenter also suggested that NCUA consider using a more individualized index to determine a nonaccrual amount based on the total TDR classified loan balance. The commenter contended this approach would take far less time to calculate, and be more accurate, than under the current process. The Board does not agree with the commenter's rationale. The Board believes that a standard policy applicable to all loans in nonaccrual status, other than typically riskier and higher-dollar business loans, ensures consistency as the policy is employed by FICUs and reviewed by examiners.

One industry trade group did not support a requirement that FICUs must adopt nonaccrual procedures because they are not required by GAAP or the Federal Credit Union Act. This commenter agreed, however, that the proposed IRPS' restoration to accrual status for loans, excluding MBL workouts, is consistent with GAAP. Two FICUs and two leagues also questioned the necessity of a formal regulation for this requirement because, for years, it has been the industry standard to terminate the accrual of interest when a loan is 90 days delinquent. The commenters argued that the proposal is redundant and it is therefore unnecessary to include this standard practice in a regulation. They contend that NCUA could better handle exceptions to this nonaccrual approach through the examination and supervision process. While recognizing the practice has been longstanding in the industry, the Board believes that memorializing the practice as a rule, ensures ongoing, consistent and appropriate income recognition for loans that are past due by 90 days or more. In addition, the rule enables the agency to enforce noncompliance if necessary.

One FICU and one league stated there is great disparity in FICUs' computer systems in dealing with the 90-day policy, specifically that some FICUs time the policy to 90 days while others time the policy to 91 or more days. The FICU commenter noted a difference in practice as to whether accrued interest is reversed when it goes into nonaccrual status or if there actually is no additional interest accrued to the general ledger prospectively. The final IRPS clarifies that the nonaccrual policy applies when the loan is 90 days or more past due. In response to the FICU commenter, the final IRPS also clarifies that when accrued interest is reversed, the reversed interest cannot be subsequently restored but can only be recognized as income if it is collected in cash or cash equivalents, and that there is no additional accrual until restoral to accrual conditions are met. This approach is consistent both with GAAP principles governing interest recognition on loans and longstanding banking industry practice.

One league requested that the final rule clarify that placing a loan on nonaccrual status does not change the loan agreement or the obligations between the borrower and the FICU, unless and until the parties reach express agreement on modifying the original loan terms. The commenter expressed concern that the final rule will be perceived as forgiveness of interest or principal or any type of right to a modification conferred to the borrower. To address this concern, the final IRPS includes a footnote to make clear that the accounting procedure to place a loan on nonaccrual status has no impact on the borrower's contractual obligation to the FICU.

c. Restoration of Member Business Workout Loans to Accrual

Thirteen FICUs and eight leagues stated they saw no justification for treating MBLs differently than consumer/residential loans. They objected to the proposal's continuation of the current requirement that MBLs remain in nonaccrual status until a FICU receives six consecutive payments under modified loan terms. One commenter questioned the application of the proposal to all MBLs given that not all MBLs are commercial real estate loans. Two FICUs stated that this provision contradicts GAAP. Two commenters misunderstood the Board's remedy to past due reporting of all loans, including MBLs, and argued that the proposal's treatment of MBLs will artificially inflate delinquency. The differentiation the rule makes between MBLs and other loans regards provisions for restoration to accrual status, not delinquency reporting. Past due reporting will now be consistent with loan contract terms for all loans including MBLs. One commenter stated that, in general, MBL portfolios are comprised of a pool of individually unique loans with different collateral terms and repayment capabilities based on the financial situation and creditworthiness of the borrower/guarantor. As such, the commenter felt it was inappropriate to establish a six-month standard that would uniformly apply to a pool of individually unique loans. The commenter argued that the determination to place an MBL back into accrual status should be based on the individual financial circumstances of the borrower rather than an arbitrary period of time. One industry trade group also strongly urged NCUA to provide consistent relief for consumer loan and MBL workouts. It stated that the proposal perpetuates an unnecessary obstacle for FICUs to accommodate business members. Another trade group opposed the proposed treatment of MBLs because it is not required by the Federal Credit Union Act or GAAP. One FICU, six leagues, and one trade group stated that the tracking of MBLs as proposed would continue the burden of manually tracking these loans, thus imposing an additional barrier to making MBLs.

The Board considered the commenters' concerns but retained the proposed provisions for the restoration of MBL workout loans to accrual status in the final rule. In drafting the NPRM, NCUA weighed requiring identical treatment of both consumer and MBL workouts, i.e., the FICU would need to demonstrate a period of member repayment performance of six consecutive payments before the return to accrual status. In the interest of providing FICUs reduced burden without undue increased supervisory risk, the Board limited the more stringent requirement to only MBL workout loans. The Board's decision to retain the NPRM's proposed requirements for restoring MBL workout loans to accrual status is threefold: (1) The principle forming the basis for the provision is found in GAAP; (2) NCUA has previously joined the other federal regulators in advancing this provision in multiple interagency policy issuances, and (3) the requirement is a longstanding accepted banking practice.

One commenter encouraged NCUA to specifically define ''consecutive payment'' or give FICUs the authority to define the term in loan workout policies. Similarly, another FICU suggested that a payment made within a 30-day window of the due date (i.e., no late payments) be considered consecutive. This commenter also asked for clarification on what constitutes a payment for this purpose (e.g., principal and interest, principal only, or interest only) to ensure consistent reporting among FICUs. To clarify, a FICU is required to use the Cash Basis method of income recognition in GAAP until the borrower makes six consecutive timely payments of *principal and interest* consistent with the loan contract terms. The Board has clarified in the final IRPS that repayment performance involves timely payments of principal and interest under the restructured loan's terms.

One FICU, while agreeing with the proposal's requirement for maintaining certain MBLs in nonaccrual status for safety and soundness reasons, objected to extending the policy to multi-family residential mortgages. The commenter suggested that loans secured by 1–4 family residential properties, which fall into NCUA's MBL definition for other purposes, follow the proposal's non-MBL requirements for restoration to accrual status.

One FICU offered a slight modification to the proposed rule by expanding it to ''greater than 90 days and/or 3 months past due.'' It argued that many FICUs currently label internal reports as ''90 day,'' but upon a closer analysis of the actual technical format of FICUs' core processors, some FICUs would change the label to ''3 months.'' The final rule and IRPS maintain the uniform standard of 90 days or more.

One FICU requested clarification that MBL workout loans on nonaccrual status would not be considered delinquent for reporting purposes if the borrowers have made payments conforming to a loan workout but have not completed the 6-month period to resume accruals. The Board notes that past due status and nonaccrual are separate elements. The final IRPS, as proposed, is clear that past due status is remedied at the time of restructure regardless of the nonaccrual requirement.

One FICU requested that NCUA clarify its ''broad'' statement in the guidance that ''in no event should the credit union authorize additional advances to finance unpaid interest and fees,'' or eliminate the language altogether. The commenter stated that a FICU could interpret this language to suggest that the payment of a third-party fee could not be added to the collectible loan balance when attempting to recover losses. The commenter stated that its ability to capitalize interest at the point of restructure is an important tool in providing solutions to troubled borrowers. By mandating the acceptance of greater losses, NCUA would be inadvertently increasing risk in the area of safety and soundness, and possibly eliminating a viable member solution by ultimately creating too great a loss. The Board agrees such third-party fees should not hinder sound restructure decisions. Accordingly, the final IRPS includes new language to clarify that, while a FICU cannot make additional advances to the borrower to finance unpaid interest and credit union fees, it may make advances to cover third-party fees exclusive of credit union commissions, such as forced place insurance or property taxes.

d. Regulatory Reporting of Workout Loans, Including TDRs

Thirteen FICUs, an accounting firm, a non-profit consumer advocate, the state supervisory organization, eight leagues, and two industry trade groups supported the elimination of the current requirement to track and report TDRs as delinquent until six consecutive payments. Several commenters noted the change is a needed improvement, as the current reporting requirement has been problematic for many FICUs and an obstacle to helping members. The consumer advocate stated that by moving to more commonsense reporting, the proposal eliminates a disincentive for a FICU to consider TDRs, which in turn will result in fewer foreclosures. One FICU commenter also stated that the current requirements have been quite cumbersome and contrary in purpose to the FICU's efforts to keep members in their homes and avoid unnecessary foreclosure actions.

Several commenters believed that NCUA should enable FICUs to perform appropriate loan restructurings without a reporting treatment that has a chilling effect on this essential business decision during a period of economic downturn, particularly in hard hit states. Two commenters stated that FICUs overstate their true delinquencies under the current reporting process. One commenter stated that if institutions follow sound workout loan policies in which the borrower has a better capability and willingness to repay, then the TDR should be treated as performing under the new terms of the loan agreement. To pretend a loan is delinquent for six months based on the original past due date distorts the true delinquency of loans in the portfolio. One commenter noted that the overstatement of delinquencies causes unnecessary concern with counterparties and creates an ''apples to oranges'' comparison with other financial institutions because banks do not report TDRs as delinquent.

In support of the proposal, one FICU and one league noted that FICUs have developed elaborate tracking systems. They stated, however, that dual reporting systems have resulted in different financial reporting for internal and audited financial statements from that used in Call Reports. These differences have resulted in confusion. One of these commenters suggested that the new guidance caution FICUs that, when modifying loans and removing them from delinquency status, documentation of the borrower's ability to pay under the modified terms should include a thorough analysis of recent past payment performance with strong consideration of the immediately preceding three months. This commenter suggested that the guidance should limit to two the number of times during a 12-month period that a loan may be formally modified with a reset of the delinquency counters. This limitation would allow for tracking (without dual reporting) and prevent FICUs from masking true delinquency through continuous modifications. The commenter stated that data tracking should focus on: (1) Current levels of delinquency under restructured loan terms; (2) number and dollar amount of new TDRs modified during the quarter/year; (3) number and amount of current TDRs in the portfolio and reserves in the ALLL for TDRs; and (4) number and dollar amount of TDRs currently in the portfolio that have been formally restructured where the delinquency counters have re-set more than once during the last 12-month period to identify loans that have been rolled. The Board will consider these suggestions when it modifies the Call Report.

One FICU recommended that the final rule impose stricter monitoring and reporting of TDRs. It offered one example, which is a requirement for FICUs to track and report TDRs that are 30 days delinquent under the restructured terms.

Many commenters noted confusion in the industry and among examination staff about what makes a modified loan a TDR. Commenters suggested that NCUA refrain from using ''workout loan'' and ''TDR'' interchangeably, stating that all workout loans are not TDRs. They recommended that the proposal be restricted to TDRs to avoid confusion. Another commenter requested that, if the term ''workouts'' has any applicability in the final rule, a definition should clarify the materiality or significance of the loan term changes before the loan is deemed a ''workout.'' Two commenters stated that NCUA's definition of ''TDR'' is not consistent with FASB and suggested that NCUA review FASB Accounting Standards Update No. 2011–02, ''A Creditor's Determination of Whether a Restructuring Is a Troubled Debt Restructuring'' for clarification. One FICU and a league asked NCUA to consider detailed standards for FICUs and examiners to determine which loan modifications qualify as TDRs. Similarly, one FICU noted that the proposal shifts documentation requirements from TDRs to workout loans. It further noted that GAAP allows for some workout loans to be immaterial and non-reportable as TDRs if they satisfy ''insignificant'' criteria. The commenter, therefore, suggested that the rule apply only to TDRs and not to workout loans that do not meet the materiality component of GAAP. The Board plans to direct staff to develop supervisory guidance to examiners that will incorporate current agency regulatory and examination approaches and address many of these areas that have caused confusion in implementation. Staff will consider commenters concerns in drafting the supervisory guidance. The supervisory guidance will be provided to the credit union industry as well. However, the Board has determined the final rule language will continue to incorporate both the term ''TDR'' and the broader term ''workout'' in the final rule, both of which are defined in the IRPS glossary.

Three leagues, one trade group, and two FICUs objected to the proposal's statement ''that in an economic downturn absent contrary supportable information workout loans are TDRs.'' The commenters stated that this language only perpetuates confusion about what constitutes a TDR and is inconsistent with the definition of TDR in GAAP. One commenter stated that economic climate should not be the barometer of how a TDR is defined. Another commenter asked NCUA to address the definition of ''economic downturn'' and ''contrary supportable information,'' as well as what happens to modified loans in an environment that is not an economic downturn. One league urged NCUA to ensure that its glossary definitions are consistent with GAAP and to eliminate the ''economic downturn'' language and simply adopt the GAAP definition of TDR. The Board notes that in the NPRM, the proposed IRPS explicitly stated that ''[u]nder this IRPS, TDR loans are as defined in generally accepted accounting principles (GAAP) and the Board does not intend through this policy to change the Financial Accounting Standards Board's (FASB) definition of TDR in any way.'' 77 FR at 4933. Furthermore, it tracked GAAP in defining TDR in the glossary. The NPRM also urged FICUs to consider FASB clarifications in their recently revised, Accounting Standards Update No. 2011–02 (April 2011) to the FASB Accounting Standards Codification entitled, Receivables (Topic 310), ''A Creditor's Determination of Whether a Restructuring is a Troubled Debt Restructuring.'' The Board believes it is clear that the rule's focus is on restructures that meet the GAAP definition of TDR. When a FICU works with members in financial difficulty and grants term concessions as described in GAAP, the FICU will have TDRs to report in its regulatory reports. Working with members is consistent with its mission. Particularly in downward economic cycles, the need to work with members increases, thus the increase in restructuring strategies to serve members. As such, the Board acknowledges the value of TDRs. If a FICU enters into TDR arrangements that improve the collectability of loans, properly recognizes loan losses, and restores the loans to accrual status, the FICU has met its mission and its regulatory reporting burden. Risk is mitigated, achieving a goal desired by both NCUA and the FICU.

Two leagues and one trade group requested that the final rule include additional guidance, consistent with GAAP, on impairment testing and recognition requirements. Impairment testing is beyond the scope of this rulemaking, the Board refers to IRPS 02–1, ''Allowance for Loan and Lease Losses Methodologies and Documentation for Federally Insured Credit Unions,'' and NCUA's Accounting Bulletin No. 06–01 (December 2006) that transmits the 2006 Interagency ALLL Policy Statement for further information.

III. Final Rule and IRPS

a. Section 741.3, Lending Policies

The final rule amends § 741.3(b)(2) to require FICUs to adopt policies that govern loan workout arrangements and nonaccrual practices. The rule specifically requires that a FICU's written nonaccrual standards include the discontinuance of interest accrual on loans that are past due by 90 days or more and requirements for returning such loans, including MBLs workouts, to accrual status.

To set NCUA's supervisory expectations and assist FICUs in complying with the amendments to § 741.3(b)(2), the final rule includes an appendix to Part 741. The appendix thoroughly addresses the loan workout account management and reporting standards FICUs must implement in order to comply with the rule. It also explains how FICUs report their data collections related to TDRs on Call Reports. The contents of the appendix are described in detail below.

b. Appendix C to Part 741, Interpretive Ruling and Policy Statement on Loan Workouts, Nonaccrual Policy, and Regulatory Reporting of Troubled Debt Restructured Loans

1. Written Loan Workout Policy and Monitoring Requirements

The Board recognizes loan workouts can be used to help borrowers overcome temporary financial difficulties, such as loss of job, medical emergency, or change in family circumstances like loss of a family member. The Board further acknowledges that the lack of a sound workout policy can mask the true performance and past due status of the loan portfolio. Accordingly, the final rule requires the FICU board and management to adopt and adhere to an explicit written policy and standards that control the use of loan workouts, and establish controls to ensure the policy is consistently applied. The loan workout policy and practices should be commensurate with each credit union's size and complexity, and must be in line with the credit union's broader risk mitigation strategies.

The policy must define eligibility requirements (i.e., under what conditions the FICU will consider a loan workout), including establishing limits on the number of times an individual loan may be modified.[2] The policy must ensure the FICU makes loan workout decisions based on the borrower's renewed willingness and ability to repay the loan. In addition, the policy must establish sound controls to ensure loan workout actions are appropriately structured, including a prohibition against any authorizations of additional advances to finance unpaid interest and credit union fees. The final IRPS does provide that the policy may allow a FICU to make advances to cover third-party fees, such as force-placed insurance or property taxes. The FICU, however, cannot finance any related commissions it may receive from the third party.

Furthermore, the Board believes loan workouts should be adequately controlled and monitored by the board of directors and management, and therefore requires the decision to re-age, extend, defer, renew, or rewrite a loan, like any other revision to contractual terms, be supported by the FICU's management information systems. Sound management information systems are able to identify and document any loan that is re-aged, extended, deferred, renewed, or rewritten, including the frequency and extent such action has been taken. Appropriate documentation typically shows that the FICU's personnel communicated with the borrower, the borrower agreed to pay the loan in full, and the borrower has the ability to repay the loan under the new terms.

NCUA is concerned, however, about restructuring activity that pushes existing losses into future reporting periods without improving the loan's collectability. The final IRPS includes a provision notifying FICUs that if they engage in restructuring activity on a loan that results in restructuring a loan more often than once a year or twice in five years, examiners will have higher expectations for the documentation of the borrower's renewed willingness and ability to repay the loan. Examiners will ask FICUs to provide evidence that their policy of permitting multiple restructurings improve collectability.

In developing a written policy, the FICU board and management may wish to consider similar parameters as those established in the FFIEC's ''Uniform Retail Credit Classification and Account Management Policy'' (FFIEC Policy). 65 FR 36903 (June 12, 2000). The FFIEC

[2] Broad based credit union programs commonly used as a member benefit and implemented in a safe and sound manner limited to only accounts in good standing, such as Skip-a-Pay programs, are not intended to count toward these limits.

Policy sets forth specific limitations on the number of times a loan can be re-aged (for open-end accounts) or extended, deferred, renewed or rewritten (for closed-end accounts). Additionally, LCU 09–CU–19, ''Evaluating Residential Real Estate Mortgage Loan Modification Programs,'' outlines policy requirements for real estate modifications. Those requirements remain applicable to real estate loan modifications but could be adapted in part by the FICU in its written loan workout policy for other loans.

The Board does not intend for these minimum requirements to be an all inclusive list, rather they provide a basic framework within which to establish a sound loan workout program.

2. Regulatory Reporting of Workout Loans Including TDR Past Due Status

The Board recognizes that loan workouts that qualify under GAAP as TDRs require special financial reporting considerations. The final IRPS mandates that the past due status of all loans should be calculated consistent with loan contract terms, including amendments made to loan terms through a formal restructure. The IRPS eliminates the current, dual, and often manual delinquency tracking burden on FICUs managing and reporting TDR loans, while instituting a nonaccrual policy on TDR loans apart from past due status. The Board will modify the Call Report instructions accordingly.

Additionally, the final IRPS institutes revised Call Report data collections related to loan workouts eliminating much of the current data collections on the broad category ''loan modifications,'' focusing data collection on TDR loans. The Board will add additional data elements as necessary to effectively monitor and measure TDR activity and corresponding risk to the NCUSIF. This will assist national and field examination and supervision staff both to detect the level of activity and possible overuse of reworking a nonperforming loan multiple times without improving overall collectability, and will ensure income recognition is appropriate.

3. Loan Nonaccrual Policy

Generally, NCUA has required,[3] and it has become accepted credit union practice, to cease accruing interest on a loan when it becomes 90 days or more past due. The existing approach is referenced in various letters and publications but currently is not memorialized or enforceable through any statute or regulation. The final rule and IRPS require a FICU to adopt written nonaccrual policies that specifically address the discontinuance of interest accrual on loans past due by 90 days or more, as well as the requirements for returning such loans (including member business loan workouts) to accrual status.

Nonaccrual Status

The final IRPS specifies when FICUs must place loans in nonaccrual status, including the reversal of previously accrued but uncollected interest, sets the conditions for restoration of a nonaccrual loan to accrual status, and discusses the criteria under GAAP for Cash or Cost Recovery basis of income recognition. FICUs may not accrue interest on any loan upon which principal or interest has been in default for a period of 90 days or more, unless the loan is both ''well secured'' and ''in the process of collection.'' Additionally, FICUs must place loans in nonaccrual status if maintained on a Cash (or Cost Recovery) basis because of deterioration in the financial condition of the borrower, or for which payment in full of principal or interest is not expected. The IRPS also addresses the treatment of cash interest payments received during periods of loan nonaccrual and prohibits the restoration of previously reversed or charged-off accrued, but uncollected, interest applicable to any loan placed in nonaccrual status.

Restoration to Accrual Status (not Including Member Business Loan Workouts)

The final IRPS sets forth specific parameters for returning a nonaccrual loan to accrual.

A nonaccrual loan may be returned to accrual status when:

- Its past due status is less than 90 days, GAAP does not require it to be maintained on the Cash or Cost Recovery basis, and the credit union is plausibly assured of repayment of the remaining contractual principal and interest within a reasonable period;
- When it otherwise becomes well secured and in the process of collection; or
- The asset is a purchased impaired loan and it meets the criteria under GAAP for accrual of income under the interest method specified therein.

In restoring all loans to accrual status, if any interest payments received while the loan was in nonaccrual status were applied to reduce the recorded investment in the loan the application of these payments to the loan's recorded investment must not be reversed (and interest income must not be credited). Likewise, accrued but uncollected interest reversed or charged off at the point the loan was placed on nonaccrual status cannot be restored to accrual; it can only be recognized as income if collected in cash or cash equivalents from the member.

Restoration to Accrual Status on Member Business Loan Workouts

The Board recognizes there are unique circumstances governing the restoration of accrual for member business loan workouts and has set forth a separate policy in the proposal. This policy is largely derived from the ''Interagency Policy Statement on Prudent Commercial Real Estate Loan Workouts'' that NCUA and the other financial regulators issued on October 30, 2009.[4] The final IRPS requires a formally restructured member business loan workout to remain in nonaccrual status until the FICU can document a current credit evaluation of the borrower's financial condition and prospects for repayment under the revised terms. The evaluation must include consideration of the borrower's sustained historical repayment performance for a reasonable period prior to the date on which the loan is returned to accrual status.

A sustained period of repayment performance would be a minimum of six consecutive timely payments under the restructured loan's terms of principal and interest in cash or cash equivalents. In returning the member business workout loan to accrual status, sustained historical repayment performance for a reasonable time prior to the restructuring may be taken into account. Such a restructuring must improve the collectability of the loan in accordance with a reasonable repayment schedule and does not relieve the FICU from the responsibility to promptly charge off all identified losses.

4. Glossary

The final section of the IRPS is a glossary of terms used throughout.

To assist commenters in understanding existing agency guidance, the following illustration is provided:

[3] The policy was discussed in an obsolete version of the NCUA Accounting Manual for FCUs, last published in June 1995.

[4] See *Interagency Policy Statement on Prudent Commercial Real Estate Loan Workouts* (October 30, 2009) transmitted by Letter to Credit Unions No. 10–CU–07, and available at *http://www.ncua.gov.*

SUMMARY OF SOURCE GUIDANCE RELATED TO LENDING AND LOAN MODIFICATIONS

Source of supervisory guidance	Consumer lending	Member business lending
Existing Recent Supervisory Guidance on Lending and/or Loan Modifications.	Letter to Credit Union 11–CU–01, *Residential Mortgage Foreclosure Concerns,* (January 2011) *http://www.ncua.gov.* Letter to Credit Unions 09–CU–19, *Evaluating Residential Real Estate Mortgage Loan Modification Programs,* (September 2009) *http://www.ncua.gov.* Federal Financial Regulatory Agencies Issue Statement In Support of the *"Making Home Affordable" Loan Modification Program,*" (March 2009) *http://www.ncua.gov.* *Statement on Loss Mitigation Strategies for Servicers of Residential Mortgages,* (September 2007) *http://www.ncua.gov.*.	Letter to Credit Unions 10–CU–07, *Commercial Real Estate Loan Workouts,* transmitting *Interagency Policy Statement on Prudent Commercial Real Estate Loan Workouts,* (June 2010), and Enclosure *http://www.ncua.gov* Letter to Credit Unions 10–CU–02, *Current Risks in Business Lending and Sound Risk Management Practices,* (February 2010) *http://www.ncua.gov.*
Written Policy Requirement on Frequency of Modifications.	Final IRPS, Appendix C of Part 741	Final IRPS, Appendix C of Part 741 and Letter to Credit Unions 10–CU–07, *Commercial Real Estate Loan Workouts,* transmitting *Interagency Policy Statement on Prudent Commercial Real Estate Loan Workouts,* (June 2010) and Enclosure *http://www.ncua.gov.*
Nonaccrual	Final IRPS, Appendix C of Part 741.	
Delinquency	Final IRPS, Appendix C of Part 741.	
Allowance for Loan and Lease Losses.	IRPS 02–3, *Allowance for Loan and Lease Losses Methodologies and Documentation for Federally-Insured Credit Unions (May 2002), http://www.ncua.gov.* *2006 Interagency ALLL Policy Statement transmitted by Accounting Bulletin 06–1 (December 2006), http://www.ncua.gov.*	
Charge-offs	Letter to Credit Unions No. 03–CU–01, *Loan Charge-off Guidance* (January 2003), and its Enclosure, *http://www.ncua.gov.*	

IV. Regulatory Procedures

a. Regulatory Flexibility Act

The Regulatory Flexibility Act requires NCUA to prepare an analysis to describe any significant economic impact agency rulemaking may have on a substantial number of small credit unions, defined as those under ten million dollars in assets. This rule tightens loan account management processes that should already be in place in FICUs. While FICUs are required to have policies that address loan management protocols, the final rule and IRPS set additional parameters that are consistent with existing best practices and federal banking regulators' policies. NCUA has determined this final rule will not have a significant impact on a substantial number of small credit unions so NCUA is not required to conduct a Regulatory Flexibility Analysis.

b. Paperwork Reduction Act

The Paperwork Reduction Act of 1995 (PRA) applies to rulemakings in which an agency by rule creates a new paperwork burden on regulated entities or modifies an existing burden. 44 U.S.C. 3507(d); 5 CFR part 1320. For purposes of the PRA, a paperwork burden may take the form of either a reporting or a recordkeeping requirement, both referred to as information collections. As required, NCUA has applied to the Office of Management and Budget (OMB) for approval of the information collection requirement described below.

The final rule contains an information collection in the form of a written policy requirement. Any FICU making loan workout arrangements that assist borrowers must have a written policy to govern this activity. FICUs will only need to modify current policies to include any additional parameters established in the rule. It is therefore NCUA's view that implementing this type of policy will create minimum burden to credit unions. The parameters established within the rule and IRPS are usual and customary operating practices of a prudent financial institution. In the proposed rule, NCUA estimated it should take a FICU an average of 8 hours to modify current policies to comply with the parameters set forth in the proposed IRPS. Therefore, the total initial burden imposed to 7,250 FICUs for modifying the policies is approximately 58,000 hours. NCUA further estimated a FICU spends on average 15 minutes per month manually calculating and reporting past due status on each TDR loan. This policy eliminates this requirement. Per the September 30, 2011, Call Report, FICUs have 150,453 TDR loans outstanding. Eliminating this reporting requirement therefore results in an annual savings of 451,359 hours. Thus, on net, this policy results in a substantial hours (393,359 annually) reduction of regulatory burden.

OMB assigned No. 3133–XXXX to this rulemaking.

c. Small Business Regulatory Enforcement Fairness Act

The Small Business Regulatory Enforcement Fairness Act of 1996 (Pub. L. 104–121) provides generally for congressional review of agency rules. A reporting requirement is triggered in instances where NCUA issues a final rule as defined by Section 551 of the Administrative Procedure Act. 5 U.S.C. 551. The Office of Management and Budget has determined that this rule is not a major rule for purposes of the Small Business Regulatory Enforcement Fairness Act of 1996.

d. Executive Order 13132

Executive Order 13132 encourages independent regulatory agencies to consider the impact of their regulatory actions on state and local interests. NCUA, an independent regulatory agency as defined in 44 U.S.C. 3502(5), voluntarily complies with the executive order to adhere to fundamental federalism principles. This final rule applies to all FICUs but will not have a substantial direct effect on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government. NCUA has determined that this rule does not constitute a policy that has federalism implications for purposes of the executive order.

e. Assessment of Federal Regulations and Policies on Families

NCUA has determined that this final rule will not affect family well-being within the meaning of Section 654 of the Treasury and General Government Appropriations Act, 1999, Public Law 105–277, 112 Stat. 2681 (1998).

List of Subjects in 12 CFR Part 741

Credit unions, Reporting and recordkeeping requirements.

By the National Credit Union Administration Board on May 24, 2012.

Mary F. Rupp,

Secretary of the Board.

For the reasons discussed above, NCUA amends 12 CFR part 741 as follows:

PART 741—REQUIREMENTS FOR INSURANCE

■ 1. The authority citation for part 741 continues to read:

Authority: 12 U.S.C. 1757, 1766(a), 1781–1790 and 1790d; 31 U.S.C. 3717.

■ 2. In § 741.3, revise paragraph (b)(2) to read as follows:

§ 741.3 Criteria.

* * * * *

(b) * * *

(2) The existence of written lending policies, including adequate documentation of secured loans and the protection of security interests by recording, bond, insurance or other adequate means, adequate determination of the financial capacity of borrowers and co-makers for repayment of the loan, adequate determination of value of security on loans to ascertain that said security is adequate to repay the loan in the event of default, loan workout arrangements, and nonaccrual standards that include the discontinuance of interest accrual on loans past due by 90 days or more and requirements for returning such loans, including member business loans, to accrual status.

* * * * *

■ 3. Add Appendix C to read as follows:

Appendix C to Part 741—Interpretive Ruling and Policy Statement on Loan Workouts, Nonaccrual Policy, and Regulatory Reporting of Troubled Debt Restructured Loans

This Interpretive Ruling and Policy Statement (IRPS) establishes requirements for the management of loan *workout* [1] arrangements, loan nonaccrual, and regulatory reporting of *troubled debt restructured loans* (herein after referred to as TDR or TDRs).

This IRPS applies to all federally insured credit unions.

Under this IRPS, TDR loans are as defined in *generally* accepted accounting principles (GAAP) and the Board does not intend through this policy to change the Financial Accounting Standards Board's (FASB) definition of TDR in any way. In addition to existing agency policy, this IRPS sets NCUA's supervisory expectations governing loan workout policies and practices and loan accruals.

Written Loan Workout Policy and Monitoring Requirements [2]

For purposes of this policy statement, types of workout loans to borrowers in financial difficulties include *re-agings,* extensions, deferrals, renewals, or rewrites. See the Glossary entry on ''workouts'' for further descriptions of each term. Borrower retention programs or *new loans* are not encompassed within this policy nor considered by the Board to be workout loans.

Loan workouts can be used to help borrowers overcome temporary financial difficulties, such as loss of job, medical emergency, or change in family circumstances like loss of a family member. Loan workout arrangements should consider and balance the best interests of both the borrower and the credit union.

The lack of a sound written policy on workouts can mask the true performance and *past due* status of the loan portfolio. Accordingly, the credit union board and management must adopt and adhere to an explicit written policy and standards that control the use of loan workouts, and establish controls to ensure the policy is consistently applied. The loan workout policy and practices should be commensurate with each credit union's size and complexity, and must be in line with the credit union's broader risk mitigation strategies. The policy must define eligibility requirements (i.e. under what conditions the credit union will consider a loan workout), including establishing limits on the number of times an individual loan may be modified.[3] The policy must also ensure credit unions make loan workout decisions based on the borrower's renewed willingness and ability to repay the loan. If a credit union engages in restructuring activity on a loan that results in restructuring the loan more often than once a year or twice in five years, examiners will have higher expectations for the documentation of the borrower's renewed willingness and ability to repay the loan. NCUA is concerned about restructuring activity that pushes existing losses into future reporting periods without improving the loan's collectability. One way a credit union can provide convincing evidence that multiple restructurings improve collectability is to perform validation of completed multiple restructurings that substantiate the claim. Examiners will ask for such validation documentation if the credit union engages in multiple restructurings of a loan.

In addition, the policy must establish sound controls to ensure loan workout actions are appropriately structured.[4] The policy must provide that in no event may the credit union authorize additional advances to finance unpaid interest and credit union fees. The credit union may, however, make advances to cover third-party fees, excluding credit union commissions, such as force-placed insurance or property taxes. For loan workouts granted, the credit union must document the determination that the borrower is willing and able to repay the loan.

Management must ensure that comprehensive and effective risk management and internal controls are established and maintained so that loan workouts can be adequately controlled and monitored by the credit union's board of directors and management, to provide for timely recognition of losses,[5] and to permit review by examiners. The credit union's risk management framework must include thresholds based on aggregate volume of loan workout activity that trigger enhanced reporting to the board of directors. This reporting will enable the credit union's board of directors to evaluate the effectiveness of the credit union's loan workout program, any implications to the organization's financial condition, and to make any compensating adjustments to the overall business strategy.

[1] Terms defined in the Glossary will be italicized on their first use in the body of this guidance.

[2] For additional guidance on member business lending extension, deferral, renewal, and rewrite policies, see *Interagency Policy Statement on Prudent Commercial Real Estate Loan Workouts* (October 30, 2009) transmitted by Letter to Credit Unions No. 10–CU–07, and available at *http://www.ncua.gov*.

[3] Broad based credit union programs commonly used as a member benefit and implemented in a safe and sound manner limited to only accounts in good standing, such as Skip-a-Pay programs, are not intended to count toward these limits.

[4] In developing a written policy, the credit union board and management may wish to consider similar parameters as those established in the FFIEC's ''Uniform Retail Credit Classification and Account Management Policy'' (FFIEC Policy). 65 FR 36903 (June 12, 2000). The FFIEC Policy sets forth specific limitations on the number of times a loan can be re-aged (for open-end accounts) or extended, deferred, renewed or rewritten (for closed-end accounts). Additionally, NCUA Letter to Credit Unions (LCU) 09–CU–19, ''Evaluating Residential Real Estate Mortgage Loan Modification Programs,'' outlines policy requirements for real estate modifications. Those requirements remain applicable to real estate loan modifications but could be adapted in part by the credit union in their written loan workout policy for other loans.

[5] Refer to NCUA guidance on charge-offs set forth in LCU 03–CU–01, ''Loan Charge-off Guidance,'' dated January 2003. Examiners will require that a reasonable written charge-off policy is in place and that it is consistently applied. Additionally, credit unions need to adjust historical loss factors when calculating ALLL needs for pooled loans to account for any loans with protracted charge-off timeframes (e.g., 12 months or greater). See discussions on the latter point in the 2006 Interagency ALLL Policy Statement transmitted by Accounting Bulletin 06–1 (December 2006).

This information will also then be available to examiners upon request.

To be effective, management information systems need to track the principal reductions and *charge-off* history of loans in workout programs by type of program. Any decision to re-age, extend, defer, renew, or rewrite a loan, like any other revision to contractual terms, needs to be supported by the credit union's management information systems. Sound management information systems are able to identify and document any loan that is re-aged, extended, deferred, renewed, or rewritten, including the frequency and extent such action has been taken. Documentation normally shows that the credit union's personnel communicated with the borrower, the borrower agreed to pay the loan in full under any new terms, and the borrower has the ability to repay the loan under any new terms.

Regulatory Reporting of Workout Loans Including TDR Past Due Status

The past due status of all loans will be calculated consistent with loan contract terms, including amendments made to loan terms through a formal restructure. Credit unions will report delinquency on the Call Report consistent with this policy.[6]

Loan Nonaccrual Policy

Credit unions must ensure appropriate income recognition by placing loans in nonaccrual status when conditions as specified below exist, reversing or charging-off previously accrued but uncollected interest, complying with the criteria under GAAP for Cash or Cost Recovery basis of income recognition, and following the specifications below regarding restoration of a nonaccrual loan to accrual status.[7] This policy on loan accrual is consistent with longstanding credit union industry practice as implemented by the NCUA over the last several decades. The balance of the policy relates to *member business loan* workouts and is similar to the FFIEC policies adopted by the federal banking agencies[8] as set forth in the FFIEC Call Report for banking institutions and its instructions.[9]

Nonaccrual Status

Credit unions may not accrue interest[10] on any loan upon which principal or interest has been in default for a period of 90 days or more, unless the loan is both ''*well secured*'' and ''in the *process of collection*.''[11] Additionally, loans will be placed in nonaccrual status if maintained on a Cash (or Cost Recovery) basis because of deterioration in the financial condition of the borrower, or for which payment in full of principal or interest is not expected. For purposes of applying the ''well secured'' and ''in process of collection'' test for nonaccrual status listed above, the date on which a loan reaches nonaccrual status is determined by its contractual terms.

While a loan is in nonaccrual status, some or all of the cash interest payments received may be treated as interest income on a cash basis as long as the remaining *recorded investment in the loan* (i.e., after charge-off of identified losses, if any) is deemed to be fully collectable. The reversal of previously accrued, but uncollected, interest applicable to any loan placed in nonaccrual status must be handled in accordance with GAAP.[12] Where assets are collectable over an extended period of time and, because of the terms of the transactions or other conditions, there is no reasonable basis for estimating the degree of collectability—when such circumstances exist, and as long as they exist—consistent with GAAP the Cost Recovery Method of accounting must be used.[13] Use of the Cash or Cost Recovery basis for these loans and the statement on reversing previous accrued interest is the practical implementation of relevant accounting principles.

Restoration to Accrual Status for All Loans except Member Business Loan Workouts

A nonaccrual loan may be restored to accrual status when:

- Its past due status is less than 90 days, GAAP does not require it to be maintained on the Cash or Cost Recovery basis, and the credit union is plausibly assured of repayment of the remaining contractual principal and interest within a reasonable period;
- When it otherwise becomes both *well secured* and *in the process of collection;* or
- The asset is a purchased impaired loan and it meets the criteria under GAAP for accrual of income under the interest method specified therein.

In restoring all loans to accrual status, if any interest payments received while the loan was in nonaccrual status were applied to reduce the recorded investment in the loan the application of these payments to the loan's recorded investment must not be reversed (and interest income must not be credited). Likewise, accrued but uncollected interest reversed or charged-off at the point the loan was placed on nonaccrual status cannot be restored to accrual; it can only be recognized as income if collected in cash or cash equivalents from the member.

Restoration to Accrual Status on Member Business Loan Workouts[14]

A formally restructured member business loan workout need not be maintained in nonaccrual status, provided the restructuring and any charge-off taken on the loan are supported by a current, well documented credit evaluation of the borrower's financial condition and prospects for repayment under the revised terms. Otherwise, the restructured loan must remain in nonaccrual status. The evaluation must include consideration of the borrower's sustained historical repayment performance for a reasonable period prior to the date on which the loan is returned to accrual status. A sustained period of repayment performance would be a minimum of six consecutive payments and would involve timely payments under the restructured loan's terms of principal and interest in cash or cash equivalents. In returning the member business workout loan to accrual status, sustained historical repayment performance for a reasonable time prior to the restructuring may be taken into account. Such a restructuring must improve the collectability of the loan in accordance with a reasonable repayment schedule and does not relieve the credit union from the responsibility to promptly charge off all identified losses.

[6] Subsequent Call Reports and accompanying instructions will reflect this policy, including focusing data collection on loans meeting the definition of TDR under GAAP. In reporting TDRs on regulatory reports, the data collections will include all TDRs that meet the GAAP criteria for TDR reporting, without the application of materiality threshold exclusions based on scoping or reporting policy elections of credit union preparers or their auditors. Credit unions should also refer to the recently revised standard from the FASB, Accounting Standards Update No. 2011–02 (April 2011) to the FASB Accounting Standards Codification entitled, Receivables (Topic 310), ''A Creditor's Determination of Whether a Restructuring is a Troubled Debt Restructuring.'' This clarified the definition of a TDR, which has the practical effect in the current economic environment to broaden loan workouts that constitute a TDR. This standard is effective for annual periods ending on or after December 15, 2012.

[7] Placing a loan in nonaccrual status does not change the loan agreement or the obligations between the borrower and the credit union. Only the parties can effect a restructuring of the original loan terms or otherwise settle the debt.

[8] The federal banking agencies are the Board of Governors of the Federal Reserve System, the Federal Deposit Insurance Corporation, and the Office of the Comptroller of the Currency.

[9] FFIEC Report of Condition and Income Forms and User Guides, Updated September 2011, *http://www.fdic.gov.*

[10] Nonaccrual of interest also includes the amortization of deferred net loan fees or costs, or the accretion of discount. Nonaccrual of interest on loans past due 90 days or more is a longstanding agency policy and credit union practice.

[11] A purchased credit impaired loan asset need not be placed in nonaccrual status as long as the criteria for accrual of income under the interest method in GAAP is met. Also, the accrual of interest on workout loans is covered in a separate section of this IRPS later in the policy statement.

[12] Acceptable accounting treatment includes a reversal of all previously accrued, but uncollected, interest applicable to loans placed in a nonaccrual status against appropriate income and balance sheet accounts. For example, one acceptable method of accounting for such uncollected interest on a loan placed in nonaccrual status is: (1) To reverse all of the unpaid interest by crediting the ''accrued interest receivable'' account on the balance sheet, (2) to reverse the uncollected interest that has been accrued during the calendar year-to-date by debiting the appropriate ''interest and fee income on loans'' account on the income statement, and (3) to reverse any uncollected interest that had been accrued during previous calendar years by debiting the ''allowance for loan and lease losses'' account on the balance sheet. The use of this method presumes that credit union management's additions to the allowance through charges to the ''provision for loan and lease losses'' on the income statement have been based on an evaluation of the collectability of the loan and lease portfolios and the ''accrued interest receivable'' account.

[13] When a purchased impaired loan or debt security that is accounted for in accordance with ASC Subtopic 310–30, ''Receivables-Loans and Debt Securities Acquired with Deteriorated Credit Quality,'' has been placed on nonaccrual status, the cost recovery method should be used, when appropriate.

[14] This policy is derived from the ''Interagency Policy Statement on Prudent Commercial Real Estate Loan Workouts'' NCUA and the other financial regulators issued on October 30, 2009.

The graph below provides an example of a schedule of repayment performance to demonstrate a determination of six consecutive payments. If the original loan terms required a monthly payment of $1,500, and the credit union lowered the borrower's payment to $1,000 through formal member business loan restructure, then based on the first row of the graph, the ''*sustained historical repayment performance for a reasonable time prior to the restructuring''* would encompass five of the pre-workout consecutive payments that were at least $1,000 (Months 1 through 5); so, in total, the six consecutive repayment burden would be met by the first month post workout (Month 6). In the second row, only one of the pre-workout payments would count toward the six consecutive repayment requirement (Month 5), because it is the first month in which the borrower made a payment of at least $1,000, after failing to pay at least that amount. The loan, therefore, would remain on nonaccrual for at least five post-workout consecutive payments (Months 6 through 10) provided the borrower continues to make payments consistent with the restructured terms.

Pre-workout					Post-workout				
Month 1	Month 2	Month 3	Month 4	Month 5	Month 6	Month 7	Month 8	Month 9	Month 10
$1,500	$1,200	$1,200	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000
1,500	1,200	900	875	1,000	1,000	1,000	1,000	1,000	1,000

After a formal restructure of a member business loan, if the restructured loan has been returned to accrual status, the loan otherwise remains subject to the nonaccrual standards of this policy. If any interest payments received while the member business loan was in nonaccrual status were applied to reduce the recorded investment in the loan the application of these payments to the loan's recorded investment must not be reversed (and interest income must not be credited). Likewise, accrued but uncollected interest reversed or charged-off at the point the member business workout loan was placed on nonaccrual status cannot be restored to accrual; it can only be recognized as income if collected in cash or cash equivalents from the member.

The following tables summarize nonaccrual and restoration to accrual requirements previously discussed:

TABLE 1—NONACCRUAL CRITERIA

Action	Condition identified	Additional consideration
Nonaccrual on All Loans	90 days or more past due unless loan is both well secured and in the process of collection; or If the loan must be maintained on the Cash or Cost Recovery basis because there is a deterioration in the financial condition of the borrower, or for which payment in full of principal or interest is not expected.	See Glossary descriptors for ''well secured'' and ''in the process of collection.'' Consult GAAP for Cash or Cost Recovery basis income recognition guidance. See also Glossary Descriptors.
Nonaccrual on Member Business Loan Workouts.	Continue on nonaccrual at workout point and until restore to accrual criteria are met.	See Table 2—Restore to Accrual.

TABLE 2—RESTORE TO ACCRUAL

Action	Condition identified	Additional consideration
Restore to Accrual on All Loans except Member Business Loan Workouts.	When the loan is past due less than 90 days, GAAP does not require it to be maintained on the Cash or Cost Recovery basis, and the credit union is plausibly assured of repayment of the remaining contractual principal and interest within a reasonable period. When it otherwise becomes both ''well secured'' and ''in the process of collection''; or The asset is a purchased impaired loan and it meets the criteria under GAAP for accrual of income under the interest method.	See Glossary descriptors for ''well secured'' and ''in the process of collection.'' Interest payments received while the loan was in nonaccrual status and applied to reduce the recorded investment in the loan must not be reversed and income credited. Likewise, accrued but uncollected interest reversed or charged-off at the point the loan was placed on nonaccrual status cannot be restored to accrual.
Restore to Accrual on Member Business Loan Workouts.	Formal restructure with a current, well documented credit evaluation of the borrower's financial condition and prospects for repayment under the revised terms.	The evaluation must include consideration of the borrower's sustained historical repayment performance for a minimum of six timely consecutive payments comprised of principal and interest. In returning the loan to accrual status, sustained historical repayment performance for a reasonable time prior to the restructuring may be taken into account. Interest payments received while the member business loan was in nonaccrual status and applied to reduce the recorded investment in the loan must not be reversed and income credited. Likewise, accrued but uncollected interest reversed or charged-off at the point the member business loan was placed on nonaccrual status cannot be restored to accrual.

Glossary [15]

''*Cash Basis''* method of income recognition is set forth in GAAP and means while a loan is in nonaccrual status, some or all of the cash interest payments received may be treated as interest income on a cash basis as long as the remaining recorded investment in the loan (i.e., after charge-off of identified losses, if any) is deemed to be fully collectible.[16]

''*Charge-off*'' means a direct reduction (credit) to the carrying amount of a loan carried at amortized cost resulting from uncollectability with a corresponding reduction (debit) of the ALLL. Recoveries of loans previously charged off should be recorded when received.

''*Cost Recovery*'' method of income recognition means equal amounts of revenue and expense are recognized as collections are made until all costs have been recovered, postponing any recognition of profit until that time.[17]

''*Generally accepted accounting principles (GAAP)*'' means official pronouncements of the FASB as memorialized in the FASB Accounting Standards Codification® as the source of authoritative principles and standards recognized to be applied in the preparation of financial statements by federally-insured credit unions in the United States with assets of $10 million or more.

''*In the process of collection*'' means collection of the loan is proceeding in due course either: (1) Through legal action, including judgment enforcement procedures, or (2) in appropriate circumstances, through collection efforts not involving legal action which are reasonably expected to result in repayment of the debt or in its restoration to a current status in the near future, i.e., generally within the next 90 days.

''Member Business Loan'' is defined consistent with Section 723.1 of NCUA's Member Business Loan Rule, 12 CFR 723.1.

''New Loan'' means the terms of the revised loan are at least as favorable to the credit union (i.e., terms are market-based, and profit driven) as the terms for comparable loans to other customers with similar collection risks who are not refinancing or restructuring a loan with the credit union, and the revisions to the original debt are more than minor.

''Past Due'' means a loan is determined to be delinquent in relation to its contractual repayment terms including formal restructures, and must consider the time value of money. Credit unions may use the following method to recognize partial payments on ''consumer credit,'' i.e., credit extended to individuals for household, family, and other personal expenditures, including credit cards, and loans to individuals secured by their personal residence, including home equity and home improvement loans. A payment equivalent to 90 percent or more of the contractual payment may be considered a full payment in computing past due status.

''Recorded Investment in a Loan'' means the loan balance adjusted for any unamortized premium or discount and unamortized loan fees or costs, less any amount previously charged off, plus recorded accrued interest.

''Troubled Debt Restructuring'' is as defined in GAAP and means a restructuring in which a credit union, for economic or legal reasons related to a member borrower's financial difficulties, grants a concession to the borrower that it would not otherwise consider.[18] The restructuring of a loan may include, but is not necessarily limited to: (1) The transfer from the borrower to the credit union of real estate, receivables from third parties, other assets, or an equity interest in the borrower in full or partial satisfaction of the loan, (2) a modification of the loan terms, such as a reduction of the stated interest rate, principal, or accrued interest or an extension of the maturity date at a stated interest rate lower than the current market rate for new debt with similar risk, or (3) a combination of the above. A loan extended or renewed at a stated interest rate equal to the current market interest rate for new debt with similar risk is not to be reported as a restructured troubled loan.

''Well secured'' means the loan is collateralized by: (1) A perfected security interest in, or pledges of, real or personal property, including securities with an estimable value, less cost to sell, sufficient to recover the recorded investment in the loan, as well as a reasonable return on that amount, or (2) by the guarantee of a financially responsible party.

''Workout Loan'' means a loan to a borrower in financial difficulty that has been formally restructured so as to be reasonably assured of repayment (of principal and interest) and of performance according to its restructured terms. A workout loan typically involves a *re-aging, extension, deferral, renewal, or rewrite* of a loan.[19] For purposes of this policy statement, workouts do not include loans made to market rates and terms such as refinances, borrower retention actions, or new loans.[20]

[15] Terms defined in the Glossary will be italicized on their first use in the body of this guidance.

[16] Acceptable accounting practices include: (1) Allocating contractual interest payments among interest income, reduction of the recorded investment in the asset, and recovery of prior charge-offs. If this method is used, the amount of income that is recognized would be equal to that which would have been accrued on the loan's remaining recorded investment at the contractual rate; and, (2) accounting for the contractual interest in its entirety either as income, reduction of the recorded investment in the asset, or recovery of prior charge-offs, depending on the condition of the asset, consistent with its accounting policies for other financial reporting purposes.

[17] FASB Accounting Standards Codification (ASC) 605–10–25–4, ''Revenue Recognition, Cost Recovery.''

[18] FASB ASC 310–40, ''Troubled Debt Restructuring by Creditors.''

[19] *''Re-Age''* means returning a past due account to current status without collecting the total amount of principal, interest, and fees that are contractually due.

''Extension'' means extending monthly payments on a closed-end loan and rolling back the maturity by the number of months extended. The account is shown current upon granting the extension. If extension fees are assessed, they should be collected at the time of the extension and not added to the balance of the loan.

''Deferral'' means deferring a contractually due payment on a closed-end loan without affecting the other terms, including maturity, of the loan. The account is shown current upon granting the deferral.

''Renewal'' means underwriting a matured, closed-end loan generally at its outstanding principal amount and on similar terms.

''Rewrite'' means significantly changing the terms of an existing loan, including payment amounts, interest rates, amortization schedules, or its final maturity.

[20] There may be instances where a workout loan is not a TDR even though the borrower is experiencing financial hardship. For example, a workout loan would not be a TDR if the fair value of cash or other assets accepted by a credit union from a borrower in full satisfaction of its receivable is at least equal to the credit union's recorded investment in the loan, e.g., due to charge-offs.

[FR Doc. 2012–13214 Filed 5–30–12; 8:45 am]

BILLING CODE 7535–01–P

NATIONAL CREDIT UNION ADMINISTRATION

12 CFR Chapter VII

Guidelines for the Supervisory Review Committee

AGENCY: National Credit Union Administration (NCUA).

ACTION: Direct final Interpretive Ruling and Policy Statement (IRPS) 12–1, with request for comments.

SUMMARY: This direct final policy statement amends IRPS 11–1, which addresses appeals to NCUA's Supervisory Review Committee. NCUA adopts IRPS 12–1 to remove Regulatory Flexibility designation determinations from the list of material supervisory determinations credit unions may appeal to the Committee because NCUA is eliminating the RegFlex program contemporaneously with the issuance of this IRPS.

DATES: This IRPS is effective August 29, 2012 unless NCUA withdraws the IRPS by July 30, 2012. Comments must be received by July 2, 2012.

ADDRESSES: You may submit comments by any of the following methods (Please send comments by one method only):

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

• *NCUA Web Site: http:// www.ncua.gov/Legal/Regs/Pages/ PropRegs.aspx* Follow the instructions for submitting comments.

• *Email:* Address to *regcomments@ncua.gov.* Include ''[Your name] Comments on IRPS 12–1'' in the email subject line.

• *Fax:* (703) 518–6319. Use the subject line described above for email.

• *Mail:* Address to Mary Rupp, Secretary of the Board, National Credit Union Administration, 1775 Duke Street, Alexandria, Virginia 22314–3428.

• *Hand Delivery/Courier:* Same as mail address.

Public Inspection: You can view all public comments on NCUA's Web site at *http://www.ncua.gov/Legal/Regs/Pages/PropRegs.aspx* as submitted, except for those we cannot post for technical reasons. NCUA will not edit or remove any identifying or contact information from the public comments submitted. You may inspect paper copies of comments in NCUA's law library at 1775 Duke Street, Alexandria, Virginia 22314, by appointment weekdays between 9 a.m. and 3 p.m. To make an appointment, call (703) 518–6546 or send an email to *OGCMail@ncua.gov.*

FOR FURTHER INFORMATION CONTACT: Chrisanthy Loizos, Staff Attorney, Office of General Counsel, at the above address or telephone (703) 518–6540.

SUPPLEMENTARY INFORMATION:

I. Background

In 1995, the NCUA Board (Board) adopted guidelines that established an independent appellate process to review material supervisory determinations, entitled ''Supervisory Review Committee'' (IRPS 95–1). Public Law 103–325, § 309(a), 108 Stat. 2160 (1994); 60 FR 14795 (Mar. 20, 1995). Through IRPS 95–1, NCUA established a Supervisory Review Committee (Committee) consisting of three senior staff members to hear appeals of material supervisory determinations. IRPS 95–1 defined material supervisory determinations to include determinations on composite CAMEL ratings of 3, 4 and 5, all component ratings of those composite ratings, significant loan classifications and adequacy of loan loss reserves. In 2002, the Board amended IRPS 95–1 by issuing IRPS 02–1, which added Regulatory Flexibility (RegFlex) designation determinations to the list of material supervisory determinations credit unions may appeal to the Committee. 78 FR 19778 (Apr. 23, 2002). In order to centralize all applicable guidance on the Committee and ensure ease of understanding by credit unions, the Board combined IRPS 95–1 and 02–1 into IRPS 11–1. 83 FR 23871 (Apr. 29, 2011).

In December 2011, the Board issued a Notice of Proposed Rulemaking (NPRM) to eliminate its RegFlex program and remove corresponding part 742 of NCUA's regulations. 76 FR 81421 (Dec. 28, 2011). In the NPRM, the Board notified the public that, upon issuance of a final RegFlex rule, it would amend IRPS 11–1 to remove the RegFlex appeals process. 76 FR at 81422. Contemporaneous with this adoption of IRPS 12–1, the Board is adopting the NPRM as a final rule in a separate rulemaking. The final rule provides regulatory relief by expanding RegFlex authorities to all federal credit unions, rather than only those that qualified for a RegFlex designation. The final rule also removes or amends related rules to ease compliance burden while retaining certain safety and soundness standards.

II. IRPS 12–1

IRPS 12–1 amends IRPS 11–1 by removing all references to the RegFlex program. The amendments remove RegFlex designations as the fourth type of material supervisory determination a federal credit union could appeal in subpart A's third paragraph. It also removes subpart A's seventh paragraph, which set the time frame for filing RegFlex appeals. Finally, it removes the second sentence in the last paragraph in subpart A, which permitted further appeals to the Board.

III. Issuance as Direct Final

The Board is issuing this IRPS as a direct final IRPS under the Administrative Procedure Act (APA), 5 U.S.C. 553(b)(3)(A) and § 553(b)(3)(B), because these provisions allow an agency to issue rules without notice and comment in the case of interpretative rules and when it finds for good cause that these procedures are unnecessary. IRPS 11–1, as amended by IRPS 12–1, is an interpretation of agency procedure. Notice and public procedures are unnecessary because the Board finds that IRPS 12–1 is noncontroversial and believes it will not elicit significant adverse comments. The Board's rulemaking action to remove part 742 renders the RegFlex appeals process in IRPS 11–1 moot. IRPS 12–1, therefore, is merely a housekeeping measure to remove references to a nonexistent program. The Board finds these reasons are good cause to dispense with the APA's notice and comment period and the procedures in NCUA's IRPS 87–2. 5 U.S.C. 553(b)(3)(B); 52 FR 35213 (Sept. 18, 1987), as amended by IRPS 03–2, 68 FR 31949 (May 29, 2003).

Although the IRPS is being issued as a direct final IRPS, interested parties have a 30-day comment period. If NCUA receives a significant adverse comment that explains why the IRPS is inappropriate, challenges its underlying premise, or states why it would be ineffective or unacceptable without a change, the agency will withdraw the IRPS by July 30, 2012. Unless NCUA publishes a **Federal Register** notice withdrawing the IRPS by this date, the IRPS will become effective on August 29, 2012.

IV. Regulatory Procedures

Regulatory Flexibility Act

The Regulatory Flexibility Act requires NCUA to prepare an analysis to describe any significant economic impact a rule may have on a substantial number of small entities (primarily those under ten million dollars in assets). This final IRPS removes the appeal of RegFlex designations from the Committee's purview because the RegFlex program no longer exists. NCUA has determined and certifies that this IRPS will not have a significant economic impact on a substantial number of small credit unions.

Paperwork Reduction Act

The Paperwork Reduction Act of 1995 (PRA) applies to rulemakings in which an agency by rule creates a new paperwork burden on regulated entities or modifies an existing burden. 44 U.S.C. 3507(d); 5 CFR part 1320. For purposes of the PRA, a paperwork burden may take the form of either a reporting or a recordkeeping requirement, both referred to as information collections. NCUA has determined that this final IRPS does not increase paperwork requirements under the PRA and regulations of the Office of Management and Budget.

Executive Order 13132

Executive Order 13132 encourages independent regulatory agencies to consider the impact of their actions on state and local interests. NCUA, an independent regulatory agency as defined in 44 U.S.C. 3502(5), voluntarily complies with the executive order to adhere to fundamental federalism principles. This final IRPS applies to credit unions that appeal NCUA's material supervisory determinations before the Committee. It does 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. NCUA has determined that this final IRPS does not constitute a policy that has federalism implications for purposes of the executive order.

Assessment of Federal Regulations and Policies on Families

NCUA has determined that this final IRPS will not affect family well-being within the meaning of Section 654 of the Treasury and General Government Appropriations Act, 1999, Public Law 105–277, 112 Stat. 2681 (1998).

Small Business Regulatory Enforcement Fairness Act

The Small Business Regulatory Enforcement Fairness Act of 1996 (Pub. L. 104–121) provides generally for congressional review of agency rules. A reporting requirement is triggered in instances where NCUA issues a final rule as defined by Section 551 of the APA. 5 U.S.C. 551. The Office of Management and Budget has determined that this rule is not a major rule for purposes of the Small Business Regulatory Enforcement Fairness Act of 1996.

Dated: By the National Credit Union Administration Board on May 24, 2012.

Mary F. Rupp,

Secretary of the Board.

Accordingly, for the reasons set forth in the preamble, IRPS 12–1 amends IRPS 11–1 as follows:

Note: The following ruling will not appear in the Code of Federal Regulations.

■ 1. Authority: Section 309 of the Riegle Community Development and Regulatory Improvement Act of 1994, Pub. L. 103–325.

■ 2. Amend the third paragraph in subpart A to read as follows:

Material supervisory determinations are limited to: (1) Composite CAMEL ratings of 3, 4, and 5 and all component ratings of those composite ratings; (2) adequacy of loan loss reserve provisions; and (3) loan classifications on loans that are significant as determined by the appealing credit union. Subject to the requirements discussed below, credit unions may also appeal to the Committee a decision of the Director of the Office of Small Credit Union Initiatives (OSCUI) to deny Technical Assistance Grant (TAG) reimbursements.

■ 3. Remove the 7th paragraph in subpart A.

■ 4. Revise the last paragraph in subpart A to read as follows:

Committee decisions on the denial of a TAG reimbursement are the final decisions of NCUA and are not appealable to the NCUA Board. All other appealable decisions must be appealed to the NCUA Board within 30 days of the appellant's receipt by the party of the Committee's decision.

[FR Doc. 2012–13210 Filed 5–30–12; 8:45 am]

BILLING CODE 7535–01–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 25

[Docket No. NM438 Special Conditions No. 25–423–SC]

Special Conditions: Gulfstream Model GVI Airplane; High Incidence Protection

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final special conditions; correction.

SUMMARY: This document corrects an error that appeared in Docket No. NM438, Special Conditions No. 25–423–SC, which were published in the **Federal Register** on March 28, 2011. The error resulted in the omission of two paragraphs of text in The Special Conditions section.

DATES: Effective May 31, 2012.

FOR FURTHER INFORMATION CONTACT: Joe Jacobsen, FAA, Airplane and Flight Crew Interface Branch, ANM–111, Transport Standards Staff, Transport Airplane Directorate, Aircraft Certification Service, 1601 Lind Avenue SW., Renton, Washington 98057–3356; telephone (425) 227–2011; facsimile (425) 227–1320.

SUPPLEMENTARY INFORMATION: The document designated as ''Docket No. NM438, Special Conditions No. 25–423–SC'' was published in the **Federal Register** on March 28, 2011 (76 FR 17022). The document issued special conditions pertaining to a high incidence protection system that replaces the stall warning system during normal operating conditions, prohibits the airplane from stalling, limits the angle of attack at which the airplane can be flown during normal low speed operations, and cannot be overridden by the flight crew. These special conditions were, and continue to be applicable to, Gulfstream Model GVI airplanes.

As published, the document contained an error because paragraphs 3(e)(6) and 3(e)(7) were omitted. Due to its complexity the entire text of paragraph 3(e) is included below, including paragraphs 3(e)(6) and 3(e)(7).

3. *Minimum Steady Flight Speed and Reference Stall Speed*—In lieu of the requirements of § 25.103, the following special condition is issued:

(e) V_{SR} must be determined with the following conditions:

(1) Engines idling, or, if that resultant thrust causes an appreciable decrease in stall speed, not more than zero thrust at the stall speed.

(2) The airplane in other respects (such as flaps and landing gear) in the condition existing in the test or performance standard in which V_{SR} is being used.

(3) The weight used when V_{SR} is being used as a factor to determine compliance with a required performance standard.

(4) The center of gravity position that results in the highest value of reference stall speed.

(5) The airplane trimmed for straight flight at a speed selected by the applicant, but not less than 1.13 V_{SR} and not greater than 1.3 V_{SR}.

(6) The high incidence protection function disabled, or adjusted to a high enough incidence to allow full development of the maneuver to the angle of attack corresponding to V_{SR}.

(7) From the stabilized trim condition, apply the longitudinal control to decelerate the airplane so that the speed reduction does not exceed one knot per second.

Since no other part of the regulatory information has been changed, the special conditions are not being republished.

Correction

In Final special conditions document [FR Doc. 2011–7144 Filed 3–25–11; 8:45 a.m.] published on March 28, 2011 (76 FR 17022), make the following correction:

On page 17024, in the first column, which begins with (e), include the following paragraphs after (5) and before (f):

(6) The high incidence protection function disabled, or adjusted to a high enough incidence to allow full development of the maneuver to the angle of attack corresponding to V_{SR}.

(7) From the stabilized trim condition, apply the longitudinal control to decelerate the airplane so that the speed reduction does not exceed one knot per second.

Issued in Renton, Washington, on May 18, 2012.

Michael J. Kaszycki,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 2012–13213 Filed 5–30–12; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2012–0418; Directorate Identifier 2012–NE–12–AD; Amendment 39–17064; AD 2012–11–01]

RIN 2120–AA64

Airworthiness Directives; Rolls-Royce plc Turbofan Engines

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule; request for comments.

SUMMARY: We are adopting a new airworthiness directive (AD) for all Rolls-Royce plc (RR) RB211–Trent 800 series turbofan engines. This AD requires removal from service of certain critical engine parts based on reduced life limits. This AD was prompted by RR adding a new flight profile and an associated set of life limits. We are issuing this AD to prevent the failure of critical rotating parts, which could result in uncontained failure of the engine and damage to the airplane.

DATES: This AD becomes effective June 15, 2012.

We must receive comments on this AD by July 16, 2012.

ADDRESSES: You may send comments by any of the following methods:

• *Federal eRulemaking Portal:* Go to *http://www.regulations.gov* and follow the instructions for sending your comments electronically.

• *Mail:* U.S. Department of Transportation, 1200 New Jersey Avenue SE., West Building Ground Floor, Room W12–140, Washington, DC 20590–0001.

• *Hand Delivery:* Deliver to Mail address above between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

• *Fax:* 202–493–2251.

For service information identified in this AD, contact Rolls-Royce plc, Corporate Communications, P.O. Box 31, Derby, England DE248BJ; phone: 011–44–1332–242424; fax: 011–44–1332–245418 or email from *http://www.rolls-royce.com/contact/civil_team.jsp,* or download the publication from *https://www.aeromanager.com.* You may review copies of the referenced service information at the FAA, Engine & Propeller Directorate, 12 New England Executive Park, Burlington, MA. For information on the availability of this material at the FAA, call 781–238–7125.

Examining the AD Docket

You may examine the AD docket on the Internet at *http://www.regulations.gov;* or in person at the Docket Operations office between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The AD docket contains this AD, the regulatory evaluation, any comments received, and other information. The street address for the Docket Operations office (phone: 800–647–5527) is the same as the Mail address provided in the **ADDRESSES** section. Comments will be available in the AD docket shortly after receipt.

FOR FURTHER INFORMATION CONTACT: Alan Strom, Aerospace Engineer, Engine Certification Office, FAA, Engine & Propeller Directorate, 12 New England Executive Park, Burlington, MA 01803; phone: 781–238–7143; fax: 781–238–7199; email: *alan.strom@faa.gov.*

SUPPLEMENTARY INFORMATION:

Discussion

The European Aviation Safety Agency (EASA), which is the Technical Agent for the Member States of the European Community, has issued EASA AD 2012–0051, dated March 26, 2012 (referred to after this as ''the MCAI''), to correct an unsafe condition for the specified products. The MCAI states:

> Flight Profiles (FP) define the limits of engine operation within which the engine will qualify for use of an associated set of Critical Parts life limits. The Rolls-Royce RB211–Trent 800 engine previously had seven such FPs and associated sets of life limits published in the RR Time Limits Manual.
>
> However, the results of a recent review of operational flight data determined that the existing FPs do not encompass the full range of Trent 800 operations. To account for the consequent increased rate of fatigue life usage on the life limited Critical Parts, a new FP and associated set of reduced life limits for Critical Parts has been developed, defined as FP ''MAX'', that defines a new level of operation which is outside the ''HEAVY'' FP, previously the most arduous.

We are issuing this AD to prevent the failure of critical rotating parts, which could result in uncontained failure of the engine and damage to the airplane. You may obtain further information by examining the MCAI in the AD docket.

FAA's Determination and Requirements of This AD

This product has been approved by the United Kingdom and is approved for operation in the United States. Pursuant to our bilateral agreement with the European Community, EASA has notified us of the unsafe condition described in the MCAI and service information referenced above. We are issuing this AD because we evaluated all information provided by EASA and determined the unsafe condition exists and is likely to exist or develop on other products of the same type design.

FAA's Determination of the Effective Date

An unsafe condition exists that requires the immediate adoption of this AD. The FAA has found that the risk to the flying public justifies waiving notice and comment prior to adoption of this rule because some parts may require immediate removal upon recalculation of the part lives in accordance with the AD. Therefore, we determined that notice and opportunity for public comment before issuing this AD are impracticable and that good cause exists for making this amendment effective in fewer than 30 days.

Comments Invited

This AD is a final rule that involves requirements affecting flight safety, and we did not precede it by notice and opportunity for public comment. We invite you to send any written relevant data, views, or arguments about this AD. Send your comments to an address listed under the **ADDRESSES** section. Include ''Docket No. FAA–2012–0418; Directorate Identifier 2012–NE–12–AD'' at the beginning of your comments. We specifically invite comments on the overall regulatory, economic, environmental, and energy aspects of this AD. We will consider all comments received by the closing date and may amend this AD because of those comments.

We will post all comments we receive, without change, to *http://www.regulations.gov,* including any personal information you provide. We will also post a report summarizing each substantive verbal contact with FAA personnel concerning this AD. Using the search function of the Web site, anyone can find and read the comments in any of our dockets, including, if provided, 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).

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 determined that this AD will not have federalism implications under Executive Order 13132. This AD will not have a substantial direct effect on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.

For the reasons discussed above, I certify this AD:

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.
4. We prepared a regulatory evaluation of the estimated costs to comply with this AD and placed it in the AD docket.

List of Subjects in 14 CFR Part 39

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

Adoption of the Amendment

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

PART 39—AIRWORTHINESS DIRECTIVES

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

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

§ 39.13 [Amended]

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

2012–11–01 Rolls-Royce plc: Amendment 39–17064; Docket No. FAA–2012–0418; Directorate Identifier 2012–NE–12–AD.

(a) Effective Date

This airworthiness directive (AD) becomes effective June 15, 2012.

(b) Affected ADs

None.

(c) Applicability

This AD applies to Rolls-Royce plc (RR) RB211–Trent 875–17, 877–17, 884–17, 884B–17, 892–17, 892B–17, and 895–17 turbofan engines.

(d) Reason

This AD was prompted by RR adding a new flight profile and an associated set of life limits. We are issuing this AD to prevent the failure of critical rotating parts, which could result in uncontained failure of the engine and damage to the airplane.

(e) Actions and Compliance

Compliance is required within 30 days after the effective date of this AD, unless already done.

(f) After the effective date of this AD, remove from service the parts listed by part number (P/N) in Table 1 of this AD before exceeding the new life limit indicated.

TABLE 1—REDUCED PART LIVES—LIFE IN CYCLES USING THE MAX PROFILE

Part nomenclature	P/N	New life limit in MAX profile cycles
(1) Low-pressure (LP) Compressor Rotor Disc	FK14399, FK30901	10,080.
(2) LP Compressor Rotor Shaft	FK20840	7,950.
(3) Intermediate-pressure (IP) Compressor Rotor Shaft	FK24100, FK24496	8,140.
(4) IP Rear Shaft	FK23564, FW18545	15,000.
(5) High-pressure (HP) Compressor Stage 1 to 4 Rotor Discs Shaft	FK24009	MAX profile cycles prohibited.
(6) HP Compressor Stage 1 to 4 Rotor Discs Shaft	FK26167, FK32580, FW88724.	4,500.
(7) HP Compressor Stage 1 to 4 Rotor Discs Shaft	FW11590, FW61622, FW88723, FW88725.	6,000.
(8) HP Compressor Stage 5 and 6 Discs and Cone	FK25230, FK27899	4,500.
(9) HP Compressor Stage 5 and 6 Discs and Cone	FW24633	5,800.
(10) HP Compressor Stage 5 and 6 Discs and Cone	FW24634	5,060.
(11) HP Turbine Rotor Disc	FK24651, FK24790	4,500.
(12) HP Turbine Rotor Disc	FK26893	5,540.
(13) IP Turbine Rotor Disc	FK21117, FK33049	8,400.
(14) IP Turbine Rotor Disc	FK33083	MAX profile cycles prohibited.
(15) IP Turbine Rotor Shaft	FK23295, FK25180, FW18550, FW19626.	10,380.
(16) LP Turbine Stage 1 Rotor Disc	FK24971	15,000.
(17) LP Turbine Stage 2 Rotor Disc	FK23208, FK26625	15,000.
(18) LP Turbine Stage 3 Rotor Disc	FK24199, FK26626	15,000.
(19) LP Turbine Stage 4 Rotor Disc	FK23210	15,000.
(20) LP Turbine Stage 5 Rotor Disc	FK24200	15,000.
(21) LP Turbine Rotor Shaft	FK20817	7,360.

(g) Installation Prohibition

After the effective date of this AD, do not install any IP turbine rotor discs, P/N FK33083, into any engine.

(h) Alternative Methods of Compliance (AMOCs)

The Manager, Engine Certification Office, FAA, may approve AMOCs to this AD. Use the procedures found in 14 CFR 39.19 to make your request.

(i) Related Information

(1) You may find additional information on calculating MAX Profile Cycles, in RB211 Trent 800 Propulsion Systems Alert Service Bulletin (ASB) No. RB.211–72–AG801 and RR Time Limits Manual 05–00–01–800–801, Recording and Control of the Lives of Parts.

(2) For more information about this AD, contact Alan Strom, Aerospace Engineer, Engine Certification Office, FAA, Engine & Propeller Directorate, 12 New England Executive Park, Burlington, MA 01803; phone: 781–238–7143; fax: 781–238–7199; email: *alan.strom@faa.gov.*

(3) Refer to European Aviation Safety Agency Airworthiness Directive 2012–0051, dated March 26, 2012, and RB211 Trent 800 Propulsion Systems ASB No. RB.211–72–AG801, dated December 8, 2011, for related information.

(4) For service information identified in this AD, contact Rolls-Royce plc, Corporate Communications, P.O. Box 31, Derby, England DE248BJ; phone: 011–44–1332–242424; fax: 011–44–1332–245418 or email from *http://www.rolls-royce.com/contact/civil_team.jsp.*

(i) Material Incorporated by Reference

None.

Issued in Burlington, Massachusetts, on May 16, 2012.

Peter A. White,

Manager, Engine & Propeller Directorate, Aircraft Certification Service.

[FR Doc. 2012–13081 Filed 5–30–12; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2012–0195; Directorate Identifier 2012–NE–08–AD; Amendment 39–17070; AD 2012–11–07]

RIN 2120–AA64

Airworthiness Directives; Honeywell International, Inc. Turbofan Engines

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: We are adopting a new airworthiness directive (AD) for all Honeywell International, Inc. ALF502L–2C; ALF502R–3; ALF502R–3A; ALF502R–5; LF507–1F; and LF507–1H turbofan engines. This AD was prompted by two reports of engines experiencing uncontained release of low-pressure (LP) turbine blades. This AD requires operational checks of the engine overspeed trip system. We are issuing this AD to prevent LP turbine overspeed leading to uncontained release of the LP turbine blades and damage to the airplane.

DATES: This AD is effective July 5, 2012.

Examining the AD Docket

You may examine the AD docket on the Internet at *http://www.regulations.gov;* or in person at the Docket Management Facility between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The AD docket contains this AD, the regulatory evaluation, any comments received, and other information. The address for the Docket Office (phone: 800–647–5527) is Document Management Facility, U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE., Washington, DC 20590.

FOR FURTHER INFORMATION CONTACT: Robert Baitoo, Aerospace Engineer, Los Angeles Aircraft Certification Office, FAA, 3960 Paramount Blvd., Lakewood, CA 90712; phone: 562–627–5245; fax: 562–627–5210; email: *robert.baitoo@faa.gov.*

SUPPLEMENTARY INFORMATION:

Discussion

We issued a notice of proposed rulemaking (NPRM) to amend 14 CFR part 39 to include an AD that would apply to the specified products. That NPRM published in the **Federal Register** on March 9, 2012 (77 FR 14312). That NPRM proposed to require operational checks of the engine overspeed trip system.

Comments

We gave the public the opportunity to participate in developing this AD. We have considered the one comment received. The National Transportation Safety Board supports the NPRM.

Conclusion

We reviewed the relevant data, considered the comment received, and determined that air safety and the public interest require adopting the AD as proposed, except that we determined to not incorporate by reference the engine manuals for the procedures for operational checks of the engine overspeed trip system. Instead, we have included those procedures in the AD. We have determined that these minor changes:

- Are consistent with the intent that was proposed in the NPRM (77 FR 14312, March 9, 2012) for correcting the unsafe condition; and
- Do not add any additional burden upon the public than was already proposed in the NPRM (77 FR 14312, March 9, 2012).

Costs of Compliance

We estimate that this AD will affect 188 Honeywell International, Inc. ALF502L–2C; ALF502R–3; ALF502R–3A; ALF502R–5; LF507–1F; and LF507–1H turbofan engines, installed on airplanes of U.S. registry. We also estimate that it will take about one work-hour to perform an operational check of the overspeed trip system on each engine. The average labor rate is $85 per work-hour. Based on these figures, we estimate the total cost of this AD for one operational check of the overspeed trip system to U.S. operators, to be $15,980.

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

This AD will not have federalism implications under Executive Order 13132. This AD will not have a substantial direct effect on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.

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

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

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

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

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

List of Subjects in 14 CFR Part 39

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

Adoption of the Amendment

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

PART 39—AIRWORTHINESS DIRECTIVES

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

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

§ 39.13 [Amended]

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

2012–11–07 Honeywell International, Inc.: Amendment 39–17070; Docket No. FAA–2012–0195; Directorate Identifier 2012–NE–08–AD.

(a) Effective Date

This AD is effective July 5, 2012.

(b) Affected ADs

None.

(c) Applicability

This AD applies to Honeywell International, Inc. ALF502L–2C; ALF502R–3; ALF502R–3A; ALF502R–5; LF507–1F; and LF507–1H turbofan engines.

(d) Unsafe Condition

This AD was prompted by two reports of engines experiencing uncontained release of low-pressure (LP) turbine blades. We are issuing this AD to prevent LP turbine overspeed leading to uncontained release of the LP turbine blades and damage to the airplane.

(e) Compliance

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

(f) Initial Check of the Overspeed Trip System

Within 30 operating hours after the effective date of this AD, perform an initial check of the overspeed trip system, in accordance with the applicable paragraphs for your engine as follows:

(1) ALF502L–2C Engines

(i) With engine operating at 65 percent NL (N1) speed (28 to 30 percent if overspeed controller 2–303–052–04 or later is installed), pull toggle lever of cockpit OVERSPEED TEST/RESET switch and hold in the OVERSPEED TEST position.

(ii) Activation of the engine overspeed system shall be verified by:

(A) Engine OVERSPEED TRIP light illuminated in cockpit.

(B) Reduction of engine NH (N2) speed.

(C) When engine NH (N2) speed begins to decrease, retract engine power lever to fuel cutoff position and turn off fuel boost pumps.

(D) Release lever of engine cockpit OVERSPEED TEST/RESET Switch.

(E) When engine is completely shut down, reset the engine Overspeed System by momentarily holding the engine cockpit OVERSPEED TEST/RESET switch on the RESET position.

(F) If engine does not shut down, manually shut down engine and perform a detailed functional test of the overspeed system. Guidance on performing a detailed functional test of the overspeed system can be found in the applicable engine maintenance manual instructions.

(2) ALF502R–3; ALF502R–3A; ALF502R–5, and LF507–1H Engines

(i) With engine operating at ground idle, set engine NL (N1) speed to 30 to 35 percent.

(ii) Press cockpit OVERSPEED TEST switch and hold.

(iii) Activation of the engine overspeed system shall be verified by:

(A) Engine OVERSPEED TRIP light illuminated in cockpit.

(B) Shutdown of the engine [zero NH (N2) speed].

(iv) Release cockpit OVERSPEED TEST switch and retract power lever to fuel cutoff position.

(v) When the engine is completely shut down, reset the engine overspeed system.

(vi) If engine does not shut down, manually shut down engine and perform a detailed functional test of the overspeed system. Guidance on performing a detailed functional test of the overspeed system can be found in the applicable engine manual instructions.

(3) LF507–1F Engines

(i) With engine operating at ground idle, set engine NL (N1) speed to 30 to 35 percent.

(ii) Activate cockpit overspeed test circuit (GRND TEST ENG OVSPD).

(iii) After NL (N1) speed begins to decay, retard the throttle to the fuel cutoff position.

(iv) Verify the following conditions:

(A) Engine shutdown.

(B) Overspeed system light (ENG OVSPD) is illuminated in cockpit.

(v) Reset overspeed system circuit power.

(vi) If engine does not shut down, manually shut down engine and perform a detailed functional test of the overspeed system. Guidance on performing a detailed functional test of the overspeed system can be found in the applicable engine manual instructions.

(g) Repetitive Checks of the Overspeed Trip System

(1) For ALF502L–2C engines, perform repetitive checks of the overspeed trip system at 100-hour intervals of operation, as specified in paragraph (f)(1) of this AD.

(2) For ALF502R–3; ALF502R–3A; ALF502R–5; and LF507–1H engines, perform repetitive checks of the overspeed trip system once every flight day, as specified in paragraph (f)(2) of this AD.

(3) For LF507–1F engines, perform repetitive checks of the overspeed trip system once every flight day, as specified in paragraph (f)(3) of this AD.

(h) Definition

For the purpose of this AD, a flight day is a 24-hour period during which at least one flight is indicated.

(i) Signing Off of Daily Repetitive Checks

Upon starting the daily repetitive checks, only one sign-off is required attesting to the daily check implementation.

(j) Alternative Methods of Compliance (AMOCs)

The Manager, Los Angeles Aircraft Certification Office, may approve AMOCs for this AD. Use the procedures found in 14 CFR 39.19 to make your request.

(k) Related Information

For more information about this AD, contact Robert Baitoo, Aerospace Engineer, Los Angeles Aircraft Certification Office, FAA, 3960 Paramount Blvd., Lakewood, CA 90712; phone: 562–627–5245; fax: 562–627–5210; email: *robert.baitoo@faa.gov.*

Issued in Burlington, Massachusetts, on May 23, 2012.

Peter A. White,

Manager Engine & Propeller Directorate, Aircraft Certification Service.

[FR Doc. 2012–13082 Filed 5–30–12; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF COMMERCE

Bureau of Industry and Security

15 CFR Part 748

Applications (Classification, Advisory, and License) and Documentation

CFR Correction

■ In Title 15 of the Code of Federal Regulations, Parts 300 to 799, revised as of April 1, 2012, on page 459, in Supplement 7 to part 748, in the fourth column of the table, the two entries for ''National Semiconductor Hong Kong Limited'' are removed.

[FR Doc. 2012–13246 Filed 5–30–12; 8:45 am]

BILLING CODE 1505–01–D

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

21 CFR Parts 510, 516, 520, 522, and 558

[Docket No. FDA–2012–N–0002]

New Animal Drugs; Altrenogest; Dexamethasone; Florfenicol

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 actions for new animal drug applications (NADAs) and abbreviated new animal drug applications (ANADAs) during April 2012. FDA is also informing the public of the availability of summaries of the basis of approval and of environmental review documents, where applicable.

DATES: This rule is effective May 31, 2012.

FOR FURTHER INFORMATION CONTACT:
George K. Haibel, Center for Veterinary Medicine (HFV–6), Food and Drug Administration, 7519 Standish Pl., Rockville, MD 20855, 240–276–9019, *george.haibel@fda.hhs.gov.*

SUPPLEMENTARY INFORMATION: FDA's Center for Veterinary Medicine (CVM) is adopting use of a monthly **Federal Register** document to codify approval actions for new animal drug applications (NADAs) and abbreviated new animal drug applications (ANADAs). CVM will no longer publish a separate rule for each action. This approach will allow a more efficient use of available resources.

In this document, FDA is amending the animal drug regulations to reflect the original and supplemental approval actions during April 2012, as listed in table 1 of this document. FDA is also informing the public of the availability, where applicable, of environmental review documents required under the National Environmental Policy Act (NEPA) and, for actions requiring review of safety or effectiveness data, summaries of the basis of approval (FOI Summaries) under the Freedom of Information Act (FOIA). These public documents 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. Persons with access to the Internet may obtain these documents at the CVM FOIA Electronic Reading Room: *http://www.fda.gov/AboutFDA/CentersOffices/OfficeofFoods/CVM/CVMFOIAElectronicReadingRoom/default.htm.*

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.

TABLE 1—ORIGINAL AND SUPPLEMENTAL NADAS AND ANADAS APPROVED DURING APRIL 2012

NADA/ ANADA	Sponsor	New animal drug product name	Action	21 CFR Section	FOIA summary	NEPA review
141–246	Intervet, Inc., 556 Morris Ave., Summit, NJ 07901.	AQUAFLOR (florfenicol) Type A medicated article.	Supplemental approval to: (1) Increase the permitted concentrations in Type C feeds; (2) add an indication for the control of mortality due to columnaris disease associated with *Flavobacterium columnare;* (3) add an indication for the control of mortality due to streptococcal septicemia associated with *Streptococcus iniae* in freshwater-reared warmwater finfish; and (4) increase the withdrawal period to 15 days. This approval renders § 516.1215 obsolete.	516.1215, 558.261.	yes	EA/FONSI.[1]
200–456	Med-Pharmex, Inc., 2727 Thompson Creek Rd., Pomona, CA 91767–1861.	Dexamethasone Injectable Solution.	Original approval of a generic copy of NADA 012–559.	522.540	yes	CE.[2]
200–481	Ceva Sante Animale, 10 Avenue de la Ballastière, 33500 Libourne, France.	ALTRESYN (altrenogest) Solution 0.22%.	Original approval of a generic copy of NADA 131–310.	520.48	yes	CE.[2]

[1] Based on its review of an environmental assessment (EA) submitted by the sponsor, the Agency has concluded that this action will not have a significant impact on the human environment and that an environmental impact statement is not required. A finding of no significant impact (FONSI) has been prepared.

[2] The Agency has determined under 21 CFR 25.33 that this action is categorically excluded (CE) from the requirement to submit an EA or an environmental impact statement (EIS) because it is of a type that does not individually or cumulatively have a significant effect on the human environment.

List of Subjects

21 CFR Part 510

Administrative practice and procedure, Animal drugs, Labeling, Reporting and recordkeeping requirements.

21 CFR Part 516

Administrative practice and procedure, Animal drugs, Confidential business information, Reporting and recordkeeping requirements.

21 CFR Parts 520 and 522

Animal drugs.

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 parts 510, 516, 520, 522, and 558 are amended as follows:

PART 510—NEW ANIMAL DRUGS

■ 1. The authority citation for 21 CFR part 510 continues to read as follows:

Authority: 21 U.S.C. 321, 331, 351, 352, 353, 360b, 371, 379e.

■ 2. In § 510.600, in the table in paragraph (c)(1), alphabetically add an entry for ''Ceva Sante Animale''; and in the table in paragraph (c)(2), numerically add an entry for ''013744'' to read as follows:

§ 510.600 Names, addresses, and drug labeler codes of sponsors of approved applications.

* * * * *

(c) * * *

(1) * * *

Firm name and address	Drug labeler code
* * *	* *
Ceva Sante Animale, 10 Avenue de la Ballastière, 33500 Libourne, France	013744
* * *	* *

(2) * * *

Drug labeler code	Firm name and address
* *	* * *
013744	Ceva Sante Animale, 10 Avenue de la Ballastière, 33500 Libourne, France.
* *	* * *

PART 516—NEW ANIMAL DRUGS FOR MINOR USE AND MINOR SPECIES

■ 3. The authority citation for 21 CFR part 516 continues to read as follows:

Authority: 21 U.S.C. 360ccc–1, 360ccc–2, 371.

§ 516.1215 [Removed]

■ 4. Remove § 516.1215.

PART 520—ORAL DOSAGE FORM NEW ANIMAL DRUGS

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

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

■ 6. In § 520.48, revise paragraph (b) to read as follows:

§ 520.48 Altrenogest.

* * * * *

(b) *Sponsors.* See sponsor listings in § 510.600(c) of this chapter:

(1) No. 000061 for use as in paragraph (d) of this section.

(2) No. 013744 for use as in paragraph (d)(1) of this section.

* * * * *

PART 522—IMPLANTATION OR INJECTABLE DOSAGE FORM NEW ANIMAL DRUGS

■ 7. The authority citation for 21 CFR part 522 continues to read as follows:

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

■ 8. In § 522.540, revise the section heading and paragraphs (a)(2)(ii) and (a)(3)(iii) to read as follows:

§ 522.540 Dexamethasone.

(a) * * *

(2) * * *

(ii) *Sponsors.* See Nos. 054925 and 058005 for use as in paragraphs (a)(3)(i)(C), (a)(3)(i)(D), (a)(3)(ii)(A), and (a)(3)(iii) of this section.

(3) * * *

(iii) Do not use in horses intended for human food. Federal law restricts this drug to use by or on the order of a licensed veterinarian.

* * * * *

PART 558—NEW ANIMAL DRUGS FOR USE IN ANIMAL FEEDS

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

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

■ 10. In § 558.261, revise paragraphs (a)(2) and (c)(2)(i), and the table in paragraph (e)(2) to read as follows:

§ 558.261 Florfenicol.

(a) * * *

(2) 500 grams per kilogram for use as in paragraph (e)(2) of this section.

* * * * *

(c) * * *

(2) * * *

(i) For freshwater-reared finfish, must not exceed 15 days from the date of issuance.

* * * * *

(e) * * *

(2) * * *

Florfenicol in grams/ton of feed	Indications for use	Limitations
(i) 182 to 2,724	Catfish: For the control of mortality due to enteric septicemia of catfish associated with *Edwardsiella ictaluri*.	Feed as a sole ration for 10 consecutive days to deliver 10 to 15 milligrams (mg) florfenicol per kilogram (kg) of fish. Feed containing florfenicol shall not be fed for more than 10 days. Following administration, fish should be reevaluated by a licensed veterinarian before initiating a further course of therapy. A dose-related decrease in hematopoietic/lymphopoietic tissue may occur. The time required for hematopoietic/lymphopoietic tissues to regenerate was not evaluated. The effects of florfenicol on reproductive performance have not been determined. Feeds containing florfenicol must be withdrawn 15 days prior to slaughter.
(ii) 182 to 1,816	Freshwater-reared salmonids: For the control of mortality due to coldwater disease associated with *Flavobacterium psychrophilum* and furunculosis associated with *Aeromonas salmonicida*.	Feed as a sole ration for 10 consecutive days to deliver 10 mg florfenicol per kg of fish. Feed containing florfenicol shall not be fed for more than 10 days. Following administration, fish should be reevaluated by a licensed veterinarian before initiating a further course of therapy. The effects of florfenicol on reproductive performance have not been determined. Feeds containing florfenicol must be withdrawn 15 days prior to slaughter.

Florfenicol in grams/ ton of feed	Indications for use	Limitations
(iii) 182 to 2,724	Freshwater-reared finfish: For the control of mortality due to columnaris disease associated with *Flavobacterium columnare*.	Feed as a sole ration for 10 consecutive days to deliver 10 to 15 mg florfenicol per kg of fish for freshwater-reared warmwater finfish and 10 mg florfenicol per kg of fish for other freshwater-reared finfish. Feed containing florfenicol shall not be fed for more than 10 days. Following administration, fish should be reevaluated by a licensed veterinarian before initiating a further course of therapy. For catfish, a dose-related decrease in hematopoietic/lymphopoietic tissue may occur. The time required for hematopoietic/lymphopoietic tissues to regenerate was not evaluated. The effects of florfenicol on reproductive performance have not been determined. Feeds containing florfenicol must be withdrawn 15 days prior to slaughter.
(iv) 273 to 2,724	Freshwater-reared warmwater finfish: For the control of mortality due to streptococcal septicemia associated with *Streptococcus iniae*.	Feed as a sole ration for 10 consecutive days to deliver 15 mg florfenicol per kg of fish. Feed containing florfenicol shall not be fed for more than 10 days. Following administration, fish should be reevaluated by a licensed veterinarian before initiating a further course of therapy. For catfish, a dose-related decrease in hematopoietic/lymphopoietic tissue may occur. The time required for hematopoietic/lymphopoietic tissues to regenerate was not evaluated. The effects of florfenicol on reproductive performance have not been determined. Feeds containing florfenicol must be withdrawn 15 days prior to slaughter.

Dated: May 24, 2012.

Bernadette Dunham,

Director, Center for Veterinary Medicine.

[FR Doc. 2012–13095 Filed 5–30–12; 8:45 am]

BILLING CODE 4160–01–P

DEPARTMENT OF TRANSPORTATION

Federal Highway Administration

23 CFR Part 658

[FHWA Docket No. FHWA–2012–0037]

RIN 2125–AF45

Truck Size and Weight; Technical Correction

AGENCY: Federal Highway Administration (FHWA), Department of Transportation (DOT).

ACTION: Final rule; technical correction.

SUMMARY: This rule makes a technical correction to the regulations that govern Longer Combination Vehicles (LCV) for the States of Oregon and Nebraska. The amendments contained herein make no substantive changes to FHWA regulations, policies, or procedures.

DATES: This rule is effective July 2, 2012.

FOR FURTHER INFORMATION CONTACT: John Nicholas, Truck Size and Weight Program Manager, Office of Freight Management and Operations, (202) 366–2317; or Bill Winne, Office of the Chief Counsel, (202) 366–1397. Both are located at 1200 New Jersey Avenue SE., Washington, DC 20590. Office hours for FHWA are from 8 a.m. to 4:30 p.m., e.t., Monday through Friday, except Federal holidays.

SUPPLEMENTARY INFORMATION:

Electronic Access

An electronic copy of this document may be downloaded by accessing the Office of the Federal Register's home page at: *http://www.archives.gov* or the Government Printing Office's Web page at: *http://www.gpoaccess.gov/nara.*

Background

This rulemaking makes technical corrections to the regulations in appendix C of 23 CFR part 658 that govern length of trailers in Oregon and the length of permit duration in Nebraska. The regulations on LCV's were frozen as of July 1, 1991, in accordance with Section 1023 of the Intermodal Surface Transportation Efficiency Act (ISTEA) [1] but a provision was made available in 23 CFR 658.23(f) that requires the FHWA Administrator to review petitions to correct any errors in Appendix C. The States of Oregon and Nebraska have petitioned the Federal Highway Administrator to make corrections to items they found to be incorrect in accordance with 23 CFR 658.23(f), and certified those provisions were in effect as of July 1, 1991.

Oregon Department of Transportation petitioned the FHWA Administrator that the section of Appendix C that describes operational conditions for triple trailers on Oregon's Interstate highways is not accurate. Oregon's law that was in effect at the time Appendix C was adopted, June 1, 1991, required only that the trailers be ''* * * reasonably uniform in length,'' rather than of ''equal length'' as stated in Appendix C. The substitution of language, ''reasonably uniform in length,'' for the current ''of equal length,'' will correct the language and bring it into conformance with Oregon statutes of that time.[2]

Nebraska Department of Roads petitioned the FHWA Administrator to change 120 days for the maximum duration of a permit, as currently written in Appendix C, to allow 150 days for the maximum permit time as included in Nebraska Statutes in July 1991. The substitution of 150 days for the current 120 days will correct the language and bring it into conformance with Nebraska statutes of that time.[3]

Rulemaking Analyses and Notice

Under the Administrative Procedure Act (5 U.S.C. 553(b)), an agency may waive the normal notice and comment requirements if it finds, for good cause, that they are impracticable, unnecessary, or contrary to the public interest. The FHWA finds that notice and comment for this rule is unnecessary and contrary to the public interest because it will have no substantive impact, is technical in nature, and relates only to management, organization, procedure, and practice. The amendments to the rule are based upon the explicit language of statutes that were enacted subsequent to the promulgation of the rule. The FHWA does not anticipate receiving meaningful comments. States, local governments, motor carriers, and other transportation stakeholders rely upon the regulations corrected by this action. These corrections will reduce confusion

[1] Public Law 105–240, 105 Stat. 1914, 1951 (Dec. 18, 1991) (codified at 23 U.S.C. 127(d)).

[2] Oregon Vehicle Code 812.210 (1991–1992).

[3] Neb. Rev. Stat. 39–6,181 (Cum. Supp. 1986).

for these entities and should not be unnecessarily delayed. Accordingly, for the reasons listed above, the agencies find good cause under 5 U.S.C. 553(b)(3)(B) to waive notice and opportunity for comment.

Executive Order 12866 (Regulatory Planning and Review), Executive Order 13563 (Improving Regulation and Regulatory Review), and DOT Regulatory Policies and Procedures

The FHWA has determined that this action is not a significant regulatory action within the meaning of Executive Order 12866 or significant within the meaning of DOT regulatory policies and procedures. This action complies with Executive Orders 12866 and 13563 to improve regulation. It is anticipated that the economic impact of this rulemaking will be minimal. This rule only makes minor corrections that will not in any way alter the regulatory effect of 23 CFR part 658. Thus, this final rule will not adversely affect, in a material way, any sector of the economy. In addition, these changes will not interfere with any action taken or planned by another agency and will not materially alter the budgetary impact of any entitlements, grants, user fees, or loan programs.

Regulatory Flexibility Act

In compliance with the Regulatory Flexibility Act (Pub. L. 96–354, 5 U.S.C. 60l–612) FHWA has evaluated the effects of this action on small entities and has determined that the action will not have a significant economic impact on a substantial number of small entities. This final rule will not make any substantive changes to our regulations or in the way that our regulations affect small entities; it merely corrects technical errors. For this reason, the FHWA certifies that this action will not have a significant economic impact on a substantial number of small entities.

Unfunded Mandates Reform Act of 1995

This rule does not impose unfunded mandates as defined by the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4, March 22, 1995, 109 Stat. 48). This rule does not impose any requirements on State, local, or tribal governments, or the private sector and, thus, will not require those entities to expend any funds.

Executive Order 13132 (Federalism)

This action has been analyzed in accordance with the principles and criteria contained in Executive Order 13132, and FHWA has determined that this action does not have sufficient federalism implications to warrant the preparation of a federalism assessment. The FHWA has also determined that this action does not preempt any State law or State regulation or affect the States' ability to discharge traditional State governmental functions.

Executive Order 12372 (Intergovernmental Review)

The regulations implementing Executive Order 12372 regarding intergovernmental consultation on Federal programs and activities apply to these programs.

Paperwork Reduction Act

This action does not create any new information collection requirements for which a Paperwork Reduction Act submission to the Office of Management and Budget would be needed under the Paperwork Reduction Act of 1995, 44 U.S.C. 3501–3520.

National Environmental Policy Act

The FHWA has analyzed this action for the purpose of the National Environmental Policy Act of 1969 (42 U.S.C. 4321–4347) and has determined that this action will not have any effect on the quality of the environment.

Executive Order 13175 (Tribal Consultation)

The FHWA has analyzed this action under Executive Order 13175, dated November 6, 2000, and concluded that this rule will not have substantial direct effects on one or more Indian tribes; will not impose substantial direct compliance costs on Indian tribal government; and will not preempt tribal law. There are no requirements set forth in this rule that directly affect one or more Indian tribes. Therefore, a tribal summary impact statement is not required.

Executive Order 12988 (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.

Executive Order 13045 (Protection of Children)

Under Executive Order 13045, Protection of Children from Environmental Health and Safety Risks, this final rule is not economically significant and does not involve an environmental risk to health and safety that may disproportionally affect children.

Executive Order 12630 (Taking of Private Property)

This final 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.

Executive Order 13211 (Energy Effects)

This final rule has been analyzed under Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use. The FHWA has 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 this final rule is not likely to have a significant adverse effect on the supply, distribution, or use of energy.

Regulation Identification Number

A regulation identification number (RIN) is assigned to each regulatory action listed in the Unified Agenda of Federal Regulations. The Regulatory Information Service Center publishes the Unified Agenda in April and October of each year. The RINs contained in the heading of this document can be used to cross reference this action with the Unified Agenda.

List of Subjects in 23 CFR Part 658

Grant programs—transportation, Highways and roads, Motor carriers.

Issued on: May 17, 2012.

Victor M. Mendez,

Administrator.

In consideration of the foregoing, 23 CFR part 658 is amended as set forth below.

PART 658—TRUCK SIZE AND WEIGHT, ROUTE DESIGNATIONS—LENGTH, WIDTH AND WEIGHT LIMITATIONS

■ 1. The authority citation for part 658 continues to read as follows:

Authority: 23 U.S.C. 127 and 315; 49 U.S.C. 31111, 31112, and 31114; sec. 347, Pub. L. 108–7, 117 Stat. 419; sec. 756, Pub L. 109–59, 119 Stat. 1219; sec. 115, Pub. L. 109–115, 119 Stat. 2408; 49 CFR 1.48(b)(19) and (c)(19).

Appendix C to Part 658 [Amended]

■ 2. Amend Appendix C to Part 658 as follows:

■ A. Under ''State: Nebraska, Combination: Truck tractor and 2 trailing unites—LCV'' entry by removing the number ''120'' under ''Permit:'' in paragraph 4 and adding in its place the number ''150''.

■ B. Under ''State: Oregon, Combination: Truck tractor and 3 trailing units—LCV'' entry by removing the phrase ''equal length'' under ''Vehicle:'' in sentence 1 and adding in its place the phrase ''reasonably uniform in length''.

[FR Doc. 2012–13020 Filed 5–30–12; 8:45 am]

BILLING CODE 4910–22–P

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

24 CFR Part 985

[Docket No. FR–5532–F–02]

RIN 2577–AC76

Revision to the Section 8 Management Assessment Program Lease-Up Indicator

AGENCY: Office of the Assistant Secretary for Public and Indian Housing, HUD.

ACTION: Final rule.

SUMMARY: This final rule amends HUD's regulations for the Section 8 Management Assessment program (SEMAP), by revising the process by which HUD measures and verifies performance under the SEMAP lease-up indicator. Specifically, HUD amends the existing regulation to reflect that assessment of a public housing agency's (PHA) leasing indicator will be based on a calendar year cycle, rather than a fiscal year cycle, which would increase administrative efficiencies for PHAs. This rule also clarifies that units assisted under the voucher homeownership option or occupied under a project-based housing assistance payments (HAP) contract are included in the assessment of PHA units leased.

DATES: *Effective:* July 2, 2012.

FOR FURTHER INFORMATION CONTACT: Laure Rawson, Director, Housing Voucher Management and Operations Division, Office of Public Housing and Voucher Programs, Office of Public and Indian Housing, Department of Housing and Urban Development, 451 7th Street SW., Room 4216, Washington, DC 20410, telephone number 202–402–2425.

SUPPLEMENTARY INFORMATION:

I. Background—Proposed Rule

On September 23, 2011, HUD published in the **Federal Register** a proposed rule, at 76 FR 59069, that proposed to revise the process by which HUD measures and verifies performance under the SEMAP lease-up indicator. HUD initiated that proposal to align the SEMAP lease-up indicator with the process for measuring voucher management system leasing and cost data, which by statute must be done on a calendar year cycle.

As provided in the preamble to the proposed rule, the Consolidated Appropriations Act, 2005 (Pub. L. 108–447, 118 Stat. 2809, approved December 8, 2004) addressed the subject of voucher management system leasing and cost data. The 2005 Consolidated Appropriations Act stated, in relevant part, that ''the Secretary for the calendar year 2005 funding cycle shall renew such contracts for each public housing agency based on verified Voucher Management System (VMS) leasing and cost data.'' (See 118 Stat. 3295.) Following enactment of the 2005 Consolidated Appropriations Act, the Office of Public and Indian Housing (PIH) issued PIH Notice 2005–1, which provides that ''PHAs will receive monthly disbursements from HUD on the basis of the PHA's calculated calendar year budget.'' Since 2005, consistent with the 2005 appropriations act and the implementing notice, and consistent with subsequent appropriations acts, HUD has provided PHAs with renewal funding for their Housing Choice Voucher (HCV) program on a calendar year basis. At the beginning of each calendar year, PHAs are notified of their funding amounts for the calendar year, and they plan their voucher issuance and leasing according to that funding cycle.

As the preamble to the proposed rule further noted, in contrast to the process for measuring VMS leasing and cost data, the SEMAP lease-up indicator continues to measure a PHA's lease-up rate on a fiscal year basis. The use of a calendar year for renewal funding, while using a fiscal year system for SEMAP measurements, has resulted in increased complexity for PHAs administering the HCV program and programmatic inefficiency. To eliminate such complexity, and reduce inefficiency in the HCV program resulting from two processes based on different periods of measurement, HUD, through the September 23, 2011, rule, proposed to amend the SEMAP regulations to provide for the SEMAP lease-up indicator to be measured based on a calendar year funding cycle, rather than the existing fiscal year cycle. The September 23, 2011, rule also proposed to clarify that units assisted under the voucher homeownership option or occupied under a project-based voucher (PBV) housing assistance payments (HAP) contract are included in the assessment of PHA units leased. These homeownership units and project-based voucher units have always been included in the assessment, but this is not explicit in current regulations.

II. Public Comments on Proposed Rule

At the close of public comment period on October 24, 2011, HUD received five public comments. The commenters consisted of two individuals, two PHAs and an independent nonprofit institute. With the exception of one of the PHAs, the commenters supported the changes proposed by the September 23, 2011, rule. The two individual commenters expressed their support for the rule without proposing any additional changes, with one of the commenters stating that the change was long overdue. The other two commenters supporting the rule proposed additional changes, and the PHA that did not favor the change appears to have misunderstood some of the program requirements.

In response to public comment, HUD revised the proposed rule at this final rule stage, to clarify what allocated budget authority includes. With the exception of this change, no further changes were made. The following addresses the comments raised by the latter three commenters.

Comment: The Proposed Change Will Not Increase Efficiency. One of the PHA commenters stated that it is not clear how HUD's proposed regulatory change to the SEMAP lease-up indicator would be beneficial to PHAs, since the financial settlement is due at the end of the PHA's fiscal year. The commenter stated that the proposed rule missed the connection between fiscal year end and utilization. The commenter stated that, as a PHA, it has to track HCVs and funding on a fiscal year basis because it cannot over-utilize unit months at fiscal year end, since it would not be paid by HUD for those months. The commenter stated that by changing this indicator, the PHA will now have to perform double tracking at fiscal year-end for fiscal year-end settlement, and at calendar year-end for SEMAP, which is actually more work, and that all other SEMAP measures would be tracked on a fiscal year basis, creating more complexity and confusion. The commenter stated that the only way this change would be beneficial is if HUD moved the year end settlement for PHAs from fiscal year to calendar year end and moved all the SEMAP indicators to calendar year.

HUD Response: HUD has not required year-end settlement statements from PHAs ever since the issuance of PIH Notice 2006–3 (section 5), which rescinded the requirement to submit form HUD–52681, because the relevant information was being captured in the

VMS and Financial Assessment Subsystem.[1] This rescission applied to PHAs with fiscal years ending on or after December 31, 2004. In regard to overutilization, all HUD appropriations acts including and since 2005 have prohibited PHAs from using their renewal funding to support a total number of unit months that exceeds the agency's authorized level of units under contract. Notice PIH 2005–1 [2] and subsequent funding implementation notices have clarified that over-leasing applies to a calendar year and not a PHA's fiscal year. The Department sees no need to move the measurement period for other SEMAP indicators to a calendar year. They will continue to be assessed by fiscal year to coincide with the current SEMAP cycle.

Comment: PBV Units Should Not Be the Only Units Not Counted as Leased for SEMAP Evaluation. The other PHA commenter expressed appreciation for the rule's attempt to clarify the treatment of voucher homeownership units and PBV units in the lease-up indicator, but disagreed that only PBV units that are leased-up should be counted as leased for purposes of SEMAP evaluation. The commenter stated that a PHA has a contractual commitment to provide subsidies to those specific units in one or many PBV projects. The commenter recommended that PHAs have the option to include as ''unit-months-leased'' all PBV units that are under an Agreement to Enter into Housing Assistance Payment (AHAP) contract or HAP contract, whether occupied or not. The commenter stated that HUD has paid administrative fees for PBV units under contract (as reported in VMS) which, the commenter states, also supports counting them as leased in the SEMAP indicator. The commenter further stated that when a PHA's HCV utilization rate is high, the PHA should ''reserve'' HCVs so that they will be available when a project under an AHAP is completed and is ready to lease up, and that similarly, a project that is under a HAP contract represents a commitment by the PHA of that many HCVs, so the PHA may need to hold turnover HCVs so they will be available to assist new PBV residents as they qualify and move in. The commenter stated that in both of these situations, the PHA should not be penalized under SEMAP as ''underutilized,'' and all of the HCVs committed under the AHAP or HAP should be counted as leased-up, at the PHA's option.

This commenter also stated that HUD should also continue to make allowance for HCVs reserved for AHAP and HAP contacts when calculating renewal funding. The commenter stated that it recognizes that not all HCVs under an AHAP or HAP should be counted as leased for purposes of determining overutilization. HCVs are over-leased when a PHA has more ''unit-months leased'' over the course of a calendar year than the authorized number of ''unit-months available.'' The commenter stated that for that calculation, HUD should continue to count only those PBV units that are actually leased up, and then allow the PHA to exclude units with ''zero-HAP'' or fully abated rent. The commenter concluded by stating that SEMAP does not penalize a PHA for HCV overutilization, and the commenter supports continuing that approach.

HUD Response: The purpose of this rule is to change the leasing period from the PHA's fiscal year to the calendar year. The identification of which units are included in the SEMAP leasing indicator was clarified in the proposed rule, not changed. It is not the purpose of this rule to change the type of HCV units included or excluded in the indicator. HUD intends to issue another proposed rule that will more comprehensively address the utilization indicator, as well as other SEMAP indicators. HUD will consider these comments in the development of that proposed rule.

Comment: Clarify Whether HCVs Award for Special Programs Are Included in the SEMAP Lease-Up Indicator. The same PHA recommended that HUD further clarify SEMAP by stating whether HCVs awarded for special programs are or are not included in the lease-up indicator. The commenter stated that many of those programs (most of which were created after SEMAP began) have separate procedures or requirements that reduce the PHA's control over utilization, such as requiring referrals or services from other agencies. The commenter stated that SEMAP should not penalize the PHA if underutilization in those special programs reduces overall utilization. The commenter stated that it administers the following types of HCVs: Regular tenant-based HCVs; HCVs that the PHA has approved for PBV use (about 10 percent of its HCV allocation), disability HCVs (formerly Mainstream), HUD–Veterans Administration Supportive Housing (VASH) HCVs, and Family Unification Program (FUP) HCVs. The commenter requested that HUD advise if these HCVs are to be included in the SEMAP lease-up indicator. The commenter stated that subsidies for Section 8 Moderate Rehabilitation Single Room Occupancy (Mod Rehab SRO) units should not be evaluated under SEMAP, since these units are funded and operated separately from the other Section 8 programs.

HUD Response: The only special purpose HCVs that are excluded from the SEMAP leasing indicator are HUD–VASH HCVs. This exclusion was recorded in the *Section 8 Housing Choice Vouchers: Revised Implementation of the of the HUD–VA Supportive Housing Program* published in the **Federal Register** on March 23, 2012, at 77 FR 17086. No other special purpose HCVs have been excluded from the leasing indicator. Again, it is not the purpose of this rule to change the type of HCV units that are included or excluded in the indicator. However, when the broader SEMAP rule is developed, these comments will be considered. No Moderate Rehabilitation program units are included in any indicator under SEMAP.

Comment: Clarify Only New Increments of HCVs in the Assessed Calendar Year Are Exempt from Lease-up Measure. The nonprofit institute commenter stated that under the existing regulations, PHAs are effectively granted a 12-month grace period to lease new HCV increments. The commenter stated that the proposed rule intends to change this blanket 12-month grace period to a variable period and that PHAs would not be held accountable for leasing new HCVs for the remainder of the calendar year in which they are issued. The commenter stated that in exempting units from the baseline, the proposed rule did not clearly distinguish between renewal funding and ongoing units, on the one hand, and new increments. The commenter suggested that to clearly achieve this purpose, the final rule should modify the last sentence of proposed § 985.3(n)(1), by inserting the word ''initially'' in the first clause as follows: ''Units and funding initially contracted under an ACC during the assessed calendar year * * * are not included in the baseline number of voucher units.''

The commenter, in further support of this suggested change, stated that the proposed rule strikes a better balance than current policy in that it acknowledges both that the leasing-up of new increments may be delayed for reasons beyond the PHA's control and that the great majority of new HCVs require far less than 12 months to lease

[1] See *http://portal.hud.gov/hudportal/documents/huddoc?id=DOC_8980.pdf.*

[2] See *http://portal.hud.gov/hudportal/documents/huddoc?id=DOC_9075.pdf.*

up. The commenter further stated that the proposed SEMAP lease-up indicator appears to count all leased HCVs in the numerator, including those from new increments, while excluding those increments from the denominator during the grace period, thereby artificially raising the utilization rate for affected agencies. The commenter stated that shortening the grace period would reduce the effect of this bias, and is also more consistent with HUD's renewal funding policy in recent years that assumes that all tenant protection HCVs can be leased within 90 days of award. The commenter stated that while PHAs receiving new increments in the last quarter of the calendar year would in effect be held to a more demanding standard under the proposed rule, the impact on leasing performance is likely to be small and justified by the simplicity of a clear calendar year-based measure.

The commenter further states that for some types of new HCV awards made near the end of the calendar year, it may be desirable to allow a longer period for initial leasing than allowed under the proposed rule, and that this may be particularly true when PHAs are required to coordinate with service providers before issuing the new HCVs to special populations, such as in the case of VASH or FUP HCVs. The commenter offered that rushing the leasing of such HCVs may be short-sighted, and undermine the goal of promoting ongoing partnerships between PHAs and service-providing agencies.

The commenter concluded with the recommendation that the final rule allow HUD to exempt, on a case-by-case basis, particular HCV increments from the baseline for an additional calendar year when a longer period for initial leasing would advance the goals of the award.

HUD Response: The Department did not intend, through this rule, to change the period of time that new units are excluded from the utilization calculation. Accordingly, this language is clarified in the final rule. As pointed out by the commenter, to exclude the units just for the calendar year in which they were awarded causes units to be excluded for variable periods depending on the month they are awarded, and such exclusion would unfairly penalize PHAs that receive new allocations late in the assessed year. The Department appreciates the commenter's concerns that a 12-month period may be too long of a period for PHAs to be given to utilize new HCVs. These comments will be considered in the broader SEMAP rule that is currently under development. The Department will also consider the comments regarding the potential need for longer leasing time for HCVs that serve special populations or rely on third-party referrals, as well as granting extensions to certain increments on a case-by-case basis if doing so would advance the goals of the award.

Comment: Exempt Litigation HCV Units and Funding on a Temporary, not Permanent, Basis from the Lease-Up Measure. The nonprofit institute commenter suggested another change to be made at the final rule stage. The commenter stated that the proposed rule is somewhat ambiguous but appears to exempt units and funding obligated as part of litigation from the baseline number of HCVs permanently, and not just in the calendar year of initial issuance. The commenter stated that it is important to provide flexibility in the treatment of litigation HCVs, because past experience has shown that litigation-related HCV awards can take several years to be fully leased, due to litigation-imposed restrictions on the uses of the HCVs. The commenter stated that a permanent exemption is unnecessary to address this concern, and reduces the incentive to lease these HCVs once barriers have been overcome.

The commenter recommended that HUD provide temporary exclusions from PHAs' HCV baseline, on a case-by-case basis, for litigation HCVs.

HUD Response: While these comments are appreciated, the subject of this rulemaking is only the period of assessment for the leasing indicator. However, HUD will consider these comments in the development of the broader SEMAP rule.

Comment: Determination of Funds ''Allocated'' Should Include Certain Renewal Funding. The independent nonprofit institute commenter stated that a determination of funds ''allocated'' should include renewal funding for which PHAs are eligible, after proration, but that is not provided due to an offset of excess reserves (net restricted assets). The commenter stated that in 2008 and 2009, Congress directed HUD to offset renewal funding due PHAs under the prescribed renewal formula by excess unspent funds from prior years. (HUD requires PHAs to hold such reserves in a ''net restricted assets'' account.) The commenter stated that there is a high likelihood that HUD will be required or would opt to use similar policies in 2012 and future years, and that the premise of such an offset policy is that PHAs will in fact use the offset funds to support HCVs during the calendar year. The commenter stated that to align the measure of lease-up performance with Congressional intent, it is essential that funds offset are included in the determination of ''allocated budget authority'' that may be used as the denominator in the rating measure.

The commenter recommended that the final rule either should define ''allocated budget authority'' to include funds offset in determining the calendar year renewal allocation, or should add language regarding the inclusion of offset funds in the denominator of the measure.

HUD Response: HUD agrees that, for purposes of SEMAP, it is important to clarify what is considered in ''allocated budget authority.'' Therefore, the final rule has been revised to clarify what allocated budget authority includes.

Comment: Allow Credit for HCV Set-Aside for Project-Basing. The nonprofit institute commenter recommended that HUD give PHAs credit for HCVs set-aside for project-basing. The commenter stated that PHAs that commit to project-base HCVs in properties that are not immediately available for occupancy may have to reserve all or a portion of the promised HCVs and funding in order not to exceed the authorized HCV cap or available funds when the units become available. The commenter stated that whether a PHA has to ''shelve'' HCVs to meet project-basing commitments depends on the number of PBVs committed in relation to the size of the PHA's portfolio, its turnover rate, and other factors. The commenter stated that appropriations acts in recent years have recognized this reality by requiring HUD to adjust renewal funding allocations for PHAs that have not used a portion of their HCVs to meet project-basing commitments.

The commenter recommended that the measure of performance for the SEMAP lease-up indicator also should recognize this limited exception, to balance the vital policy of encouraging PHAs to serve the maximum number of families possible with the policy goals of encouraging mixed-income and supportive housing developments.

HUD Response: See HUD's response to the second comment.

III. Findings and Certifications

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. At the proposed rule stage, HUD certified that the proposed regulations would not have a significant economic impact on a substantial number of entities, and that assessment is not changed by this final rule. This rule is directed to increasing administrative efficiencies for PHAs, by aligning the cycle for renewal funding with the cycle for SEMAP measurements. This rule would also provide clarification for PHAs regarding units included in this measure.

Environmental Impact

This rule 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. This rule is limited to the means by which PHAs lease-up rates are measured. Accordingly, under 24 CFR 50.19(c)(1), this rule is categorically excluded from environmental review under the National Environmental Policy Act of 1969 (42 U.S.C. 4321).

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.

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 rule does not impose any federal mandates on any state, local, or tribal government, or on the private sector, within the meaning of UMRA.

List of Subjects in 24 CFR Part 985

Grant programs—housing and community development, Housing, Rent subsidies, Reporting and recordkeeping requirements.

Accordingly, for the reasons stated in the preamble, HUD amends 24 CFR part 985 as follows:

PART 985—SECTION 8 MANAGEMENT ASSESSMENT PROGRAM (SEMAP)

■ 1. The authority citation for part 985 continues to read as follows:

Authority: 42 U.S.C. 1437a, 1437c, 1437f, and 3535(d).

■ 2. Revise § 985.3(n) as follows:

§ 985.3 Indicators, HUD verification methods, and ratings.

* * * * *

(n) *Lease-up.* The provisions of this paragraph (n) apply to the first SEMAP certification due after July 2, 2012.

(1) *The indicator:* This indicator shows whether the PHA enters into HAP contracts for the number of the PHA's baseline voucher units (units that are contracted under a Consolidated ACC) for the calendar year that ends on or before the PHA's fiscal year or whether the PHA has expended its allocated budget authority for the same calendar year. Allocated budget authority will be based upon the PHA's eligibility, which includes budget authority obligated for the calendar year and any portion of HAP reserves attributable to the budget authority that was offset from reserves during the calendar year. Litigation units and funding will be excluded from this indicator, and new increments will be excluded for 12 months from the effective date of the increment on the Consolidated ACC. Units assisted under the voucher homeownership option and units occupied under a project-based HAP contract are included in the measurement of this indicator.

(2) *HUD verification method:* This method is based on the percent of units leased under a tenant-based or project-based HAP contract or occupied by homeowners under the voucher homeownership option during the calendar year that ends on or before the assessed PHA's fiscal year, or the percent of allocated budget authority expended during the calendar year that ends on or before the assessed PHA's fiscal year. The percent of units leased is determined by taking unit months leased under a HAP contract and unit months occupied by homeowners under the voucher homeownership option, as shown in HUD systems for the calendar year that ends on or before the assessed PHA fiscal year, and dividing that number by the number of unit months available for leasing based on the number of baseline units available at the beginning of the calendar year.

(3) *Rating:* (i) The percent of units leased or occupied by homeowners under the voucher homeownership option, or the percent of allocated budget authority expended during the calendar year that ends on or before the assessed PHA fiscal year was 98 percent or more. (20 points.)

(ii) The percent of units leased or occupied by homeowners under the voucher homeownership option, or the percent of allocated budget authority expended during the calendar year that ends on or before the assessed PHA fiscal year was 95 to 97 percent. (15 points.)

(iii) The percent of units leased or occupied by homeowners under the voucher homeownership option, or the percent of allocated budget authority expended during the calendar year that ends on or before the assessed PHA fiscal year was less than 95 percent. (0 points.)

* * * * *

Dated: May 23, 2012.

Sandra B. Henriquez,

Assistant Secretary for Public and Indian Housing.

[FR Doc. 2012–13198 Filed 5–30–12; 8:45 am]

BILLING CODE 4210–67–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

33 CFR Part 165

[Docket Number USCG–2012–0240]

RIN 1625–AA00

Safety Zone; Kemah Boardwalk Summer Season Fireworks, Galveston Bay, Kemah, TX

AGENCY: Coast Guard, DHS.

ACTION: Temporary final rule.

SUMMARY: The Coast Guard is establishing a temporary safety zone for the specified waters in Galveston Bay in the vicinity of Kemah, Texas within a 1000' radius around a fireworks barge. The safety zone is necessary to aid in the safety of mariners viewing the Kemah Boardwalk Summer Season Fireworks. During periods of enforcement, entry into the zone will not be permitted except as specifically authorized by the Captain of the Port Houston-Galveston or a designated representative.

DATES: This rule is effective from 8:30 p.m. on June 1, 2012 until 1 a.m. on January 1, 2013.

ADDRESSES: Documents mentioned in this preamble are part of docket [USCG–2012–0240]. To view documents mentioned in this preamble as being available in the docket, go to *http://www.regulations.gov,* type the docket number in the ''SEARCH'' box and click ''SEARCH.'' Click on Open Docket Folder on the line associated with this rulemaking. You may also visit the Docket Management Facility in Room W12–140 on the ground floor of the Department of Transportation West Building, 1200 New Jersey Avenue SE., Washington, DC 20590, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

FOR FURTHER INFORMATION CONTACT: If you have questions on this rule, call or email LT Margaret Brown, Sector Houston-Galveston Waterways Management Branch, U.S. Coast Guard; telephone (713) 678–9001, email *Margaret.A.Brown@uscg.mil.* If you have questions on viewing or submitting material to the docket, call Renee V. Wright, Program Manager, Docket Operations, telephone (202) 366–9826.

SUPPLEMENTARY INFORMATION:

Table of Acronyms

DHS Department of Homeland Security
FR **Federal Register**
NPRM Notice of Proposed Rulemaking

A. Regulatory History and Information

The Coast Guard is issuing this final rule without prior notice and opportunity to comment pursuant to authority under section 4(a) of the Administrative Procedure Act (APA) (5 U.S.C. 553(b)). This provision authorizes an agency to issue a rule without prior notice and opportunity to comment when the agency for good cause finds that those procedures are ''impracticable, unnecessary, or contrary to the public interest.'' Under 5 U.S.C. 553(b)(B), the Coast Guard finds that good cause exists for not publishing a notice of proposed rulemaking (NPRM) with respect to this rule. Delaying the effective date by first publishing an NPRM would be contrary to the safety zone's intended objective since immediate action is needed to protect person's and vessels against the hazards associated with fireworks displays on navigable waters. Such hazards include premature detonations, dangerous detonations, dangerous projectiles and falling or burning debris.

For the same reasons, under 5 U.S.C. 553(d)(3), the Coast Guard finds that good cause exists for making this rule effective less than 30 days after publication in the **Federal Register**. For firework displays occurring without a full 30 days notice, it would be impracticable to interfere with the fireworks displays or delay the immediate action needed to protect mariners viewing the fireworks displays. This rulemaking provides 30 days notice for firework displays occurring after July 2, 2012.

B. Basis and Purpose

The legal basis and authorities for this rule are found in 33 U.S.C. 1266, 1231, 46 U.S.C. Chapter 701, 3306, 3703; 50 U.S.C. 191, 195; 33 CFR 1.05–1, 6.04–1, 6.04–6, and 160.5; Pub. L. 107–295, 116 Stat. 2064; and Department of Homeland Security Delegation No. 0170.1, which collectively authorize the Coast Guard to establish and define regulatory safety zones.

The Kemah Boardwalk Summer Season Fireworks will feature fireworks being launched from a barge. It has been determined that a safety zone is necessary to keep recreational vessels clear of any potential hazards associated with the launching of fireworks.

This temporary safety zone provides protection for persons and property, including spectators, persons working the displays, and others that may be in the area during enforcement periods of this temporary safety zone, from the hazards associated with fireworks displays on or over the waterway.

C. Discussion of the Rule

The Coast Guard is establishing a temporary safety zone in Galveston Bay in the vicinity of Kemah, Texas within a 1000' radius around a fireworks barge located at approximate Latitude 29°32′57″ N, Longitude 095°00′31″ W. Entry into the zone will not be permitted except as specifically authorized by the Captain of the Port Houston-Galveston or a designated representative. They may be contacted at ''Sector Houston-Galveston'' on VHF–FM Channels 16, or by phone at (713) 671–5113. Requests to enter into and/or pass through the safety zone will be reviewed on a case-by-case basis.

The temporary safety zone will be enforced during the following dates and times: from 8:30 p.m. until 11:30 p.m. on June 1, 8, 15, 22, and 29, 2012; July 4, 6, 13, 20, and 27, 2012; November 3, 2012; and from 9 p.m. on December 31, 2012 until 1 a.m. on January 1, 2013. Notifications of changes in enforcement periods will be made through broadcast notice to mariners.

D. Regulatory Analyses

We developed this rule after considering numerous statutes and executive orders related to rulemaking. Below we summarize our analyses based on a number of these statutes or executive orders.

1. Regulatory Planning and Review

This rule is not a significant regulatory action under section 3(f) of Executive Order 12866, Regulatory Planning and Review, as supplemented by Executive Order 13563, Improving Regulation and Regulatory Review, and does not require an assessment of potential costs and benefits under section 6(a)(3) of Executive Order 12866 or under section 1 of Executive Order 13563. The Office of Management and Budget has not reviewed it under those Orders. This regulation is not a significant regulatory action because enforcements of the safety zone will only be in effect for a brief period of time. Notifications to the marine community will be made through broadcast notice to mariners and electronic mail. The safety zone will only affect recreational vessels and deviation from the restrictions may be requested from the COTP or designated representative and will be considered on a case-by-case basis. The impacts on routine navigation are expected to be minimal.

2. Impact on Small Entities

The Regulatory Flexibility Act of 1980 (RFA), 5 U.S.C. 601–612, as amended, requires federal agencies to consider the potential impact of regulations on small entities during rulemaking. 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 would affect the following entities, some of which might be small entities: the owners or operators of recreational vessels intending to transit or anchor in a portion of the Clear Creek/Kemah Channel from 8:30 p.m. until 11:30 p.m. on June 1, 8, 15, 22, and 29, 2012; July 4, 6, 13, 20, and 27, 2012; November 3, 2012; and from 9 p.m. on December 31, 2012 until 1 a.m. on January 1, 2013.

The impact would not be significant to small entities as each safety zone will only affect recreational vessels transiting the Clear Creek/Kemah Channel for a short period of time. Before activation of the zone, broadcast notices to mariners will be issued to users of the channel.

3. 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 this rule. If the rule would 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**, above.

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). The Coast Guard will not retaliate against small entities that question or complain about this rule or any policy or action of the Coast Guard.

4. Collection of Information

This rule will not call for a new collection of information under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501–3520).

5. Federalism

A rule has implications for federalism under Executive Order 13132, Federalism, if it has a substantial direct effect on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government. We have analyzed this rule under that Order and determined that this rule does not have implications for federalism.

6. Protest Activities

The Coast Guard respects the First Amendment rights of protesters. Protesters are asked to contact the person listed in the **FOR FURTHER INFORMATION CONTACT** section to coordinate protest activities so that your message can be received without jeopardizing the safety or security of people, places or vessels.

7. Unfunded Mandates Reform Act

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

8. Taking of Private Property

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

9. 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.

10. 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.

11. 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.

12. Energy Effects

This action is not a ''significant energy action'' under Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use.

13. Technical Standards

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

14. Environment

We have analyzed this rule under Department of Homeland Security Management Directive 023–01 and Commandant Instruction M16475.lD, which guide the Coast Guard in complying with the National Environmental Policy Act of 1969 (NEPA) (42 U.S.C. 4321–4370f), and have determined that this action is one of a category of actions that do not individually or cumulatively have a significant effect on the human environment. This rule involves the establishment of a safety zone for the protection of human life. This rule is categorically excluded from further review under paragraph 34(g) of Figure 2–1 of the Commandant Instruction. An environmental analysis checklist supporting this determination and a Categorical Exclusion Determination are available in the docket where indicated under **ADDRESSES**. We seek any comments or information that may lead to the discovery of a significant environmental impact from this rule.

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. 1231; 46 U.S.C. Chapter 701, 3306, 3703; 50 U.S.C. 191; 33 CFR 1.05–1, 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. A new temporary § 165.T08–0240 is added to read as follows:

§ 165.T08–0240 Safety Zone; Kemah Boardwalk Summer Season Fireworks, Galveston Bay, Kemah, TX.

(a) *Location.* The following area is a safety zone: Galveston Bay within a 1000' radius around a fireworks barge located at approximate Latitude 29°32′57″ N, Longitude 095°00′31″ W.

(b) *Enforcement dates.* The temporary safety zone will be enforced during the following dates and times: From 8:30 p.m. until 11:30 p.m. on June 1, 8, 15, 22, and 29, 2012; July 4, 6, 13, 20, and 27, 2012; November 3, 2012; and from 9 p.m. on December 31, 2012 until 1 a.m. on January 1, 2013. Notifications of changes in enforcement periods will be made through broadcast notice to mariners.

(c) *Regulations.* (1) In accordance with the general regulations in § 165.23 of this part, entry into this zone is prohibited unless authorized by the Captain of the Port Houston-Galveston.

(2) Persons or vessels requiring entry into or passage through the zone must request permission from the Captain of the Port Houston-Galveston, or a designated representative. They may be contacted at ''Sector Houston-Galveston'' on VHF–FM Channels 16, or by phone at (713) 671–5113. Requests to enter into and/or pass through the safety zone will be reviewed on a case-by-case basis. All persons and vessels shall comply with the instructions of the Captain of the Port Houston-Galveston

and designated on-scene U.S. Coast Guard patrol personnel. On-scene U.S. Coast Guard patrol personnel include commissioned, warrant, and petty officers of the U.S. Coast Guard.

(d) *Informational Broadcasts.* Notifications of changes in enforcement periods and changes to the safety zone will be made through broadcast notice to mariners.

Dated: May 9, 2012.

James H. Whitehead,

Captain, U.S. Coast Guard, Captain of the Port Houston-Galveston.

[FR Doc. 2012–13160 Filed 5–30–12; 8:45 am]

BILLING CODE 9110–04–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

33 CFR Part 165

[Docket No. USCG–2012–0339]

Safety Zones: Fireworks Displays in the Captain of the Port Columbia River Zone

AGENCY: Coast Guard, DHS.

ACTION: Notice of enforcement of regulation.

SUMMARY: The Coast Guard will enforce the safety zones for fireworks displays in the Sector Columbia River Captain of the Port Zone from May 2012 through September 2012. This action is necessary to ensure the safety of the crews onboard the vessels displaying the fireworks, the maritime public, and all other observers. During the enforcement period for each specific safety zone, no person or vessel may enter or remain in the safety zone without permission of the Captain of the Port Columbia River or his designated representative.

DATES: The regulations in 33 CFR Part 165.1315 will be enforced as listed in the **SUPPLEMENTARY INFORMATION** section.

FOR FURTHER INFORMATION CONTACT: If you have questions on this notice, call or email ENS Ian McPhillips, Waterways Management Division, MSU Portland, Coast Guard; telephone 503–240–9319, email *Ian.P.McPhillips@uscg.mil.*

SUPPLEMENTARY INFORMATION: The Coast Guard will enforce the safety zone regulation in 33 CFR 165.1315 for fireworks displays in the Columbia River Captain of the Port Zone during the dates and times listed as follows:

(1) Portland Rose Festival Fireworks Display, Portland, OR: May 25, 2012 from 8:30 p.m. until 11:30 p.m.

(2) Tri-City Chamber of Commerce Fireworks Display, Columbia Park, Kennewick, WA: July 4, 2012 from 8:30 p.m. until 11:30 p.m.

(3) Cedco Inc. Fireworks Display, North Bend, OR: July 3, 2012 from 8:30 p.m. until 11:30 p.m.

(4) Astoria 4th of July Fireworks, Astoria, OR: July 4, 2012 from 8:30 p.m. until 11:30 p.m.

(5) Oregon Food Bank Blues Festival Fireworks, Portland, OR: July 4, 2012 from 8:30 p.m. until 11:30 p.m.

(6) Oregon Symphony Concert Fireworks Display, Portland, OR: August 30, 2012 from 8:30 p.m. until 11:30 p.m.

(7) Florence Chamber 4th of July Fireworks Display, Florence, OR: July 4, 2012 from 9 p.m. until 11 p.m.

(8) Oaks Park July 4th Celebration, Portland, OR: July 4, 2012 from 9 p.m. until 11 p.m.

(9) Rainier Days Fireworks Celebration, Rainier, OR: July 14, 2012 from 9 p.m. until 11 p.m.

(10) Independence Day at the Port, Ilwaco, WA: July 7, 2012 from 10 p.m. until 10:30 p.m.

(11) Milwaukie Centennial Fireworks Display, Milwaukie, OR: July 28, 2012 from 9 p.m. until 11 p.m.

(12) Splash Aberdeen Waterfront Festival, Aberdeen, WA: July 4, 2012 from 9 p.m. until 11 p.m.

(13) City of Coos Bay July 4th Celebration, Coos Bay, OR: July 4, 2012 from 9:00 p.m. until 11:00 p.m.

(14) Arlington Chamber of Commerce Fireworks Display, Arlington, OR: July 4, 2012 from 8:30 p.m. until 11:30 p.m.

(15) East County 4th of July Fireworks, Gresham, OR: July 4, 2012 from 8:30 p.m. until 11:30 p.m.

(16) Port of Cascade Locks July 4th Fireworks Display, Cascade Locks, OR: July 4, 2012 from 8:30 p.m. until 11:30 p.m.

(17) Astoria Regatta Association Fireworks Display, Astoria, OR: August 11, 2012 from 8:30 p.m. until 11:30 p.m.

(18) City of Washougal July 4th Fireworks Display, Washougal, WA: July 4, 2012 from 8:30 p.m. until 11:30 p.m.

(19) City of St. Helens 4th of July Fireworks Display, St. Helens, OR: July 4, 2012 from 8:30 p.m. until 11:30 p.m.

(20) Waverly Country Club 4th of July Fireworks Display, Milwaukie, OR: July 4, 2012 from 8:30 p.m. until 11:30 p.m.

(21) Booming Bay Fireworks, Westport, WA: July 4, 2012 from 8:30 until 11:30 p.m.

(22) Hood River 4th of July, Hood River, OR: July 4, 2012 from 8:30 p.m. until 11:30 p.m.

(23) Rufus 4th of July Fireworks, Rufus, OR: July 4, 2012 from 8:30 p.m. until 11:30 p.m.

Under the provisions of 33 CFR part 165.1315 and 33 CFR part 165 subparts C, no person or vessel may enter or remain in the safety zones without permission of the Captain of the Port Columbia River or his designated representative. See 33 CFR 165.1315 and 33 CFR 165 Subparts C for additional information and prohibitions. Persons or vessels wishing to enter the safety zones may request permission to do so from the Captain of the Port Columbia River or his designated representative via VHF Channel 16 or 13. The Coast Guard may be assisted by other Federal, State, or local enforcement agencies in enforcing this regulation.

This notice is issued under authority of 33 CFR 165.1315 and 5 U.S.C. 552(a). In addition to this notice in the **Federal Register**, the Coast Guard will provide the maritime community with notification of this enforcement period via the Local Notice to Mariners.

Dated: May 3, 2012.

B.C. Jones,

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

[FR Doc. 2012–13032 Filed 5–30–12; 8:45 am]

BILLING CODE 9110–04–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 9 and 721

[EPA–HQ–OPPT–2011–0942; FRL–9350–3]

RIN 2070–AB27

Significant New Use Rule on a Certain Chemical Substance; Withdrawal of Significant New Use Rule

AGENCY: Environmental Protection Agency (EPA).

ACTION: Withdrawal of final rule.

SUMMARY: EPA is withdrawing a significant new use rule (SNUR) promulgated under the Toxic Substances Control Act (TSCA) for a chemical substance identified generically as C15 olefins, which was the subject of premanufacture notice (PMN) P–11–511. EPA published this SNUR using direct final rulemaking procedures. EPA received a notice of intent to submit adverse comments on the rule. Therefore, the Agency is withdrawing this SNUR, as required under the expedited SNUR rulemaking process. EPA intends to publish a proposed SNUR for the chemical substance under separate notice and comment procedures.

DATES: This final rule is effective June 4, 2012.

FOR FURTHER INFORMATION CONTACT: *For technical information contact:* Kenneth Moss, Chemical Control Division (7405M), Office of Pollution Prevention and Toxics, Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460–0001; telephone number: (202) 564–9232; email address: *moss.kenneth@epa.gov.*

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

SUPPLEMENTARY INFORMATION:

I. Does this action apply to me?

A list of potentially affected entities is provided in the **Federal Register** of April 4, 2012 (77 FR 20296) (FRL–9333–3). If you have questions regarding the applicability of this action to a particular entity, consult the technical person listed under **FOR FURTHER INFORMATION CONTACT**.

II. What rule is being withdrawn?

In the **Federal Register** of April 4, 2012 (77 FR 20296), EPA issued several direct final SNURs, including a SNUR for the chemical substance that is the subject of this withdrawal. These direct final rules were issued pursuant to the procedures in 40 CFR part 721, subpart D. In accordance with § 721.160(c)(3)(ii), EPA is withdrawing the rule issued for a chemical substance identified generically as C15 olefins, which was the subject of PMN P–11–511, because the Agency received a notice of intent to submit adverse comments. EPA intends to publish a proposed SNUR for this chemical substance under separate notice and comment procedures.

For further information regarding EPA's expedited process for issuing SNURs, interested parties are directed to 40 CFR part 721, subpart D, and the **Federal Register** of July 27, 1989 (54 FR 31314). The record for the direct final SNUR for this chemical substance that is being withdrawn was established at EPA–HQ–OPPT–2011–0942. That record includes information considered by the Agency in developing this rule and the notice of intent to submit adverse comments.

III. How do I access the docket?

To access the electronic docket, please go to *http://www.regulations.gov* and follow the online instructions to access docket ID number EPA–HQ–OPPT–2011–0942. Additional information about the Docket Facility is provided under **ADDRESSES** in the **Federal Register** of April 4, 2012 (77 FR 20296). If you have questions, consult the technical person listed under **FOR FURTHER INFORMATION CONTACT**.

IV. Statutory and Executive Order Reviews

This final rule revokes or eliminates an existing regulatory requirement and does not contain any new or amended requirements. As such, the Agency has determined that this withdrawal will not have any adverse impacts, economic or otherwise. The statutory and executive order review requirements applicable to the direct final rule were discussed in the **Federal Register** of April 4, 2012 (77 FR 20296). Those review requirements do not apply to this action because it is a withdrawal and does not contain any new or amended requirements.

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 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 the rule in the **Federal Register**. This rule is not a ''major rule'' as defined by 5 U.S.C. 804(2).

List of Subjects

40 CFR Part 9

Environmental protection, Reporting and recordkeeping requirements.

40 CFR Part 721

Environmental protection, Chemicals, Hazardous substances, Reporting and recordkeeping requirements.

Dated: May 18, 2012.

Maria J. Doa,

Director, Chemical Control Division, Office of Pollution Prevention and Toxics.

Therefore, 40 CFR parts 9 and 721 are amended as follows:

PART 9—[AMENDED]

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

Authority: 7 U.S.C. 135 *et seq.*, 136–136y; 15 U.S.C. 2001, 2003, 2005, 2006, 2601–2671; 21 U.S.C. 331j, 346a, 348; 31 U.S.C. 9701; 33 U.S.C. 1251 *et seq.*, 1311, 1313d, 1314, 1318, 1321, 1326, 1330, 1342, 1344, 1345 (d) and (e), 1361; E.O. 11735, 38 FR 21243, 3 CFR, 1971–1975 Comp. p. 973; 42 U.S.C. 241, 242b, 243, 246, 300f, 300g, 300g–1, 300g–2, 300g–3, 300g–4, 300g–5, 300g–6, 300j–1, 300j–2, 300j–3, 300j–4, 300j–9, 1857 *et seq.*, 6901–6992k, 7401–7671q, 7542, 9601–9657, 11023, 11048.

■ 2. The table in § 9.1 is amended by removing under the undesignated center heading ''Significant New Uses of Chemical Substances'' § 721.10291.

PART 721—[AMENDED]

■ 3. The authority citation for part 721 continues to read as follows:

Authority: 15 U.S.C. 2604, 2607, and 2625(c).

§ 721.10291 [Removed]

■ 4. Remove § 721.10291.

[FR Doc. 2012–12920 Filed 5–30–12; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 62

[EPA–R05–OAR–2012–0312; FRL–9679–6]

Direct Final Negative Declaration and Withdrawal of Large Municipal Waste Combustors State Plan for Designated Facilities and Pollutants: Illinois

AGENCY: Environmental Protection Agency (EPA).

ACTION: Direct final rule.

SUMMARY: EPA is taking direct final action to approve Illinois' negative declaration and request for EPA withdrawal of its 111(d)/129 State Plan to control air pollutants from ''Large Municipal Waste Combustors'' (LMWC).

DATES: This direct final rule will be effective July 30, 2012, unless EPA receives adverse comments by July 2, 2012. If adverse comments are received, EPA will publish a timely withdrawal of the direct final rule in the **Federal Register** informing the public that the rule will not take effect.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–R05–OAR–2012–0312, by one of the following methods:

1. *www.regulations.gov:* Follow the on-line instructions for submitting comments.
2. *Email: nash.carlton@epa.gov.*
3. *Fax:* (312) 692–2543.
4. *Mail:* Carlton T. Nash, Chief, Toxics and Global Atmosphere Section, Air Toxics and Assessment Branch (AT–18J), U.S. Environmental Protection Agency, 77 West Jackson Boulevard, Chicago, Illinois 60604.
5. *Hand Delivery:* Carlton T. Nash, Chief, Toxics and Global Atmosphere Section, Air Toxics and Assessment Branch (AT–18J), U.S. Environmental

Protection Agency, 77 West Jackson Boulevard, Chicago, Illinois 60604. Such deliveries are only accepted during the Regional Office normal hours of operation, and special arrangements should be made for deliveries of boxed information. The Regional Office official hours of business are Monday through Friday, 8:30 a.m. to 4:30 p.m. excluding Federal holidays.

Instructions: Direct your comments to Docket ID No. EPA–R05–OAR–2012–0312. 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 email. 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 email comment directly to EPA without going through *www.regulations.gov* your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. 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. Publicly available docket materials are available either electronically in *www.regulations.gov* or in hard copy at the Environmental Protection Agency, Region 5, Air and Radiation Division, 77 West Jackson Boulevard, Chicago, Illinois 60604. This Facility is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding Federal holidays. We recommend that you telephone Margaret Sieffert, Environmental Engineer, at (312) 353–1151 before visiting the Region 5 office.

FOR FURTHER INFORMATION CONTACT:
Margaret Sieffert, Environmental Engineer, Environmental Protection Agency, Region 5, 77 West Jackson Boulevard (AT–18J), Chicago, Illinois 60604, (312) 353–1151, *sieffert.margaret@epa.gov.*

SUPPLEMENTARY INFORMATION:
Throughout this document whenever ''we,'' ''us,'' or ''our'' is used, we mean EPA. This supplementary information section is arranged as follows:

I. Background

Sections 111(d) and 129 of the Clean Air Act require submittal of State plans to control certain pollutants (designated pollutants) at existing solid waste combustion facilities (designated facilities) whenever standards of performance have been established under section 111(d) for new sources of the same type and EPA has established emission guidelines for such existing sources. Standards of performance for new LMWC units and emission guidelines for all existing LMWC units constructed on or before September 20, 1994, were originally established by EPA on December 15, 1995 (60 FR 65415).

EPA approved Illinois' LMWC State Plan to implement EPA's emission guidelines for existing LMWCs on December 29,1997 at 62 FR 67570 and codified at 40 CFR 62.3350. The only LMWC operating in the State was Robbins Resource Recovery Center (RRRC). On May 10, 2006, EPA promulgated revised LMWC emission guidelines under 40 CFR part 60 subpart Cb, that triggered the need for states to submit revised State Plans to implement the revised emission guidelines for existing sources in the state. However, 40 CFR 62.06 provides that if there are no existing sources of the designated pollutants within a state, the state may submit a letter of certification to that effect, or a negative declaration, in lieu of a plan. The negative declaration exempts the state from the requirements to submit a State Plan for designated pollutants at designated facilities. On February 1, 2012, the Illinois Environmental Protection Agency (IEPA) submitted a negative declaration letter to EPA certifying that the only designated facility in the State Plan, RRRC, ceased operation and is completely shut down, and requested that EPA withdraw the Illinois' State Plan implementing the emission guidelines for LMWCs.

II. Final Action

IEPA has determined that there are now no existing facilities subject to subpart Cb requirements in the State. EPA accepts the State's negative declaration. EPA is approving the State of Illinois' negative declaration and request for withdrawal of its State Plan for LMWCs. Accordingly, EPA is amending part 62 to reflect approval of the IEPA February 1, 2012, negative declaration and request for EPA withdrawal of the LMWC State Plan. However, if an affected Illinois LMWC unit is discovered in the future, all the requirements of the Federal plan (including revisions or amendments), part 62, subpart FFF, will be applicable to the affected unit.

EPA is publishing this approval notice without prior proposal because the Agency views this as a non-controversial action and anticipates no adverse comments. However, in the proposed rules section of this **Federal Register** publication, EPA is publishing a separate document that will serve as the proposal to approve the State's negative declaration and request for withdrawal of Illinois' State Plan for LMWC units in the event adverse comments are filed. This rule will be effective July 30, 2012 without further notice unless we receive relevant adverse written comments by July 2, 2012. If we receive such comments, we will withdraw this action before the effective date by publishing a subsequent document that will withdraw the final action. All public comments received will then be addressed in a subsequent final rule based on the proposed action. EPA will not institute a second comment period. Any parties interested in commenting on this action should do so at this time. If we do not receive any comments, this action will be effective July 30, 2012.

III. Statutory and Executive Order Reviews

A. General Requirements

Under Executive Order 12866 (58 FR 51735, October 4, 1993), this action is not a ''significant regulatory action'' and therefore is not subject to review by the Office of Management and Budget. For this reason, this action is also not subject to Executive Order 13211, ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'' (66 FR 28355, May 22, 2001). This action merely approves state law as meeting Federal requirements and imposes no additional requirements beyond those imposed by state law. Accordingly, the Administrator certifies that this rule will not have a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*). Because this rule approves pre-existing requirements under state law and does not impose any additional enforceable duty beyond that required by state law, it does not contain any unfunded mandate or significantly or uniquely affect small governments, as described in the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4). This rule also does not have tribal implications because it will 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, as specified by Executive Order 13175 (65 FR 67249, November 9, 2000). This action also does not have Federalism implications because it does not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132 (64 FR 43255, August 10, 1999). This action merely approves a state rule implementing a Federal requirement, and does not alter the relationship or the distribution of power and responsibilities established in the Clean Air Act. This rule also is not subject to Executive Order 13045 (62 FR 19885, April 23, 1997), because it approves a state rule implementing a Federal standard.

In reviewing Section 111(d)/129 plan submissions, EPA's role is to approve State choices, provided that they meet the criteria of the Clean Air Act. In this context, in the absence of a prior existing requirement for the State to use voluntary consensus standards (VCS), EPA has no authority to disapprove a Section 111(d)/129 plan submission for failure to use VCS. It would thus be inconsistent with applicable law for EPA, when it reviews a Section 111(d)/129 plan submission, to use VCS in place of a Section 111(d)/129 plan submission that otherwise satisfies the provisions of the Clean Air Act. Thus, the requirements of section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272 note) do not apply. This rule does not impose an information collection burden under the provisions of the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*).

B. Submission to Congress and the Comptroller General

The Congressional Review Act, 5 U.S.C. 801 *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. 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 the rule in the **Federal Register**. This rule is not a ''major rule'' as defined by 5 U.S.C. 804(2).

C. Petitions for Judicial Review

Under Section 307(b)(1) of the Clean Air Act, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by July 30, 2012. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this rule for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action. This action approving Illinois' Section 111(d)/129 negative declaration and request for EPA withdrawal of the LMWC plan approval may not be challenged later in proceedings to enforce its requirements. (See section 307(b)(2)).

List of Subjects in 40 CFR Part 62

Environmental protection, Air pollution control, Administrative practice and procedure, Large municipal waste combustors, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: May 16, 2012.

Susan Hedman,

Regional Administrator, Region 5.

40 CFR part 62 is amended as follows:

PART 62—[AMENDED]

■ 1. The authority citation for part 62 continues to read as follows:

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

Subpart P—Illinois

■ 2. Section 62.3350 is amended by revising the section heading, designating the existing paragraph as (a) and adding paragraph (b) to read as follows:

§ 62.3350 Identification of plan—negative declaration.

* * * * *

(b) On February 1, 2012, the Illinois Environmental Protection Agency submitted a negative declaration that there are no large municipal waste combustors in the State of Illinois subject to part 60, subpart Cb emission guidelines and requested withdrawal of its State Plan for LMWC units approved under paragraph (a) of this section.

■ 3. A new § 62.3351 is added to read as follows:

§ 62.3351 Effective date.

The Federal effective date of the negative declaration and withdrawal of Illinois' State Plan for LMWC units is July 30, 2012.

[FR Doc. 2012–13205 Filed 5–30–12; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 81

[EPA–R09–OAR–2010–0491; FRL–9679–7]

Designation of Areas for Air Quality Planning Purposes; State of Arizona; Pinal County; PM_{10}

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: Pursuant to section 107(d)(3) of the Clean Air Act, the EPA is redesignating from ''unclassifiable'' to ''nonattainment'' an area in western Pinal County, Arizona, for the 1987 national ambient air quality standard for particles with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM_{10}), and therefore also revising the boundaries of the existing ''rest of state'' unclassifiable area. The EPA's establishment of this new PM_{10} nonattainment area, referred to as ''West Pinal,'' is based on numerous recorded violations of the PM_{10} standard at various monitoring sites within the county. With the exception of Indian country and certain Federal lands, the EPA's nonattainment area boundaries generally encompass the land geographically located within Pinal County north of the east-west line defined by the southern line of Township 9 South, Gila and Salt River Baseline and Meridian, and west of the north-south line defined by the eastern line of Range 8 East, except where the boundary extends farther east in the

Florence and Picacho Peak areas. The effect of this action is to establish and delineate a new PM_{10} nonattainment area within Pinal County and thereby to impose certain planning requirements on the State of Arizona to reduce PM_{10} concentrations within this area, including, but not limited to, the requirement to submit, within 18 months of redesignation, a revision to the Arizona state implementation plan that provides for attainment of the PM_{10} standard as expeditiously as practicable but no later than the end of the sixth calendar year after redesignation.

DATES: This rule is effective on July 2, 2012.

ADDRESSES: EPA has established docket number EPA–R09–OAR–2010–0491 for this action. Generally, documents in the docket for this action are available electronically at *http://www.regulations.gov* or in hard copy at EPA Region IX, 75 Hawthorne Street, San Francisco, California. While all documents in the docket are listed at *http://www.regulations.gov,* some information may be publicly available only at the hard copy location (e.g., copyrighted material, large maps, multi-volume reports), and some may not be available in either location (e.g., confidential business information (CBI)). To inspect the hard copy materials, please schedule an appointment during normal business hours with the contact listed in the **FOR FURTHER INFORMATION CONTACT** section.

FOR FURTHER INFORMATION CONTACT:

Ginger Vagenas, EPA Region IX, (415) 972–3964, *vagenas.ginger@epa.gov.*

SUPPLEMENTARY INFORMATION:

Throughout this document, ''we,'' ''us,'' and ''our'' refer to EPA.

Table of Contents

I. Background

On July 1, 1987, the EPA revised the national ambient air quality standards (NAAQS or ''standards'') for particulate matter (52 FR 24634), replacing total suspended particulates as the indicator for particulate matter with a new indicator called PM_{10} that includes only those particles with an aerodynamic diameter less than or equal to a nominal 10 micrometers.[1] In order to attain the NAAQS for 24-hour PM_{10}, an air quality monitor cannot measure levels of PM_{10} greater than 150 micrograms per cubic meter (μg/m³) more than once per year on average over a consecutive three-year period. The rate of expected exceedances indicates whether a monitor attains the air quality standard.

Most of Pinal County, Arizona, including the area that is the subject of today's action, was included in the ''rest of state'' area, which was designated ''unclassifiable'' for PM_{10} by operation of law upon enactment of the 1990 amendments to the Clean Air Act (CAA or ''Act'').[2] See section 107(d)(4)(B)(iii). The PM_{10} designations established by operation of law under the CAA, as amended in 1990, are known as ''initial'' designations. The CAA grants the EPA the authority to change the designation of, or ''redesignate,'' such areas in light of changes in circumstances. More specifically, CAA section 107(d)(3) authorizes the EPA to revise the designation of areas (or portions thereof) on the basis of air quality data, planning and control considerations, or any other air-quality-related considerations that the EPA deems appropriate. Pursuant to CAA section 107(d)(3), the EPA in the past has redesignated certain areas in Arizona to nonattainment for the PM_{10} NAAQS, including the Payson and Bullhead City areas. See 56 FR 16274 (April 22, 1991); and 58 FR 67334 (December 21, 1993).

On October 14, 2009, under CAA section 107(d)(3)(A), the EPA notified the Governor of Arizona and tribal leaders of the four Indian Tribes (whose Indian country is located entirely, or in part, within Pinal County) that the designation for Pinal County, and any nearby areas that may be contributing to the monitored violations in Pinal County, should be revised (''EPA's notification''). Our decision to initiate the redesignation process stemmed from review of 2006–2008 ambient PM_{10} monitoring data from PM_{10} monitoring stations within the county that showed widespread, frequent, and in some instances, severe, violations of the PM_{10} standard.[3]

Pursuant to section 107(d)(3)(B) of the Act, in a letter dated March 23, 2010, the Governor of Arizona responded to the EPA's notification with a recommendation for a partial-county nonattainment area.[4]

The boundaries of the prospective PM_{10} nonattainment area recommended by the Governor of Arizona encompass a portion of central and western Pinal County, and form an area that resembles a backwards ''L.'' [5] See figure 2 of the EPA's Technical Support Document [6] (TSD) for a map of both the State's recommended boundaries as well as the EPA's proposed boundaries. The state-recommended area includes all or most of the cities of Maricopa, Coolidge, Casa Grande, and the Pinal County portion of the town of Queen Creek, as well as the western-most portion of the town of Florence and the northern-most portion of the city of Eloy. The State recommends including an area that at its western-most boundary includes nearly all of the City of Maricopa. The State-recommended southern boundary is defined by a line that coincides approximately with Interstate 8. The area recommended by the State continues to the east for approximately 35 miles where it extends to the north, including portions of Florence and Coolidge, and the Pinal County portion of Queen Creek, and terminates just south of Apache Junction. The State-recommended eastern boundary is defined by the north-south line between Range 8 East and Range 9 East. The northern boundary follows the county line south from the Apache Junction area and then follows the boundary of the Gila River Indian Reservation to close back around to the recommended western boundary. See the Governor's

[1] The 1987 p.m.$_{10}$ standard included a 24-hour (150 micrograms per cubic meter (μg/m³)) and an annual standard (50 μg/m³). In 2006, EPA revoked the annual standard. See 71 FR 61144 (October 17, 2006) and 40 CFR 50.6.

[2] While most of Pinal County was designated ''unclassifiable,'' two PM_{10} planning areas that extend into Pinal County were designated under the CAA, as amended in 1990, as ''nonattainment:'' the Phoenix planning area, which includes the Apache Junction area within Pinal County; and the Hayden/Miami planning area, which includes the northeastern portion of the county. See 56 FR 11101 (March 15, 1991); 56 FR 56694 (November 6, 1991); and 57 FR 56762 (November 30, 1992). In 2007, we approved a redesignation request by the State of Arizona to split the Hayden/Miami PM_{10} nonattainment area into two separate PM_{10} nonattainment areas. See 72 FR 14422 (March 28, 2007). Today's proposed action would not affect these pre-existing PM_{10} nonattainment areas. EPA codifies area designations in 40 CFR part 81. The area designations for the State of Arizona are codified at 40 CFR 81.303.

[3] In a letter dated October 14, 2009, EPA notified the State of Arizona that the PM_{10} designation in Pinal County should be revised. EPA notified the tribal leaders of the Ak-Chin Indian Community, Gila River Indian Community, San Carlos Apache Tribe, and Tohono O'odham Nation by letters dated December 30, 2009.

[4] Letter from Jan Brewer, Governor of Arizona, to Jared Blumenfeld, Regional Administrator, EPA Region IX, dated March 23, 2010.

[5] The Governor expressly recommended excluding Indian country from the nonattainment area. EPA finds this appropriate, given that the State of Arizona is not authorized to administer programs under the CAA in the affected Indian country. The ''backwards L'' shape of the recommended area is partly explained by this exclusion because the recommended area partially surrounds Indian country.

[6] EPA Region 9, ''Pinal County, Arizona, Area Designation for the 1987 24-hour PM_{10} National Ambient Air Quality Standard,'' Technical Support Document, September 21, 2010.

March 23, 2010 letter for the legal description of the State's recommended boundaries by township and range and for an enclosed map illustrating this area.

In a letter dated February 11, 2010, the Tohono O'odham Nation (TON) responded to the EPA's December 30, 2009 letter concerning the PM_{10} designation in Pinal County with a recommendation that the TON land within Pinal County be designated attainment/unclassifiable for PM_{10}. In a letter dated September 2, 2010 the Ak-Chin Indian Community responded to the EPA's December 30, 2009 letter concerning the PM_{10} designation of Pinal County with a recommendation that the Ak-Chin lands be designated attainment/unclassifiable. The Gila River Indian Community and the San Carlos Apache Tribe did not submit recommendations.

II. Proposed Action

On October 1, 2010 (75 FR 60680), pursuant to section 107(d)(3) of the CAA, the EPA proposed to redesignate from ''unclassifiable'' to ''nonattainment'' an area generally covering the western half of Pinal County, Arizona, for the 1987 PM_{10} NAAQS, and to make a corresponding revision to the boundaries of the existing ''rest of state'' unclassifiable area. The EPA's proposed boundaries for the nonattainment area encompassed all of the area recommended by the State of Arizona, but extended farther to the east and south, and to a lesser degree, to the north and west. The EPA's proposed boundaries encompassed all land geographically located within Pinal County west of the north-south line defined by the boundary between Range 10 East and Range 11 East, but excluded TON's main reservation and the Apache Junction portion of the existing Phoenix PM_{10} nonattainment area. See figure 2 of the EPA's TSD for a map showing our proposed boundaries.

As explained in our October 1, 2010 proposed rule (75 FR at 60686), and more fully in the TSD for the proposal, we believe that the State's recommended boundaries would not encompass the full geographic area from which emissions-generating activities contribute to the monitored PM_{10} violations. More specifically, EPA's proposal stated that the Governor's recommended boundaries, which cut through municipalities and contiguous expanses of agricultural fields, excluded sources that have been identified as dominant sources of PM_{10} and that are contributing to elevated levels of PM_{10} at violating monitors. In our October 1, 2010 proposal, EPA stated that its proposed boundaries, described above, would encompass the areas in which PM_{10} violations are being monitored, as well as the areas that contribute to the monitored violations, and that they were thus consistent with the definition of nonattainment areas in CAA section 107(d)(1)(A). Our proposal was based on the EPA's analysis of the factors as set forth in the proposed rule (75 FR at 60682–60686) and in further detail in the TSD for the proposed rule.

With respect to the affected Indian Tribes, for the reasons given in the proposed rule, we proposed to exclude the main TON reservation and the San Carlos Apache Reservation from the PM_{10} nonattainment area boundaries, but we indicated that we were deferring action on the status of certain other tribal lands located within the area, including the tribal lands of the Ak-Chin Indian Community and the Gila River Indian Community, as well as TON's Florence Village and San Lucy Farms, pending consultation with the affected tribes.

Please see our October 1, 2010 proposed rule and our related TSD for more information about our proposed action and the rationale for our proposed boundaries.

III. Public Comment and EPA Responses

Our October 1, 2010 proposed rule provided for a 30-day comment period, and the EPA received 11 comment letters in response to the proposal, including letters from the Arizona Department of Environmental Quality (ADEQ), the Arizona Game and Fish Department, the Pinal County Air Quality Department, the City of Casa Grande, the Central Arizona Irrigation and Drainage District, the Arizona Public Service Company, several agricultural groups, the Sierra Club, and a member of the general public.

None of the commenters disagreed with the need to redesignate a portion of Pinal County nonattainment for the 1987 24-hour PM_{10} NAAQS, and none disagreed with EPA's conclusion that sources outside of Pinal County and in the eastern half of Pinal County, including San Carlos Apache lands, do not contribute to violations in the western portion of the county. In addition, none of the commenters disagreed with EPA's conclusion that the activities occurring on the main Tohono O'odham Nation (TON) reservation do not contribute to these violations. Most commenters, however, suggested that the nonattainment area should be smaller than that proposed by the EPA. Nine commenters supported the Governor's recommended boundary, one commenter supported the EPA's proposed boundary, and one commenter suggested that the boundary should include only developed areas that have a relatively high density of human population.

As discussed in more detail below and in our Response to Comments (RTC) document,[7] the EPA is taking final action today to redesignate from ''unclassifiable'' to ''nonattainment'' an area generally covering the western half of Pinal County, Arizona, for the 1987 PM_{10} NAAQS, and correspondingly, to revise the boundaries of the existing ''rest of state'' unclassifiable area. In our final action, however, based on our consideration of the comments, including the building permit data provided by Pinal County that documents the extent to which the national recession has slowed growth in Pinal County, and after further review of other relevant factors, such as the geographic distribution of sources of PM_{10}, the EPA is modifying the boundaries it had proposed for the nonattainment area. EPA's final action modifies its previously proposed boundaries in such a way as to reduce the size of the nonattainment area (relative to the area the EPA had proposed) by approximately 36 percent (about 735 square miles). This reduction is principally accounted for by establishing the final boundaries for the nonattainment area so as to exclude the Tonto National Forest (including the Superstition Wilderness Area), portions of the Sonoran Desert National Monument (including the Table Top Wilderness Area), the Ironwood Forest National Monument, and certain less-developed areas. EPA's proposal had included these areas within the nonattainment area boundaries.

In the following paragraphs of this section, we summarize our responses to significant comments that we received on our October 1, 2010 proposed rule. Our full responses to all the comments received can be found in the previously-cited RTC document, which is included in the docket for this rulemaking.

Air Quality Data

Comment: Disagreement over the size of the nonattainment area was primarily based on commenters' views that certain areas should be excluded from the nonattainment area because they are not themselves violating the standard, or because they are not ''significantly''

[7] EPA Region 9, ''Response to Comments on the Proposed Action to Redesignate West Pinal County to Nonattainment for the 1987 24-hour PM_{10} National Ambient Air Quality Standard,'' May 2012.

contributing to violations in nearby areas.

Response: CAA section 107(d)(1)(A)(i) defines a nonattainment area to include ''any area that does not meet (or that contributes to ambient air quality in a nearby area that does not meet)'' the NAAQS. Thus, a location is designated nonattainment if its emissions contribute to the air quality in a nearby area that violates the NAAQS, even if that location is not the main cause of violations, and even if it does not contribute to every measured violation. The absence of a violation at a particular monitor does not preclude the possibility of elevated levels of particulate in the vicinity of that monitor or the transport of particulate to a nearby violating area, even if levels do not cause a violation at the monitor itself. A contiguous area can be nonattainment if it is within several miles of a violating monitor and has emissions that travel to that monitor, even if its contribution is not as large as those of locations nearer the monitor.

Exceptional Events

Comment: Two commenters noted that some of the measured exceedances have been flagged as exceptional events [8] and suggested that the EPA should not consider a monitor to be violating if all of the exceedances have been flagged as exceptional events. ADEQ stated that its analysis of the most recent monitoring data indicated that if flagged exceptional events were excluded from the monitoring record, four monitors (Casa Grande, Combs School, Coolidge, and Maricopa) would be attaining the standard.

Response: Based on the most recent certified data (2009–2011), seven monitors in Pinal County are violating the 24-hour PM_{10} standard. EPA regulations do provide that a State may request EPA to exclude data showing exceedances or violations of the national ambient air quality standard that are directly due to an exceptional event from use in determinations, by demonstrating to the EPA's satisfaction that such event caused a specific air pollution concentration at a particular air quality monitoring location. (40 CFR 58.14) However, as indicated in the proposed rule (75 FR at 60684–60685), even if we were to concur and to exclude from use in determining attainment all of the flagged exceedances, a number of monitors would still violate the standard. Moreover, the emissions sources in the vicinities of the non-violating monitors (i.e., presuming exclusion of the flagged exceedances as caused by exceptional events) are those, such as traffic on paved and unpaved roads, cattle operations, agricultural sources, and construction-generated emissions, that we have determined contribute to violations of the standard elsewhere in the County. Thus, EPA action on State flagged exceptional event claims is not a prerequisite to finalizing this redesignation and establishing appropriate boundaries for the new West Pinal PM_{10} nonattainment area.

Geographic Distribution of Emissions Sources

Comment: A number of commenters objected to EPA's proposed boundary because, in their view, sources of PM_{10} emissions leading to monitored violations are located in the western regions of Pinal County, not the east or south [of the Governor's recommended nonattainment area [9]]. They argued that the Governor's recommended boundary included all of the emissions sources that contribute significantly to the PM_{10} violations, plus an adequate buffer to the south and east.

Commenters pointed to differences in activity levels and the degree of urbanization in areas within and outside the Governor's recommended boundary and argued that the State's preliminary emissions inventory showed that sources in the eastern and/or southern regions of the county do not significantly contribute to violations in other regions of the county.

Response: Arizona's preliminary PM_{10} inventory and the 2005 National Emissions Inventory, version 2, along with source apportionment studies, identify the sources that contribute to elevated concentrations of PM_{10}. These sources include on-road emissions, cattle operations, agriculture, and construction. According to ADEQ's technical report, these sources of PM_{10} are located throughout the western portion of Pinal County, including areas to the east and south of the Governor's recommended boundary. See Figures 3–3 and 3–4 of ADEQ's technical report.[10] The EPA's review of meteorological data indicates that emissions from these areas are transported to the violating monitors 35 to 40% of the time. See the wind rose data collected at the Pinal Air Park as illustrated in Figure 10 of the TSD for the proposal and note the absence of topographic barriers as shown in Figure 11 of the TSD.

As stated above, CAA defines a nonattainment area to include a nearby area that contributes to air quality in the area where violations are measured. To identify nearby areas that contribute to the measured violations of PM_{10} in Pinal County, we have used a multi-factor analysis that accounts for, among other factors, emissions data, meteorology, and topography, as described in detail in EPA's TSD for the proposed rule and in the RTC document prepared for this final rule. The use of a multi-factor test in determining which areas contribute to violations in a nearby area was upheld in a case involving designations and nonattainment area boundaries for the $PM_{2.5}$ standard, *Catawba County* v. *EPA,* 571 F.3d 20, 38–40 (D.C. Cir. 2009), and we believe such a test is appropriate in determining the boundaries of an area to be redesignated to nonattainment for the PM_{10} standard. Moreover, the *Catawba County* court rejected arguments that ''contributes,'' for the purposes of interpreting the geographic extent of nonattainment areas under section 107(d)(1)(A), necessarily connotes a significant causal relationship and upheld EPA's interpretation of ''contribute'' to mean ''sufficiently contribute'' and then applying a presumption and multi-factor test precisely to identify those areas that meet the definition. *Id.* In the context of this action, we have not applied any presumption but otherwise have identified the boundaries of the area to be redesignated to nonattainment for the PM_{10} standard to include areas determined to be sufficiently contributing through application of a multi-factor test.

Off-Highway Vehicles

Comment: The Arizona Game and Fish Department argued that because ADEQ's technical report states that off-highway vehicle emissions are relatively low and there were no grid cells over the 20 ton per year threshold, the nonattainment area boundary should not include undeveloped lands where off-highway vehicle recreation occurs.

[8] On March 22, 2007, EPA adopted a final rule, *Treatment of Data Influenced by Exceptional Events,* (EER), to govern the review and handling of certain air quality monitoring data for which the normal planning and regulatory processes are not appropriate. Under the rule, EPA may exclude data from use in determinations of NAAQS exceedances and violations if a state demonstrates that an ''exceptional event'' caused the exceedances. See 72 FR 13560.

[9] Commenters referring to the ''eastern'' and ''southern'' portions of Pinal County appear to be referring to the areas to the east and south of the Governor's recommended nonattainment boundary. In our TSD and in the RTC, EPA's references to the eastern and western portions of Pinal County mean those portions of Pinal County that lie to the east and west of the eastern boundary of *EPA's* proposed nonattainment area.

[10] ADEQ, ''Arizona Air Quality Designations, Technical Support Document, Boundary Recommendation for the Pinal County 24-hour PM_{10} Nonattainment Area,'' March 15, 2010.

Response: Upon consideration of public comments, the EPA has revised our proposed nonattainment area boundary to minimize the inclusion of areas where available information indicates emissions are relatively low. We have established a final nonattainment area that we believe encompasses the areas in which PM_{10} violations are being monitored, as well as the areas that contribute to the monitored violations, consistent with the definition of nonattainment areas in CAA section 107(d)(1)(A). While this might result in the inclusion of some lands where off-highway vehicle recreation occurs, it does not dictate the application of controls on or regulation of emissions generated by such activities. Arizona will be required to develop a plan that demonstrates attainment of the PM_{10} standard, and the relative contribution of various sources and options for control will be considered in that process. That plan will be subject to public review and comment, both at the state level and again when the EPA evaluates the plan for approval or disapproval as a revision to the Arizona state implementation plan (SIP).

Wilderness Areas

Comment: Four commenters objected to the inclusion of the Table Top and Superstition Wilderness areas within the nonattainment area, noting that such areas are generally closed to mechanized equipment and do not include sources that could be contributing to exceedances at the violating monitors. The Arizona Game and Fish Department and ADEQ also argued that, EPA had not adequately justified including these wilderness areas and the Tonto National Forest in the nonattainment area. The Arizona Game and Fish Department requested that the EPA remove these areas and other largely undeveloped, rural areas from the nonattainment boundary.

Response: The EPA agrees that, because the wilderness areas and the Tonto National Forest are generally closed to mechanized equipment and lacking in emissions sources, the areas do not contribute to violations at the monitors elsewhere in Pinal County. As a result, we have finalized boundaries that do not include either of the wilderness areas or any portion of the Tonto National Forest, and we have sought to minimize the inclusion of undeveloped land.

Traffic and Commuting Patterns

Comment: Several commenters believe that EPA's inclusion in the proposed nonattainment area of lands in the western half of Pinal County that lie to the east and south of the Governor's recommended boundary is not justified given the traffic patterns and concentration of roads in this area. Commenters stated that the largest category of PM_{10} emissions in Pinal County is on-road sources, and noted that current traffic and commuter-related emissions are located primarily in the western portions of the county in the more populated regions of Casa Grande and Maricopa. Another commenter asserted that the number of commuters traveling between Pima and Pinal Counties is significantly less than the number traveling between Maricopa and Pinal counties. One commenter contended that the area south of Interstate 8 does not have any roads that lead to major urban centers, except for Interstate 10, and contended that proximity to Interstate 10 does not cause the Pinal Air Park or Eloy monitors to violate.

Response: Although the EPA and ADEQ inventories differed with respect to the quantity of emissions generated by on-road sources (traveling on paved and unpaved roads), EPA and ADEQ agree that this is the largest category of PM_{10} emissions in Pinal County. EPA TSD Figure 8 and ADEQ technical report Figure 3–5 illustrate the distribution of commuter traffic and emissions generated by traffic on paved roads. Taken together with the overall distribution of on-road emissions shown in ADEQ's technical report (Figure 3–4), it is evident that on-road traffic (including paved and unpaved roads) is a significant source of emissions in the western half of Pinal County, including areas to the south and east of the Governor's recommended boundary.

The EPA believes that the distribution of emissions from on-road traffic requires extending Arizona's recommended boundary; however, upon further review, we concluded that the comments submitted and further review of available data provide a persuasive case for modifying EPA's proposed boundary. For the final nonattainment area boundaries, we reduced emphasis on the growth and commuting patterns and increased the weight given to emissions- and land-use-related data and thus are not including the southern-most portion of Pinal County, the Table Top and Superstition Wilderness areas, and the largely undisturbed desert areas east of Township 8 East, except where the boundary extends farther to the east to include the Florence area and the Picacho Peak area.

Growth Rates and Patterns

Comment: Several commenters argued that growth forecasts made prior to the economic downturn are no longer reliable given current economic conditions, and that future growth is uncertain. Others noted that actual growth in the area south of the Governor's recommended boundary has been modest, and that this area is unlikely to become a major employment center. These commenters questioned the view EPA expressed in its proposal that future employment and population growth in Pinal County justify including the southern portion of the county in the nonattainment area.

Response: In our final action, after considering the comments submitted on our proposal, EPA has reduced the size of the nonattainment area, relative to what was proposed. As noted above in our response to the previous comment, the final nonattainment boundaries do not include the southern-most portion of Pinal County, the Table Top and Superstition Wilderness areas, and the largely undisturbed desert areas east of Township 8 East, except where the boundary extends farther to the east to include the Florence area and the Picacho Peak area. We are persuaded to shrink the boundary in part based on the building permit data provided by Pinal County that documents the extent to which the national recession has slowed growth generally in Pinal County, and particularly in the Interstate 8 and Interstate 10 corridors. We agree that the recession and the number of homes already in foreclosure will likely delay significant growth in the corridors beyond the five-year horizon for reaching attainment of the standard. The Pinal Air Park monitor, located southwest of Interstate 10 near the southern border of Pinal County, is not included within the final boundary. However, as EPA proposed, the Eloy monitor, is part of the final nonattainment area, because EPA continues to believe that the sources in the Eloy area contribute to violations of the PM_{10} NAAQS farther north.

Meteorology and Transport

Comment: ADEQ and Pinal County Air Quality (PCAQ) asserted that the meteorological data do not support the EPA's inclusion of the southeastern portion of the nonattainment area. In brief, the comments are: (1) The southeast should not be included, since the Eloy monitor there is not violating; (2) the meteorological data relied on by the EPA do not substantiate transport from the southeast; (3) meteorological data show the cause of PM_{10} violations is local, not transport from the southeast; and (4) the limited data showing instances where measured exceedances have coincided with southeast winds does not justify including the southeast portion.

Response: EPA has included areas to the southeast of the State's recommended boundary, including those near the Eloy monitor, because of the contribution of southeast emissions to violations recorded at the Casa Grande and Pinal County Housing monitors. The EPA does not agree with the commenters' implicit assumption that the southeast portion must be the sole or main cause of violations in order for it to be included in the nonattainment area. While emissions from the southeast may not cause a violation at Eloy, they still contribute to violations farther northwest.

Our conclusion that the area southeast of the State's boundary in and around Eloy contributes to the violations farther northwest is based on (1) emissions inventory data (see table 3 of the TSD for the proposed rule) that shows that PM_{10} emissions from traffic on paved and unpaved roads, and agricultural and agricultural activities account for most of the overall inventory in Pinal County; (2) maps illustrating the locations of agricultural uses and paved and unpaved roads (see figure 4 and figure 9 of the TSD, respectively) and showing a concentration of such uses and roads in and around Eloy; (3) a map illustrating the distribution of overall PM_{10} emissions in the county (see figure 5 of the TSD) and showing similar rates of emissions generated in and around Eloy as the area where violations of the standard occur; meteorological data showing a strong component of winds from the southeast (see figure 10 of the TSD); and the absence of significant topographical barriers to transport from the area in and around Eloy to the area where violations occur (see figure 11 of the TSD). This contribution to violations warrants inclusion of this portion of the county in the nonattainment area.

As discussed in EPA's proposal and in the Meteorology section of the TSD, we agree that it would be desirable to have additional meteorological data available. Nonetheless, EPA believes that there are sufficient meteorological data from the AZMET (Arizona Meteorological Network) stations within and around the proposed area to show that flow from the southeast toward the violating monitors occurs often. The EPA believes that this pattern exists even during the exceedance days discounted by ADEQ and PCAQ.[11] The available meteorological data, along with the topography and the geographic distribution of sources of PM_{10} emissions, provide evidence that emissions sources in the southeast contribute to NAAQS violations. EPA has concluded that the nonattainment area boundary should lie further to the southeast than the Governor's recommended boundary, though we have reduced the extent relative to the area we had proposed to include.

Comment: Both ADEQ and PCAQ examined HYSPLIT[12] back-trajectories for several high-wind exceedance days, along with hourly concentrations and wind data. From the abrupt changes in wind direction and increases in wind speed that often coincided with large increases in PM_{10} concentrations, they concluded that the PM_{10} is due to near-field impacts rather than to long-range transport.

Response: While the analyses performed by ADEQ and Pinal County provide useful information for evaluating the PM_{10} exceedances, as discussed above, establishing nonattainment area boundaries requires us to take into account more than the sole or main cause of an exceedance. Even if the commenters are correct that on certain occasions ''wind-transport from the southeast is not a dominant contributing factor'' (ADEQ comments, p.4) and that the data ''suggest a typical monsoon storm where local weather contributed to local impacts'' (Pinal County comments, p.3), EPA remains convinced by the available evidence that transported emissions from the southeast nonattainment area nevertheless do contribute to exceedances. As discussed in more detail in the TSD for the EPA's proposal and in the RTC document, the EPA believes that the meteorological data provide evidence for such a contribution. Other factors, including the geographic distribution of sources of emissions and the topography of Pinal County also reinforce EPA's determination to include this portion in the nonattainment area.

IV. Final Action

For the reasons provided in the proposed rule and TSD, insofar as not modified here, the Response to Comments document, and this final rule, the EPA is taking final action pursuant to section 107(d)(3) of the Clean Air Act to redesignate an area in western Pinal County, Arizona from ''unclassifiable'' to ''nonattainment'' for the 1987 24-hour PM_{10} standard and is therefore also revising the boundaries of the existing ''rest of state'' unclassifiable area. EPA's establishment of this new PM_{10} nonattainment area, referred to as ''West Pinal,'' is based on numerous recorded violations of the PM_{10} standard at various monitoring sites within the western portion of the county. With the exception of Indian country and certain Federal lands, the EPA's nonattainment area boundaries generally encompass the land geographically located within Pinal County north of the east-west line defined by the southern line of Township 9 South, Gila and Salt River Baseline and Meridian, and west of the north-south line defined by the eastern line of Range 8 East, except where the boundary extends farther east in the Florence and Picacho Peak areas.[13] In taking this action, the EPA concludes that the State's recommended boundaries do not encompass the full geographic area from which emissions-generating activities contribute to the monitored PM_{10} violations. See figure 1 in the RTC document for a map that compares the State's recommended boundaries to the EPA's final boundaries.

For this final action, we reduced the size of the nonattainment area relative to the area for which we proposed redesignation and believe that the final boundaries more closely align the nonattainment area boundaries with the areas in which PM_{10} violations are being monitored, as well as the areas that contribute to the monitored violations. Our conclusion is based on our analysis of the factors as set forth in the proposed rule and related TSD, and RTC document, with particular weight being given to the locations of those sources, including vehicle travel over paved and unpaved roads, and agricultural and construction activities, that comprise most of the overall PM_{10} inventory, the frequent occurrence of southeast winds, and the absence of topographical barriers.

We are continuing to defer our decision regarding redesignation of the Ak-Chin and Gila River Indian Community lands, as well as TON's Florence Village and San Lucy Farms, pending consideration of issues unique

[11] In their transport analyses, PCAQ and ADEQ focused on days with the wind trajectory's ending hour oriented from the southeast, but this does not consider other hours during the day that may have had flow from the southeast.

[12] The HYSPLIT (HYbrid Single-Particle Lagrangian Integrated Trajectory) model is used to compute simple air parcel trajectories, dispersion characteristics, and deposition simulations.

[13] Townships to the east of the north-south line defined by the eastern line of Range 8 East that are included in the West Pinal PM_{10} nonattainment area are: T3S, R9E; T4S, R9E; T4S, R10E; T5S, R9E; and T5S, R10E.

to tribal lands, completion of formal consultation with the tribal governments, and (in the case of the Gila River Indian Community) further review of air quality monitoring data including an evaluation of exceptional event claims. The existing Phoenix PM_{10} nonattainment area (including the Apache Junction portion of western Pinal County) is unaffected by this action.

Areas redesignated as nonattainment are subject to the applicable requirements of part D, title I of the Act and will be classified as moderate by operation of law (see section 188(a) of the Act). Within 18 months of the effective date of this redesignation action, the State of Arizona must submit to the EPA an implementation plan for the area containing, among other things, the following requirements: (1) Provisions to assure that reasonably available control measures (including reasonably available control technology) are implemented within 4 years of the redesignation; (2) a permit program meeting the requirements of section 173 governing the construction and operation of new and modified major stationary sources of PM_{10}; (3) quantitative milestones which are to be achieved every 3 years until the area is redesignated attainment and which demonstrates reasonable further progress, as defined in section 171(1), toward timely attainment; and (4) either a demonstration (including air quality modeling) that the plan will provide for attainment of the PM_{10} NAAQS as expeditiously as practicable, but no later than the end of the sixth calendar year after the area's designation as nonattainment, or a demonstration that attainment by such date is impracticable (see, e.g., section 188(c), 189(a), 189(c), and 172(c) of the Act). We have issued detailed guidance on the statutory requirements applicable to moderate PM_{10} nonattainment areas [see 57 FR 13498 (April 16, 1992), and 57 FR 18070 (April 28, 1992)].

The State will also be required to submit contingency measures (for the new PM_{10} nonattainment area), pursuant to section 172(c)(9) of the Act, which are to take effect without further action by the State or the EPA, upon a determination by the EPA that an area has failed to make reasonable further progress or attain the PM_{10} NAAQS by the applicable attainment date (see 57 FR 13510–13512, 13543–13544). Pursuant to section 172(b) of the Act, the EPA is establishing a deadline for submission of contingency measures to coincide with the submittal date requirement for the other SIP elements discussed above, i.e., 18 months after the effective date of redesignation. Lastly, the new PM_{10} nonattainment area will be subject to the EPA's general and transportation conformity regulations (40 CFR part 93, subparts A and B) one year from the effective date of redesignation. See section 176(c)(6) of the Act.[14]

Specifically, this section of the CAA provides areas, that for the first time are designated nonattainment for a given air quality standard, with a one-year grace period before conformity applies with respect to that standard. Because this is the first time that this portion of Pinal County is being designated nonattainment for the PM_{10} NAAQS, it will have a one-year grace period before conformity applies for the PM_{10} NAAQS.[15]

The new West Pinal PM_{10} nonattainment area would be considered to be a ''donut area'' because portions of the area in Queen Creek and Apache Junction are within the area covered by a metropolitan planning organization (MPO), the Maricopa Association Governments (MAG) and a portion lies outside of MAG's boundaries. For the purposes of transportation conformity, a donut area is the geographic area outside a metropolitan planning area boundary, but inside the boundary of a designated nonattainment/maintenance area. The transportation conformity requirements for donut areas are generally the same as those for metropolitan areas. However, the MPO would include any projects occurring in the donut area in its regional emissions analysis of the metropolitan transportation plan and Transportation Improvement Program (TIP). Therefore, the one-year grace period applies to donut areas in much the same way that it applies to metropolitan areas. That is, within one year of the effective date of an area's designation, a donut area's projects must be included in the MPO's conformity determination for the metropolitan plan and TIP for those projects to be funded or approved. If, at the conclusion of the one-year grace period, the donut area's projects have not been included in an MPO's conformity determination, the entire nonattainment area's conformity would lapse.[16]

V. Statutory and Executive Order Reviews

A. Executive Order 12866, Regulatory Planning and Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), the EPA has determined that redesignation to nonattainment, as well as the establishment of SIP submittal schedules, would result in none of the effects identified in Executive Order 12866, section 3(f). Under section 107(d)(3) of the Act, redesignations to nonattainment are based upon air quality considerations. The redesignation, based upon air quality data showing that West Pinal is not attaining the PM_{10} standard and upon other air-quality-related considerations, does not, in and of itself, impose any new requirements on any sectors of the economy. Similarly, the establishment of new SIP submittal schedules would merely establish the dates by which SIPs must be submitted, and would not adversely affect entities.

B. Paperwork Reduction Act

This action does not impose an information collection burden under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* Burden is defined at 5 CFR 1320.3(b).

C. Regulatory Flexibility Act

Under the Regulatory Flexibility Act (RFA), 5 U.S.C. 601 *et. seq.,* a redesignation to nonattainment under section 107(d)(3), and the establishment of a SIP submittal schedule for a redesignated area, do not, in and of themselves, directly impose any new requirements on small entities. See *Mid-Tex Electric Cooperative, Inc.* v. *FERC,* 773 F.2d 327 (D.C. Cir. 1985) (agency's certification need only consider the rule's impact on entities subject to the

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[14] The proposed rule mistakenly stated that any new PM_{10} nonattainment area would be subject to the EPA's general and transportation conformity regulations upon the effective date of redesignation. See 75 FR at 60688. However, CAA section 176(c)(6) provides a one-year grace period for newly designated (in this case, newly redesignated) nonattainment areas, i.e., for the pollutant for which the area is newly designated (or redesignated) nonattainment. See also, 40 CFR 93.102(d) in EPA's transportation conformity regulation and 40 CFR 93.153(k) in the EPA's general conformity regulation.

[15] For more information on how the one-year grace period applies for transportation conformity purposes, please see the proposed and final rulemaking entitled, ''Transportation Conformity Rule Amendments: Minor Revision of 18-Month Requirement for Initial SIP Submissions and Addition of Grace Period for Newly Designated Nonattainment Areas,'' published October 5, 2001 (66 FR 50954); and August 6, 2002 (67 FR 50808), respectively. (The proposed and final rule can be found on EPA's transportation conformity Web site: *http://www.epa.gov/otaq/stateresources/transconf/conf-regs-c.htm*).

[16] For more information on transportation conformity requirements in donut areas refer to Conformity Implementation in Multi-jurisdictional Nonattainment and Maintenance Areas for Existing and New Air Quality Standards. In particular refer to question 4 in Part 1 and Part 2 of the guidance. The document is available at: *http://www.epa.gov/otaq/stateresources/transconf/policy/420b04012.pdf.*

requirements of the rule). Instead, this rulemaking simply makes a factual determination and establishes a schedule to require the State to submit SIP revisions, and does not directly regulate any entities. Therefore, pursuant to 5 U.S.C. 605(b), the EPA certifies that today's action does not have a significant impact on a substantial number of small entities within the meaning of those terms for RFA purposes.

D. Unfunded Mandates Reform Act

Under Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, the EPA has concluded that this rule is not likely to result in the promulgation of any Federal mandate that may result in expenditures of $100 million or more for State, local or tribal governments in the aggregate, or for the private sector, in any one year. It is questionable whether a redesignation would constitute a federal mandate in any case. The obligation for the state to revise its State Implementation Plan that arises out of a redesignation is not legally enforceable and at most is a condition for continued receipt of federal highway funds. Therefore, it does not appear that such an action creates any enforceable duty within the meaning of section 421(5)(a)(i) of UMRA (2 U.S.C. 658(5)(a)(i)), and if it does the duty would appear to fall within the exception for a condition of Federal assistance under section 421(5)(a)(i)(I) of UMRA (2 U.S.C. 658(5)(a)(i)(I).

Even if a redesignation were considered a Federal mandate, the anticipated costs resulting from the mandate would not exceed $100 million to either the private sector or state, local and tribal governments. Redesignation of an area to nonattainment does not, in itself, impose any mandates or costs on the private sector, and thus, there is no private sector mandate within the meaning of section 421(7) of UMRA (2 U.S.C. 658(7)). The only cost resulting from the redesignation itself is the cost to the State of Arizona of developing, adopting, and submitting any necessary SIP revision. Because that cost will not exceed $100 million, this action (if it is a federal mandate at all) is not subject to the requirements of sections 202 and 205 of UMRA (2 U.S.C. 1532 and 1535). The EPA has also determined that this action would not result in regulatory requirements that might significantly or uniquely affect small governments because only the State would take any action as result of today's rule, and thus the requirements of section 203 (2 U.S.C. 1533) do not apply.

E. Executive Order 13132, Federalism

Executive Order 13132 requires the 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.'' This rule will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132, because it merely redesignates an area for Clean Air Act planning purposes and does not alter the relationship or the distribution of power and responsibilities established in the Clean Air Act. Thus, the requirements of section 6 of the Executive Order do not apply to this rule.

F. Executive Order 13175, Coordination With Indian Tribal Governments

Executive Order 13175, entitled ''Consultation and Coordination with Indian Tribal Governments'' (65 FR 67249, November 9, 2000), requires the 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 area redesignated in today's action does not include Indian country, and the EPA is deferring action on the Indian country that lies within or adjacent to the newly redesignated area, including the Ak-Chin Indian Reservation, the Pinal County portion of the Gila River Indian Reservation, and TON's Florence Village and San Lucy Farms. In formulating its further action on these areas, the EPA has been communicating with and plans to continue to consult with representatives of the Tribes, as provided in Executive Order 13175. Accordingly, the EPA has addressed Executive Order 13175 to the extent that it applies to this action.

G. Executive Order 13045, Protection of Children From Environmental Health Risks and Safety Risks

This rule is not subject to Executive Order 13045 (''Protection of Children from Environmental Health Risks'') (62 FR 19885, April 23, 1997), because it is not an economically significant regulatory action based on health or safety risks.

H. Executive Order 13211, Actions That Significantly Affect Energy Supply, Distribution, or Use

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) because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act

Section 12 of the National Technology Transfer and Advancement Act (NTTAA) of 1995 requires Federal agencies to evaluate existing technical standards when developing a new regulation. The EPA believes that the requirements of NTTAA are inapplicable to this action because they would be inconsistent with the Clean Air Act.

J. Executive Order 12898, Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Today's action redesignates an area to nonattainment for an ambient air quality standard. It will not have disproportionately high and adverse effects on any communities in the area, including minority and low-income communities.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. section 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. The 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 the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a ''major rule'' as defined by 5 U.S.C. section 804(2).

L. Petitions for Judicial Review

Under section 307(b)(1) of the Clean Air Act, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by July 30, 2012. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this rule for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action. This action may not be challenged later in proceedings to enforce its requirements (see section 307(b)(2)).

List of Subjects in 40 CFR Part 81

Environmental protection, Air pollution control, Intergovernmental relations, National parks, Particulate Matter, Wilderness areas.

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

Dated: May 22, 2012.

Jared Blumenfeld,

Regional Administrator, Region IX.

Part 81, chapter I, title 40 of the Code of Federal Regulations is amended as follows:

PART 81—[AMENDED]

■ 1. The authority citation for part 81 continues to read as follows:

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

Subpart C—Section 107 Attainment Status Designations

■ 2. In § 81.303, the ''Arizona–PM–10'' table is amended by adding a new entry for ''Pinal County'' after the entry for ''Mohave County (part)'' and before the entry for ''Rest of State'' to read as set forth below.

§ 81.303 Arizona.

* * * * *

ARIZONA–PM–10

Designated Area	Designation		Classification	
	Date	Type	Date	Type
* * * * * * *				
Pinal County (part)				
West Pinal	7/2/12	Nonattainment	7/2/12	Moderate.
1. Commencing at a point which is the intersection of the western line of Range 2 East, Gila and Salt River Baseline and Meridian, and the northern line of Township 4 South, which is the point of beginning:				
2. Thence, proceed easterly along the northern line of Township 4 South to a point where the northern line of Township 4 South intersects the western line of Range 7 East;				
3. Thence, northerly along the western line of Range 7 East to a point where the western line of Range 7 East intersects the northern line of Township 3 South;				
4. Thence, easterly along the northern line of Township 3 South to a point where the northern line of Township 3 South intersects the western line of Range 8 East;				
5. Thence, northerly along the western line of Range 8 East to a point where the western line of Range 8 East intersects the northern line of Township 1 South;				
6. Thence, easterly along the northern line of Township 1 South to a point where the northern line of Township 1 South intersects the eastern line of Range 8 East;				
7. Thence southerly along the eastern line of Range 8 East to a point where the eastern line of Range 8 East intersects the Northern line of Township 3 South;				
8. Thence easterly along the northern line of Township 3 South to a point where the northern line of Township 3 South intersects the eastern line of Range 9 East;				
9. Thence southerly along the eastern line of Range 9 east to a point where the eastern line of Range 9 East intersects the northern line of Township 4 South;				
10. Thence easterly along the northern line of Township 4 South to a point where the northern line of Township 4 South intersects the eastern line of Range 10 East;				
11. Thence southerly along the eastern line of Range 10 East to a point where the eastern line of Range 10 East intersects the southern line of Township 5 South;				
12. Thence westerly along the southern line of Township 5 South to a point where the southern line of Township 5 South intersects the eastern line of Range 8 East;				
13. Thence southerly along the eastern line of Range 8 East to a point where the eastern line of Range 8 East intersects the northern line of Township 8 South;				
14. Thence easterly along the northern line of Township 8 South to a point where the northern line of Township 8 South intersects the eastern line of Range 9 East;				
15. Thence southerly along the eastern line of Range 9 east to a point where the eastern line of Range 9 East intersects the northern line of Township 9 South;				
16. Thence easterly along the northern line of Township 9 South to a point where the northern line of Township 9 South intersects the eastern line of Range 10 East;				
17. Thence southerly along the eastern line of Range 10 East to a point where the eastern line of Range 10 East intersects the southern line of Township 9 South;				

ARIZONA–PM–10—Continued

Designated Area	Designation		Classification	
	Date	Type	Date	Type
18. Thence westerly along the southern line of Township 9 South to a point where the southern line of Township 9 South intersects the western line of Range 7 East;				
19. Thence northerly along the western line of Range 7 East to a point where the western line of Range 7 East intersects the southern line of Township 8 South;				
20. Thence westerly along the southern line of Township 8 South to a point where the southern line of Township 8 South intersects the western line of Range 6 East;				
21. Thence northerly along the western line of Range 6 East to a point where the western line of Range 6 East intersects the southern line of Township 7 South;				
22. Thence, westerly along the southern line of Township 7 South to a point where the southern line of Township 7 South intersects the quarter section line common to the southwestern southwest quarter section and the southeastern southwest quarter section of section 34, Range 3 East and Township 7 South;				
23. Thence, northerly along the along the quarter section line common to the southwestern southwest quarter section and the southeastern southwest quarter section of sections 34, 27, 22, and 15, Range 3 East and Township 7 South, to a point where the quarter section line common to the southwestern southwest quarter section and the southeastern southwest quarter section of sections 34, 27, 22, and 15, Range 3 East and Township 7 South, intersects the northern line of section 15, Range 3 East and Township 7 South;				
24. Thence, westerly along the northern line of sections 15, 16, 17, and 18, Range 3 East and Township 7 South, and the northern line of sections 13, 14, 15, 16, 17, and 18, Range 2 East and Township 7 South, to a point where the northern line of sections 15, 16, 17, and 18, Range 3 East and Township 7 South, and the northern line of sections 13, 14, 15, 16, 17, and 18, Range 2 East and Township 7 South, intersect the western line of Range 2 East, which is the common boundary between Maricopa and Pinal Counties, as described in Arizona Revised Statutes sections 11–109 and 11–113;				
25. Thence, northerly along the western line of Range 2 East to the point of beginning which is the point where the western line of Range 2 East intersects the northern line of Township 4 South;				
26. Except that portion of the area defined by paragraphs 1 through 25 above that lies within the Ak-Chin Indian Reservation, Gila River Indian Reservation, and the Tohono O'odham Nation's Florence Village and San Lucy Farms.				

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[FR Doc. 2012–13185 Filed 5–30–12; 8:45 am]

BILLING CODE 6560–50–P

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Parts 22 and 90

[DA 12–643]

Wireless Telecommunications Bureau and Public Safety and Homeland Security Bureau Suspend Acceptance and Processing of Certain Applications for 470–512 MHz Spectrum

AGENCY: Federal Communications Commission.

ACTION: Final rule; limited suspension of specific applications.

SUMMARY: In this document, the Federal Communications Commission (Commission) announce a limited suspension of the acceptance and processing of certain applications for certain services operating in the 470–512 MHz (T–Band) spectrum band in order to maintain a stable spectral landscape while the Commission determines how to implement recent spectrum legislation contained in the Middle Class Tax Relief and Job Creation Act of 2012. The suspension applies only to applications for new or expanded use of T–Band frequencies.

DATES: This suspension is effective May 31, 2012. It has been enforced with actual notice since April 26, 2012.

ADDRESSES: Federal Communications Commission, 445 12th St. SW., Washington, DC 20554.

FOR FURTHER INFORMATION CONTACT: For additional information or questions, please contact Mr. Keith Harper of the Wireless Telecommunications Bureau, (202) 418–2759, *Keith.Harper@fcc.gov,* regarding Part 22 applications; Mr. Terry Fishel of the Wireless Telecommunications Bureau, (717) 338–2602, *Terry.Fishel@fcc.gov,* regarding Part 90 Industrial/Business Pool applications; or Mr. Tracy Simmons of the Public Safety and Homeland Security Bureau, (717) 338–2657, *Tracy.Simmons@fcc.gov,* regarding Part 90 Public Safety Pool applications.

SUPPLEMENTARY INFORMATION: This is a summary of the Commission's *Public Notice,* (''PN'') in DA 12–643, which was released on April 26, 2012. The full text of this document available for public inspection and copying during business hours in the FCC Reference Information Center, Portals II, 445 12th St., SW., Room CY–A257, Washington, DC, 20554 or by downloading the text from the Commission's Web site at *http://www.fcc.gov/.* The complete text also may be purchased from the Commission's duplicating contractor, Best Copy and Printing, Inc., Portals II, 445 12th Street, Suite CY–B402, Washington, DC 20554. Alternative formats are available for people with disabilities (Braille, large print, electronic files, audio format), by sending an email to <*FCC504@fcc.gov*> or calling the Consumer and Government Affairs Bureau at (202) 418–0530 (voice), (202) 418–0432 (TTY).

Synopsis of the Public Notice

On April 26, 2012, the Wireless Telecommunications Bureau and Public Safety and Homeland Security Bureau released a *Public Notice* which suspended the acceptance and processing of certain applications for Part 22 and 90 services operating in the 470–512 MHz spectrum band (T–Band). The suspension will serve to stabilize the spectral environment while the Commission considers issues surrounding future use of the T–Band, solicits input from interested parties, and determines how best to implement recent spectrum legislation contained in the Middle Class Tax Relief and Job Creation Act of 2012.[1]

The filing and processing suspension applies only to applications for new or expanded use of T–Band frequencies for the following radio services in the 470–512 MHz band:

Part 22 Public Mobile Services: Paging and Radiotelephone (radio service code CD), Offshore Radiotelephone (radio service code CO)

Part 90 Industrial/Business Pool: Industrial/Business Pool—Conventional (radio service code IG), Industrial/Business Pool—Commercial, Conventional (radio service code IK), Industrial/Business Pool—Trunked (radio service code YG), Industrial/Business Pool—Commercial, Trunked (radio service code YK)

Part 90 Public Safety Pool: Public Safety Pool—Conventional (radio service code PW), Public Safety Pool—Trunked (radio service code YW).

As such, effective immediately and until further notice, the Bureaus will not accept or process (1) applications for new licenses; (2) applications that seek to modify existing licenses by adding or changing frequencies or locations; (3) applications that seek to modify existing licenses by changing technical parameters in a manner that expands the station's spectral or geographic footprint, such as, but not limited to, increases in bandwidth, power level, antenna height, or area of operation; and (4) any other application that could increase the degree to which the 470–512 MHz band currently is licensed. We clarify that affected applications that are now pending will not be further processed until the Commission decides how to implement the Act, except that defective applications and applications in return status that are not timely resubmitted will be dismissed.

The decision to impose this suspension is procedural in nature, and therefore is not subject to the notice, comment, and effective date requirements of the Administrative Procedure Act.[2] Moreover, there was good cause for not delaying the effect of the suspension until after publication in the **Federal Register**. Such a delay would have been impractical, unnecessary, and contrary to the public interest because it would undercut the purposes of the suspension.[3]

Procedural Matters

1. Paperwork Reduction Act Analysis

This document does not contain proposed information collection(s) subject to the Paperwork Reduction Act of 1995 (PRA), Public Law 104–13. In addition, therefore, it does not contain any new or modified ''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).

2. Congressional Review Act

The Commission's Consumer and Governmental Affairs Bureau, Reference Information Center, SHALL SEND a copy of this *Public Notice* 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).

Federal Communications Commission.

Scot Stone,

Deputy Chief, Mobility Division, Wireless Telecommunications Bureau.

[FR Doc. 2012–12953 Filed 5–30–12; 8:45 am]

BILLING CODE 6712–01–P

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Part 73

[MB Docket No. 09–52; FCC 11–190]

Policies To Promote Rural Radio Service and To Streamline Allotment and Assignment Procedures

AGENCY: Federal Communications Commission.

ACTION: Final rule; announcement of effective date.

SUMMARY: In this document, the Commission announces that the Office of Management and Budget (OMB) has approved, for a period of three years, the information collection requirements and form revisions associated with the Commission's rules contained in the Third Report and Order, FCC 11–190, pertaining to the policies to promote rural radio service and to streamline allotment and assignment procedures. This notice is consistent with the Third Report and Order, which stated that the Commission would publish a document

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[1] Public Law 112–96, 126 Stat. 156 (2012). Section 6103 of the Act provides that, not later than nine years after the date of enactment, the Commission shall ''reallocate the spectrum in the 470–512 MHz band * * * currently used by public safety eligibles * * *.'' *Id.* at 6103(a). The Act instructs the Commission to ''begin a system of competitive bidding under section 309(j) of the Communications Act of 1934 (47 U.S.C. 309(j)) to grant new initial licenses for the use of the spectrum.'' *Id.* It also provides that ''relocation of public safety entities from the T–Band Spectrum'' shall be completed not later than two years after completion of the system of competitive bidding. *Id.* at 6103(b) and (c).

[2] *See* 5 U.S.C. 553(b)(A), (d); *see also, e.g., Neighborhood TV Co. v. FCC,* 742 F.2d 629, 637–38 (D.C. Cir. 1984) (holding that the Commission's filing freeze is a procedural rule not subject to the notice and comment requirements of the Administrative Procedure Act); *Buckeye Cablevision, Inc.* v. *United States,* 438 F.2d 948, 952–53 (6th Cir. 1971).

[3] *See* 5 U.S.C. 553(b)(B), (d)(3).

in the **Federal Register** announcing the effective date of these rules and form changes.

DATES: 47 CFR 73.3573 and FCC Form 301, published at 77 FR 2916, January 20, 2012, are effective July 2, 2012.

FOR FURTHER INFORMATION CONTACT: Cathy Williams on (202) 418–2918 or via email to: *Cathy.Williams@fcc.gov.*

SUPPLEMENTARY INFORMATION: This document announces that, on April 27, 2012, OMB approved, for a period of three years, the information collection requirements contained in the Commission's Third Report and Order, FCC 11–190, published at 77 FR 2916, January 20, 2012. The OMB Control Number is 3060–0027. The Commission publishes this notice as an announcement of the effective date of the rule section and form revisions.

Synopsis

As required by the Paperwork Reduction Act of 1995 (44 U.S.C. 3507), the FCC is notifying the public that it received OMB approval on April 27, 2012, for the information collection requirements contained in the Commission's rule at 47 CFR 73.3573 and form revisions to FCC Form 301.

Under 5 CFR part 1320, an agency may not conduct or sponsor a collection of information unless it displays a current, valid OMB 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 current, valid OMB Control Number. The OMB Control Number is 3060–0027.

The foregoing notice is required by the Paperwork Reduction Act of 1995, Pub. L. 104–13, October 1, 1995, and 44 U.S.C. 3507.

The total annual reporting burdens and costs for the respondents are as follows:

OMB Control Number: 3060–0027.

Title: Application for Construction Permit for Commercial Broadcast Station, FCC Form 301.

Form Number: FCC Form 301.

OMB Approval Date: April 27, 2012.

OMB Expiration Date: April 30, 2015.

Type of Review: Revision of a currently approved collection.

Respondents: Business and other for-profit entities; Not for profit entities; State, local or Tribal governments.

Number of Respondents and Responses: 4,604 respondents and 8,040 responses.

Estimated Time per Response: 1–6.25 hours.

Frequency of Response: On occasion reporting requirement; Third party disclosure requirement.

Total Annual Burden: 20,497 hours.

Total Annual Costs: $90,659,382.

Obligation to Respond: Required to obtain or retain benefits. The statutory authority for this collection of information is contained in Sections 154(i), 303 and 308 of the Communications Act of 1934, as amended.

Nature and Extent of Confidentiality: There is no need for confidentiality with this collection of information.

Privacy Impact Assessment(s): No impact(s).

Needs and Uses: On January 28, 2010, the Commission adopted a First Report and Order and Further Notice of Proposed Rulemaking (''First R&O'') in MB Docket No. 09–52, FCC 10–24. To enhance the ability of federally recognized Native American Tribes to provide vital radio services to their citizens on Tribal lands, in the First R&O the Commission established a Tribal Priority for use in its radio licensing procedures. On March 3, 2011, the Commission adopted a Second Report and Order (''Second R&O''), First Order on Reconsideration, and Second Further Notice of Proposed Rule Making in MB Docket No. 09–52, FCC 11–28. On December 28, 2011, the Commission adopted a Third Report and Order in MB Docket No. 09–52, FCC 11–190 (''Third R&O''). In the Third R&O the Commission further refined the use of the Tribal Priority in the commercial FM context, specifically adopting a ''threshold qualifications'' approach to commercial FM application processing.

In the commercial FM context, the Tribal Priority is applied at the allotment stage of the licensing process. A Tribe or Tribal entity initiates the process by petitioning that a new Tribal Allotment be added to the FM Table of Allotments using the Tribal Priority. A petitioner seeking to add a Tribal Allotment to the FM Table of Allotments, like all other FM allotment proponents, must file FCC Form 301 when submitting its Petition for Rule Making. Under the new ''threshold qualification'' procedures adopted in the Third R&O, once a Tribal Allotment has been successfully added to the FM Table of Allotments using the Tribal Priority through an FM allocations rulemaking, the Commission will announce by Public Notice a Threshold Qualifications Window (''TQ Window''). During the TQ Window, any Tribe or Tribal entity that could qualify to add that particular Tribal Allotment may file an FCC Form 301 application for that Tribal Allotment. Such an applicant must demonstrate that it meets all of the eligibility criteria for the Tribal Priority, just as the original Tribal Allotment proponent did at the allotment stage. If it wishes its previously filed Form 301 application to be considered at this stage, then during the TQ Window the original Tribal Allotment proponent must submit notice to process its pending Form 301 application immediately.

If only one acceptable application is filed during the TQ Window, whether by the original Tribal allotment proponent submitting notification to process its previously filed Form 301, or by another qualified applicant, that application will be promptly processed and the Tribal Allotment will not be auctioned. In the event that two or more acceptable applications are filed during the TQ Window, the Commission will announce a limited period in which the parties may negotiate a settlement or bona fide merger, as a way of resolving the mutual exclusivity between their applications. If a settlement or merger is reached, the parties must notify the Commission and the staff will process the surviving application pursuant to the settlement or merger. If a settlement cannot be reached among the mutually exclusive applicants, the Tribal Allotment will be auctioned during the next scheduled FM auction. At that time, only the applicants whose applications were accepted for filing during the TQ Window, as well as the original Tribal Allotment proponent, will be permitted to bid on that particular Tribal Allotment. This closed group of mutually exclusive TQ Window applicants must comply with applicable established auction procedures.

In the event that no qualifying party applies during the TQ Window, and the original Tribal allotment proponent requests that its pending Form 301 application not be immediately processed, the Tribal Allotment will be placed in a queue to be auctioned in the normal course for vacant FM allotments. When the Tribal Allotment is offered at auction for the first time, only applicants meeting the ''threshold qualifications'' may specify that particular Tribal Allotment on FCC Form 175, Application to Participate in an FCC Auction (OMB Control No. 3060–0600). Should no qualifying party apply to bid or qualify to bid on a Tribal Allotment in the first auction in which it is offered, then the Tribal allotment will be offered in a subsequent auction and any applicant, whether or not a Tribal entity, may apply for the Tribal Allotment.

Consistent with actions taken by the Commission in the Third R&O, Form 301 has been revised to accommodate applicants applying in a TQ Window for a Tribal Allotment. As noted above, an applicant applying in the TQ Window, who was not the original proponent of the Tribal Allotment at the rulemaking stage, must demonstrate that it would have qualified in all respects to add the particular Tribal Allotment for which it is applying. Form 301 contains a new question in Section II—Legal titled ''Tribal Priority-Threshold Qualifications.'' An applicant answering ''yes'' to the question must provide an Exhibit demonstrating that it meets all of the Tribal Priority eligibility criteria. The Instructions for the Form 301 have been revised to assist applicants with completing the responsive Exhibit.

In addition, Form 301 contains a new option under Section I—General Information—Application Purpose, titled ''New Station with Petition for Rulemaking to Amend FM Table of Allotments using Tribal Priority.'' A petitioner seeking to add a Tribal Allotment to the FM Table of Allotments must file Form 301 when submitting its Petition for Rule Making. This new Application Purpose field will assist the staff in quickly identifying Form 301 applications filed in connection with a petition to add a Tribal Allotment and initiating the ''threshold qualification'' procedures.

This information collection is being revised to accommodate applicants applying in a Threshold Qualifications Window for a Tribal Allotment that had been added to the FM Table of Allotments using the Tribal Priority under the new ''threshold qualifications'' procedures adopted in the Third R&O.

OMB approved the information collection requirements and form revisions for this collection on April 27, 2012.

Federal Communications Commission.

Bulah P. Wheeler,

Deputy Manager, Office of the Secretary, Office of Managing Director.

[FR Doc. 2012–13130 Filed 5–30–12; 8:45 am]

BILLING CODE 6712–01–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 635

RIN 0648–XC044

Atlantic Highly Migratory Species; Commercial Porbeagle Shark Fishery Closure

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

ACTION: Temporary rule; fishery closure.

SUMMARY: NMFS is closing the commercial fishery for porbeagle sharks. This action is necessary because landings for the 2012 fishing season have reached at least 80 percent of the available quota.

DATES: The commercial porbeagle shark fishery is closed effective 11:30 p.m. local time May 30, 2012, until, and if, NMFS announces in the **Federal Register** that additional quota is available and the season is reopened.

FOR FURTHER INFORMATION CONTACT: Karyl Brewster-Geisz or Peter Cooper, 301–427–8503; fax 301–713–1917.

SUPPLEMENTARY INFORMATION: The Atlantic shark fisheries are managed under the 2006 Consolidated Atlantic Highly Migratory Species (HMS) Fishery Management Plan (FMP), its amendments, and its implementing regulations found at 50 CFR part 635 issued under authority of the Magnuson-Stevens Fishery Conservation and Management Act (16 U.S.C. 1801 *et seq.*).

Under § 635.5(b)(1), shark dealers are required to report to NMFS all sharks landed every two weeks. Dealer reports for fish received between the 1st and 15th of any month must be received by NMFS by the 25th of that month. Dealer reports for fish received between the 16th and the end of any month must be received by NMFS by the 10th of the following month. Under § 635.28(b)(2), when NMFS projects that fishing season landings for a species group have reached or are about to reach 80 percent of the available quota, NMFS will file for publication with the Office of the Federal Register a closure action for that shark species group that will be effective no fewer than 5 days from the date of filing. From the effective date and time of the closure until NMFS announces in the **Federal Register** that additional quota is available and the season is reopened, the fishery for that species group is closed, even across fishing years.

On January 24, 2012 (77 FR 3393), NMFS announced that the porbeagle shark fishery for the 2012 fishing year was open and the available porbeagle shark quota was 0.7 metric tons (mt) dressed weight (dw) (1,585 lb dw). Dealer reports through May 17, 2012, indicate that 0.67 mt dw or 93.3 percent of the available quota for porbeagle sharks has been landed. Dealer reports received to date indicate that 4.3 percent of the quota was landed from the opening of the fishery on January 24, 2012, through March 6, 2012; 12.2 percent of the quota was landed from March 7, 2012, through March 28, 2012; 5.7 percent was landed from March 29, 2012, through April 17, 2012; and 71.1 percent of the quota was landed from April 18, 2012, through May 17, 2012. The fishery has reached 93.3 percent of the quota, which exceeds the 80 percent limit specified in the regulations. Accordingly, NMFS is closing the commercial porbeagle shark fishery as of 11:30 p.m. local time May 30, 2012. This closure does not affect any other shark fishery.

During the closure, retention of porbeagle sharks is prohibited for persons fishing aboard vessels issued a commercial shark limited access permit under 50 CFR 635.4, unless the vessel is properly permitted to operate as a charter vessel or headboat for HMS and is engaged in a for-hire trip, in which case the recreational retention limits for sharks and ''no sale'' provisions apply (50 CFR 635.22(a) and (c)). A shark dealer issued a permit pursuant to § 635.4 may not purchase or receive porbeagle sharks from a vessel issued an Atlantic shark limited access permit (LAP), except that a permitted shark dealer or processor may possess porbeagle sharks that were harvested, off-loaded, and sold, traded, or bartered, prior to the effective date of the closure and were held in storage. Under this closure, a shark dealer issued a permit pursuant to § 635.4 may, in accordance with state regulations, purchase or receive a porbeagle sharks if the sharks were harvested, off-loaded, and sold, traded, or bartered from a vessel that fishes only in state waters and that has not been issued an Atlantic Shark LAP, HMS Angling permit, or HMS Charter/Headboat permit pursuant to § 635.4.

Classification

Pursuant to 5 U.S.C. 553(b)(B), the Assistant Administrator for Fisheries, NOAA (AA), finds that providing for prior notice and public comment for this action is impracticable and contrary to the public interest because the fishery is currently underway, and any delay in this action would cause overharvest of the quota and be inconsistent with management requirements and objectives. If the quota is exceeded, the affected public is likely to experience reductions in the available quota and a lack of fishing opportunities in future seasons. For these reasons, the AA also finds good cause to waive the 30-day delay in effective date pursuant to 5 U.S.C. 553 (d)(3). This action is required under § 635.28(b)(2) and is exempt from review under Executive Order 12866.

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

Dated: May 24, 2012.

Carrie Selberg,

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

[FR Doc. 2012–13190 Filed 5–25–12; 4:15 pm]

BILLING CODE 3510–22–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 679

[Docket No. 111213751–2102–02]

RIN 0648–XC052

Fisheries of the Exclusive Economic Zone Off Alaska; Northern Rockfish in the Bering Sea and Aleutian Islands Management Area

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

ACTION: Temporary rule; modification of closure.

SUMMARY: NMFS is opening directed fishing for northern rockfish in the Bering Sea and Aleutian Islands Management Area (BSAI). This action is necessary to fully use the 2012 total allowable catch (TAC) of northern rockfish in the BSAI.

DATES: Effective 1200 hrs, Alaska local time (A.l.t.), May 25, 2012, through 2400 hrs, A.l.t., December 31, 2012. Comments must be received at the following address no later than 4:30 p.m., A.l.t., June 11, 2012.

ADDRESSES: You may submit comments on this document, identified by RIN 0648–XC052, by any of the following methods:

- *Electronic Submission:* Submit all electronic public comments via the Federal e-Rulemaking Portal *www.regulations.gov.* To submit comments via the e-Rulemaking Portal, first click the ''submit a comment'' icon, then enter RIN 0648–XC052 in the keyword search. Locate the document you wish to comment on from the resulting list and click on the ''Submit a Comment'' icon on that line.
- *Mail:* Address written comments to Glenn Merrill, Assistant Regional Administrator, Sustainable Fisheries Division, Alaska Region NMFS, Attn: Ellen Sebastian. Mail comments to P.O. Box 21668, Juneau, AK 99802–1668.
- *Fax:* Address written comments to Glenn Merrill, Assistant Regional Administrator, Sustainable Fisheries Division, Alaska Region NMFS, Attn: Ellen Sebastian. Fax comments to 907–586–7557.
- *Hand delivery to the Federal Building:* Address written comments to Glenn Merrill, Assistant Regional Administrator, Sustainable Fisheries Division, Alaska Region NMFS, Attn: Ellen Sebastian. Deliver comments to 709 West 9th Street, Room 420A, Juneau, AK.

Instructions: Comments must be submitted by one of the above methods to ensure that the comments are received, documented, and considered by NMFS. Comments sent by any other method, to any other address or individual, or received after the end of the comment period, may not be considered. All comments received are a part of the public record and will generally be posted for public viewing on *www.regulations.gov* without change. All personal identifying information (e.g., name, address) submitted voluntarily by the sender will be publicly accessible. Do not submit confidential business information, or otherwise sensitive or protected information. NMFS will accept anonymous comments (enter ''N/A'' in the required fields if you wish to remain anonymous). Attachments to electronic comments will be accepted in Microsoft Word or Excel, WordPerfect, or Adobe PDF file formats only.

FOR FURTHER INFORMATION CONTACT: Steve Whitney, 907–586–7269.

SUPPLEMENTARY INFORMATION: NMFS manages the groundfish fishery in the BSAI according to the Fishery Management Plan for Groundfish of the Bering Sea and Aleutian Islands Management Area (FMP) prepared by the North Pacific Fishery Management Council under authority of the Magnuson-Stevens Fishery Conservation and Management Act. Regulations governing fishing by U.S. vessels in accordance with the FMP appear at subpart H of 50 CFR part 600 and 50 CFR part 679.

Pursuant to the final 2012 and 2013 harvest specifications for groundfish in the BSAI (77 FR 10669, February 23, 2012), NMFS closed the directed fishery for northern rockfish under 679.2(d)(1)(iii).

As of May 23, 2012, NMFS has determined that approximately 4,308 metric tons of northern rockfish remain unharvested in the BSAI. Therefore, in accordance with § 679.25(a)(1)(i), (a)(2)(i)(C) and (a)(2)(iii)(D), and to fully utilize the 2012 TAC of northern rockfish in the BSAI, NMFS is terminating the previous closure and is opening directed fishing for northern rockfish in the BSAI. This will enhance the socioeconomic well-being of harvesters in this area. The Administrator, Alaska Region (Regional Administrator) considered the following factors in reaching this decision: (1) The current catch of northern rockfish in the BSAI and, (2) the harvest capacity and stated intent on future harvesting patterns of vessels in participating in this fishery.

Classification

This action responds to the best available information recently obtained from the fishery. The Acting Assistant Administrator for Fisheries, NOAA (AA), finds good cause to waive the requirement to provide prior notice and opportunity for public comment pursuant to the authority set forth at 5 U.S.C. 553(b)(B) and 679.25(c)(1)(ii) as such requirement is impracticable and contrary to the public interest. This requirement is impracticable and contrary to the public interest as it would prevent NMFS from responding to the most recent fisheries data in a timely fashion and would delay the opening of northern rockfish in the BSAI. NMFS was unable to publish a notice providing time for public comment because the most recent, relevant data only became available as of May 23, 2012.

The AA also finds good cause to waive the 30-day delay in the effective date of this action under 5 U.S.C. 553(d)(3). This finding is based upon the reasons provided above for waiver of prior notice and opportunity for public comment.

Without this inseason adjustment, NMFS could not allow the fishery for northern rockfish in the BSAI to be harvested in an expedient manner and in accordance with the regulatory schedule. Under § 679.25(c)(2), interested persons are invited to submit written comments on this action to the above address until June 11, 2012.

This action is required by§ 679.20 and § 679.25 and is exempt from review under Executive Order 12866.

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

Dated: May 25, 2012.

Carrie Selberg,

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

[FR Doc. 2012–13221 Filed 5–25–12; 4:15 pm]

BILLING CODE 3510–22–P

Federal Register
Vol. 77, No. 105
Thursday, May 31, 2012

Proposed Rules

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 ENERGY

10 CFR Parts 429, 430, and 431

[Docket No. EERE–2011–BT–TP–0024]

RIN 1904–AC46

Energy Conservation Program: Alternative Efficiency Determination Methods and Alternative Rating Methods

AGENCY: Office of Energy Efficiency and Renewable Energy, Department of Energy.

ACTION: Notice of proposed rulemaking.

SUMMARY: The U.S. Department of Energy (DOE) is proposing to revise and expand its existing regulations governing the use of particular methods as alternatives to testing for the purposes of certifying compliance with the applicable energy conservation standards and the reporting of related ratings for certain consumer products and commercial and industrial equipment covered by energy conservation standards.

DATES: DOE will accept comments, data, and information regarding this notice of proposed rulemaking (NOPR) no later than July 2, 2012. See section V, ''Public Participation,'' of this NOPR for details.

ADDRESSES: Interested persons are encouraged to submit comments using the Federal eRulemaking Portal at *http://www.regulations.gov.* Follow the instructions for submitting comments. Alternatively, interested persons may submit comments, identified by docket number EERE-2011-BT-TP-0024, by any of the following methods:

- *Email:* to *AED/ARM–2011–TP–0024@ee.doe.gov.* Include EERE-2011-BT-TP-0024 in the subject line of the message.
- *Mail:* Ms. Brenda Edwards, U.S. Department of Energy, Building Technologies Program, Mailstop EE–2J, Revisions to Energy Efficiency Enforcement Regulations, EERE–2011–BT–TP–0024, 1000 Independence Avenue SW., Washington, DC 20585–0121. Phone: (202) 586–2945. Please submit one signed paper original.
- *Hand Delivery/Courier:* Ms. Brenda Edwards, U.S. Department of Energy, Building Technologies Program, 6th Floor, 950 L'Enfant Plaza, SW., Washington, DC 20024. Phone: (202) 586–2945. Please submit one signed paper original.

Instructions: All submissions received must include the agency name and docket number or RIN for this rulemaking.

Docket: For access to the docket to read background documents, or comments received, go to the Federal eRulemaking Portal at *http://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Ms. Ashley Armstrong, U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, Building Technologies Program, EE–2J, 1000 Independence Avenue SW., Washington, DC 20585–0121. Telephone: 202–586–6590. Email: *Ashley.Armstrong@ee.doe.gov;* and Ms. Laura Barhydt, U.S. Department of Energy, Office of the General Counsel, Forrestal Building, GC–32, 1000 Independence Avenue SW., Washington, DC 20585. Telephone: (202) 287–5772. Email: *Laura.Barhydt@hq.doe.gov.*

SUPPLEMENTARY INFORMATION:

I. Authority and Background

A. Authority

Title III of the Energy Policy and Conservation Act of 1975, as amended (''EPCA'' or, in context, ''the Act'') sets forth a variety of provisions designed to improve energy efficiency. Part A of Title III (42 U.S.C. 6291–6309) provides for the Energy Conservation Program for Consumer Products Other Than Automobiles. The National Energy Conservation Policy Act (NECPA), Pub. L. 95–619, amended EPCA to add Part A–1 of Title III, which established an energy conservation program for certain industrial equipment. (42 U.S.C. 6311–6317) [1] The Department of Energy (''DOE'') is charged with implementing these provisions.

Under EPCA, this program consists essentially of four parts: (1) Testing; (2) labeling; (3) Federal energy conservation standards; and (4) certification and enforcement procedures. The Federal Trade Commission (FTC) is primarily responsible for labeling consumer products, and DOE implements the remainder of the program. The testing requirements consist of test procedures that manufacturers of covered products and equipment must use (1) as the basis for certifying to DOE that their products comply with the applicable energy conservation standards adopted under EPCA, and (2) for making representations about the efficiency of those products and equipment. Similarly, DOE must use these test requirements to determine whether the products comply with any relevant standards promulgated under EPCA. For certain consumer products and commercial equipment, DOE's existing testing regulations include allowing the use of an alternative efficiency determination method (AEDM) or an alternative rating method (ARM), in lieu of actual testing, to simulate the energy consumption or efficiency of certain basic models of covered products under DOE's test procedure conditions.

B. Background

AEDMs and ARMs are computer modeling or mathematical tools that predict the performance of non-tested basic models. They are derived from mathematical models and engineering principles that govern the energy efficiency and energy consumption characteristics of a type of covered product. (In the context of this discussion, the term ''covered product'' applies both to consumer products and commercial equipment that are covered under EPCA.) These computer modeling and mathematical tools, when properly developed, can provide a relatively straight-forward and reasonably accurate means to predict the energy usage or efficiency characteristics of a basic model of a given covered product.

Where authorized by regulation, AEDMs and ARMs enable manufacturers to rate and certify their basic models by using the projected energy use or energy efficiency results derived from these simulation models. DOE has authorized the use of AEDMs or ARMs for certain covered products that are difficult or expensive to test in an effort to reduce the testing burden faced by the manufacturers of expensive

[1] For editorial reasons, Parts B (consumer products) and C (commercial equipment) of Title III of EPCA were re-designated as parts A and A–1, respectively, in the United States Code.

or highly customized basic models. The primary difference between these two simulation methods is that ARMs must be approved by DOE prior to use while AEDMs do not require prior DOE approval. From a technical perspective, there are no substantive differences between these two simulation methods. DOE's regulations currently permit manufacturers of commercial heating, ventilation and air-conditioning (HVAC) equipment, commercial water heating (WH) equipment, distribution transformers, and electric motors to use AEDMs, while manufacturers of residential central air conditioners (CACs) and central heat pumps (CHPs) may use an ARM to rate their non-tested combinations.

DOE believes other similar products that must currently be rated and certified through testing, such as commercial refrigeration equipment, automatic commercial ice makers, beverage vending machines, walk-in cooler and freezer refrigeration systems and small electric motors, could also be rated and certified through the use of computer or mathematical modeling. Permitting the use of these modeling techniques for certification and rating purposes would require DOE to explicitly permit manufacturers to use an AEDM or ARM through regulation. DOE sought comment on this topic and other issues in a Request for Information (RFI), which was published in the **Federal Register** on April 18, 2011. 76 FR 21673.

The RFI requested suggestions, comments, and information relating to the Department's intent to expand and revise its existing AEDM and ARM requirements for consumer products and commercial and industrial equipment covered under EPCA. This rulemaking is intended to facilitate DOE's consideration of procedural changes to its requirements for AEDMs and ARMs in an effort to advance the effective implementation of DOE's conservation standards and regulations. The comment period for written submissions on the RFI closed on May 18, 2011. This notice proposes to modify those regulations pertaining to the AEDM and ARM requirements within Part 429 of Title 10 of the Code of Federal Regulations (CFR). The Department's goal is to establish a uniform, systematic, and fair approach to the use of these types of modeling techniques that will enable DOE to ensure that products in the marketplace are correctly rated—irrespective of whether they are subject to actual physical testing or are rated using modeling—without unnecessarily burdening regulated entities.

II. Discussion of Specific Revisions to DOE's Alternative Efficiency Determination Methods and Alternative Rating Methods Regulations and Comments Received in Response to the RFI

DOE received comments from 21 interested parties, including manufacturers, trade associations, and advocacy groups. Specifically, Table II.1 lists the entities that submitted comments and their affiliation. These comments are discussed in more detail below, and the full set of comments can be found at: *http://www.regulations.gov/#!docketDetail;dct=FR%252BPR%252BN%252BO%252BSR%252BPS;rpp=25;po=0;D=EERE-2011-BT-TP-0024.*

TABLE II.1—STAKEHOLDERS THAT SUBMITTED COMMENT ON THE RFI

Name	Acronym	Organization type
Air-Conditioning, Heating, and Refrigeration Institute	AHRI	Industry Trade Group.
American Council for an Energy Efficient Economy, Appliance Standards Awareness Project, and Natural Resources Defense Council.	ACEEE, ASAP, and NRDC (Joint Comment).	Advocacy Group.
American Panel Corporation	American Panel	Manufacturer of refrigeration panels.
Bradford White Water Heaters	Bradford White	Manufacturer of water heaters.
Carrier Corporation	Carrier	Manufacturer of Air Conditioning and Heating Equipment.
Earthjustice	Earthjustice	Advocacy Group.
First Company	First	Manufacturer of Air Conditioning and Heating Equipment.
Goodman Manufacturing Company	Goodman	Manufacturer of Air Conditioning and Heating Equipment.
Heatcraft Refrigeration Products	Heatcraft	Manufacturers of Commercial Refrigeration Equipment.
Howe Corporation	Howe	Manufacturer of Automatic Commercial Ice Makers.
Hussmann	Hussmann	Manufacturer of Air Conditioning and Heating Equipment and CRE.
Lennox International, Inc	Lennox	Manufacturers of Air Conditioning and Heating Equipment.
Mitsubishi Electric and Electronics USA, Inc	MEUS	Manufacturer of Air Conditioning and Heating Equipment.
Modine Manufacturing Company	Modine	Manufacturer of Air Conditioning and Heating Equipment.
National Electrical Manufacturers Association	NEMA	Industry Trade Group.
Natural Resources Defense Council	NRDC	Advocacy Group.
Omega Magnetics Engineering, LLC	Omega	Manufacturer of Distribution Transformers.
PVI Industries, LLC	PVI	Manufacturer of Commercial Water Heaters.
Scotsman Ice Systems	Scotsman	Manufacturer of Automatic Commercial Ice Makers.
Structural Concepts Corporation	Structural Concepts	Manufacturer of CRE.
Traulsen	Traulsen	Manufacturer of Air Conditioning and Heating Equipment and CRE.

A. Distinction Between Alternative Efficiency Determination Method and Alternative Rating Method

1. Naming Convention

DOE is contemplating combining AEDMs and ARMs under a single term to avoid confusion, particularly with respect to air conditioning products that currently are subject to different regulations depending on whether the unit is consumer or commercial. The RFI sought comment on the need to have two alternatives to testing or if both alternative methods could be covered by one term with the inclusion of additional product specific requirements.

Both Carrier and AHRI believe the distinction is necessary because ARMs require the highest sales volume tested combination for the indoor coil, while AEDMs are better for low volume, high variety commercial products where testing multiple samples is not feasible. (Carrier, No. 7.1 at p. 2; AHRI, No. 17.1 at p. 3) Lennox and Mitsubishi agreed and pointed out that the two methods are designed for different purposes, applications and capacity ranges. (Lennox, No. 16.1 at p. 1; Mitsubishi, No. 19.1 at p. 1) PVI Industries provided a similar observation that an ARM allows for adjustments to address a shortcoming of the test method, while AEDMs are calculated substitutes for testing. (PVI Industries, No. 15.1 at p. 3)

However, not all stakeholders agreed with the need for separately named methods. Hussmann commented that only AEDMs are needed, and Goodman stated that in order to reduce confusion there should only be one method, which should be ARMs because they have been in place for years. (Hussmann, No. 10.1 at p. 1; Goodman, No 2.1 at p. 1)

DOE tentatively agrees with the commenters suggesting a single term to apply to those modeling techniques used to rate and certify any covered products that would be permitted to use these alternate methods. DOE intends to use AEDM, instead of ARM, to refer to these methods because the provisions DOE proposes to adopt are more similar to the current provisions for AEDMs. DOE also notes that the term ARM is used only for simulations used by manufacturers of residential air conditioners and heat pumps, whereas AEDMs are used by a wider range of industries. Given that these two methods are conceptually identical, DOE is applying the term ''AEDM'' to refer to any simulation method used to determine the efficiency or energy usage of a given product or equipment. DOE, however, agrees with Carrier, AHRI, Lennox, and Mitsubishi in that there are product-specific considerations that should guide the development and application of an AEDM. In response to these comments, DOE is proposing product-specific substantiation requirements in this notice which DOE believes will address the concerns about the current differences between the two methods.

2. Pre-Approval by the Department

In light of the approval process currently in place for ARMs, DOE's RFI sought comment regarding the feasibility of applying a similar requirement for AEDMs or, alternatively, eliminating the approval process for ARMs. EarthJustice supported the adoption of a prior approval-type process. (EarthJustice, No. 21.1 at p. 2) American Panel also supported this approach and noted that it would give both manufacturers and DOE a level of security regarding the development of testing simulations. (American Panel, No. 3.1 at p. 2) Zero Zone echoed this view, expressing support for a ''pre-approved'' option since it would reduce the likelihood of a given manufacturer using an ''unapproved'' AEDM. (Zero Zone, No. 18.1 at p. 7) Similarly, both Hussmann and Goodman asserted that pre-approval would provide manufacturers with confidence in their programs. (Hussmann, No. 10.1 at p. 2; Goodman, No. 2.1 at p. 1) Additionally, Bradford White viewed pre-approval as a way to prevent certain manufacturers from having an unfair advantage by incorrectly rating their products. (Bradford White, No. 5.1 at p. 1)

Despite these expressions of support for a pre-approval process, others identified potential problems with this approach. NEMA stated that there is no perceived benefit in DOE imposing an additional burden on both the manufacturer and itself. Requiring prior approval would, in its view, place an inordinate burden on manufacturers. (NEMA, No. 20.1 at pp. 3–4; NEMA, No. 22.1 at p. 2) Modine commented that there is no need for pre-approval because it is the manufacturer's responsibility to produce and certify products that comply. (Modine, No. 8.1 at p. 2) Heatcraft remarked that a pre-approval requirement is unnecessary and the imposition of one would likely overwhelm DOE by virtue of the number of submitted pre-approval requests. (Heatcraft, No. 11.1 at p. 3) Carrier expressed concern with the potential burden involved with a pre-approval process and indicated that requiring pre-approval can result in time-to-market delays (i.e., delays in getting new products to market for sale). (Carrier, No. 7.1 at p. 6) This view was supported by Lennox, Traulsen, PVI Industries, AHRI, Zero Zone, and Mitsubishi. (Lennox, No. 16.1 at p. 2; Traulsen, No. 9 at p. 4; PVI Industries, No. 15.1 at p. 4; AHRI, No. 17.1 at p. 4; Zero Zone, No. 18.1 at p. 7; Mitsubishi, No. 19.1 at pp. 2–3) Further, Structural Concepts expressed concern that pre-approval would limit innovation with respect to the introduction of new designs and technologies, while PVI Industries mentioned that pre-approval would discourage product innovation. (Structural Concepts, No. 26.1 at p. 2; PVI Industries, No. 15.1 at p. 4)

While a broad AEDM pre-approval process could help provide manufacturers with an added sense of security that their AEDMs comply with DOE's requirements, the available facts indicate that this added benefit would be unlikely to outweigh both the additional burden placed on manufacturers and DOE as well as the drawbacks inherent with increased market delays created by requiring a pre-approval process. DOE notes that the substantiation process, an integral part of the validation of the AEDM, should provide manufacturers and consumers with confidence in ratings derived from the AEDM. The substantiation process requires a manufacturer to test several basic models to validate the accuracy of the AEDM, making DOE pre-approval unnecessary. Furthermore, DOE uses a self-certification process for most covered products, whereby manufacturers are responsible for ensuring that the testing is done in accordance with DOE's regulations. The Department does not review all manufacturers' test data to confirm that the testing was performed correctly and that the basic model was rated correctly; therefore, an approval process for AEDMs could be construed as an advantage to those manufacturers who are permitted to use them. In light of these factors, as well as the potential risks that manufacturers face for using an inaccurate or otherwise faulty AEDM, which includes civil penalties and prohibitions on marketing noncompliant products, DOE is not proposing to add a pre-approval process for AEDMs and is proposing to drop the current pre-approval requirement for methods used to rate residential central air conditioners and heat pumps. While DOE does not plan to review AEDMs prior to their use, DOE may request the records underlying the use of an AEDM at any time. 10 CFR 429.71. Manufacturers must retain any records of testing performed to support the use of an AEDM. Id.

DOE requests comment on its proposal to continue omitting a pre-approval process for AEDMs, and to no longer require pre-approval for rating methods applied to residential central air conditioners and heat pumps. (See Issue 1 under ''Issues on Which DOE Seeks Comment'' in section IV.B of this NOPR.)

B. Products Covered by Alternative Efficiency Determination Methods and Alternative Rating Methods

1. Expansion of Coverage

Under the current DOE regulations, manufacturers of five types of commercial equipment are permitted to use AEDMs to generate the certified ratings of untested basic models, while manufacturers of residential central air conditioners and heat pumps are permitted to use ARMs to generate the certified ratings of untested basic models. As part of this rulemaking, DOE is proposing to expand the types of commercial equipment that would be addressed by these proposed AEDM provisions. However, in the consumer product context, DOE has tentatively decided not to expand the application of AEDMs beyond central air conditioners and heat pumps.

American Panel commented that walk-in coolers and freezers (collectively, ''walk-ins'' or ''WICFs'') should be allowed to use AEDMs for determining the envelope heat transfer characteristics and in selecting the condensing unit and evaporator coil. (American Panel, No. 3.1 at p. 1) Similarly, Zero Zone, Hussmann, PVI Industries, and Structural Concepts remarked that commercial refrigeration equipment (CRE) would also benefit from the use of AEDMs. (Zero Zone, No. 18.1 at p. 2; Hussmann, No. 10.1 at p. 1; PVI Industries, No. 15.1 at p. 2; Structural Concepts, No. 26.1 at p. 2) PVI Industries also suggested extending AEDM coverage to automated commercial ice-makers (ACIMs) and residential water heaters. (PVI Industries, No. 15.1 at p. 2) AHRI concurred with the need to permit the use of AEDMs for walk-ins, CRE units, ACIMs, and commercial water heaters but also indicated that manufacturers of residential boilers and water heaters, furnaces, pool heaters and direct heating equipment should also be permitted to use AEDMs to certify and rate those products. (AHRI, No. 17.1 at p. 2) Zero Zone and Structural Concepts went further and favored permitting the use of AEDMs for all products. (Zero Zone, No. 18.1 at p. 2; Structural Concepts, No. 26.1 at p. 1) Scotsman asserted that AEDMs are not cost-effective for ACIMs because some ACIMs have non-steady operation, which makes them difficult to model with accuracy. It added that testing is not overly burdensome for ACIM manufacturers to conduct. (Scotsman, No. 6.1 at p. 1)

Numerous commenters also stressed that DOE should continue permitting manufacturers to use AEDMs or ARMs with respect to those products that the agency currently permits to be certified and rated with these alternative methods. (Carrier, No. 7.1 at p. 1; Mitsubishi, No 19.1 at p. 1; Heatcraft, No. 11.1 at p. 1; Lennox, No. 13.1 at p. 2; PVI Industries, No. 15.1 at p. 2; Lennox, No. 16.1 at p. 1; AHRI, No. 17.1 at pp. 2,4; NEMA, No. 20.1 at p. 2; NEMA, No. 22.1 at p. 2; Bradford White, No 5.1 at p. 1) Modine, NRDC, ACEEE, ASAP and Traulsen did not provide product-specific recommendations, but commented that large, low-volume, custom equipment manufacturers would benefit from AEDM use. (Modine, No. 8.1 at p. 1; Traulsen, No. 9.1 at p. 2; Joint Comment, No. 24.1 at p. 2)

DOE has conducted a number of rulemaking activities examining the manner in which manufacturers of a variety of products test and rate their products. These activities have addressed products such as CRE, ACIMs, small electric motors, beverage vending machines (BVMs), and walk-ins. Based on substantial amounts of information that DOE has collected through these rulemaking activities, DOE ascertained that many basic models of these product types have low sales volumes or are custom-built, meaning that manufacturers may have a large number of basic models that they would need to test in order to certify compliance under DOE's current requirements. Given the potential for a high testing burden, manufacturers of these products may benefit from the use of an AEDM since it could be used to simulate testing under DOE test conditions and the results could then be used to certify compliance in lieu of conducting the testing that is currently required. Adopting this approach will likely significantly reduce manufacturer testing burdens by minimizing the number of units that a manufacturer must physically test in order to certify all of the basic models offered for sale in the U.S. As a result, in addition to those products that are already permitted to be rated and certified using modeling methods (i.e., commercial HVAC and WH equipment, electric motors, and distribution transformers), DOE is proposing to allow the manufacturers of CRE, ACIMs, small electric motors, and BVMs to use AEDMs to rate and certify their products. Permitting this option should enable these manufacturers to reduce the overall testing burdens that they would otherwise face.

Additionally, DOE is proposing to allow the use of AEDMs for WICFs but is limiting this proposal to apply only to the WICF refrigeration system. As with other types of commercial equipment for which DOE is proposing to expand the voluntary use of AEDMs, WICF refrigeration systems are low-volume and custom-made for the specific installation and could be accurately rated using a computer simulation to predict their behavior under DOE test conditions. DOE is not proposing to permit a similar option for other WICF components. WICF panels are relatively simple pieces of equipment and results from a basic model of a given panel can be extrapolated to many other panel basic models under the provisions of the test procedure. As for WICF doors, the DOE test procedure already provides for the use of certain modeling techniques that are approved by the National Fenestration Rating Council (NFRC), which, in DOE's view, makes a parallel AEDM provision for these components unnecessary. Consequently, DOE's proposal is to expand the use of AEDMs to WICF refrigeration systems because manufacturers of WICF refrigeration systems would benefit from the reduced testing burden that the proposal would provide.

DOE requests comment on its proposal to expand the use of AEDMs to other types of commercial equipment. (See Issue 2 under ''Issues on Which DOE Seeks Comment'' in section IV.B of this NOPR.)

In addition, DOE is proposing to retain its existing regulations that allow for the use of simulation or mathematical models to predict the certified ratings of residential central air conditioners and heat pumps. The split-system air conditioner and heat pump market allows the pairings of a variety of different indoor and outdoor models for installation in a residence. This approach results in a proliferation of basic models for which a manufacturer must determine the correct rating to certify compliance to the Department. If all of these basic model combinations had to be tested, manufacturers of CACs and CHPs would likely face significant increased testing burden. DOE believes it is necessary to continue to allow the use of alternatives to testing to predict the performance of all the different combinations of CACs and CHPs that are offered for sale in the U.S. DOE is clarifying that its proposal allows manufacturers of CACs and CHPs to use an AEDM to predict the energy efficiency of various outdoor units paired with different indoor units as long as the substantiation criteria are met (see section C below for additional discussion).

As for those comments suggesting that DOE expand the use of AEDMs to other consumer products such as residential water heaters and furnaces, DOE does not agree with this approach. Basic models of consumer products such as water heaters and furnaces are typically high-volume, with little to no customization from model-to-model. Many of these products can be found off-the-shelf or are regularly stocked by distributors. As a result, manufacturers of these products do not face the same challenges of testing and rating potentially hundreds of different variations as faced by manufacturers of many commercial products. Unlike manufacturers of many types of commercial equipment that had apparently not performed the required testing of each basic model, manufacturers of consumer products have been regularly conducting the testing necessary to certify compliance to the Department without the use of simulation tools. The Department is unaware of any undue burden caused by testing a large number of basic models, or an issue with obtaining two samples for testing, due to the high-volume nature of the manufacturing for these consumer products.

2. Use Across Product Classes

Because AEDMs are models based on engineering principles, it may be possible to use a single AEDM to simulate testing of basic models from multiple product classes. Since many of the engineering principles underlying the performance characteristics of different pieces of equipment are the same, DOE believes it is reasonable for a manufacturer to develop an AEDM that could apply across multiple product classes and accurately simulate the energy efficiency or energy use of various basic models. An AEDM used to model energy consumption across multiple product classes, however, will be significantly more complex and will have to account for more variables than an AEDM used to model energy consumption within a single product class. While DOE does not want to restrict manufacturer development and use of AEDMs, the inherent complexity of an AEDM used to rate basic models across multiple product classes requires sufficient safeguards to ensure the accuracy of an AEDM with respect to predicting the energy consumption of a basic model from any product class for which the AEDM will be used. Consequently, DOE sought comment on the best approach to verify the accuracy and applicability of AEDMs and ARMs across multiple product classes without unduly burdening manufacturers.

All interested parties who commented on this issue agreed that AEDMs and ARMs can and should be used across multiple product classes. (Goodman, No. 2.1 at p. 1; American Panel, No. 3.1 at p. 2; Bradford White, No. 5.1 at p. 1; Carrier, No. 7.1 at p. 2; Modine, No. 8.1 at p.1; Traulsen, No. 9.1 at p. 2; Hussmann, No. 10.1 at pp. 1–2; Heatcraft, No. 11.1 at p. 2; Lennox, No. 13.1 at p. 2; PVI Industries, No. 15.1 at p. 3; Lennox, No. 16.1 at p. 2; AHRI, No. 17.1 at p. 3; Zero Zone, No. 18.1 at p. 7; Mitsubishi, No. 19.1 at p. 2; NEMA, No. 20.1 at p. 3; Structural Concepts, No. 26.1 at p. 1) However, stakeholders were divided about the need to substantiate the method for every product class. Carrier, Hussmann, AHRI, Mitsubishi and Structural Concepts all commented that the amount of required testing should not depend on the number of covered product classes, while Modine, Lennox, and NEMA noted that AEDMs and ARMs should be verified for each covered product class. (Carrier, No. 7.1 at p. 2; Hussmann, No. 10.1 at pp. 1–2; AHRI, No. 17.1 at p. 3; Mitsubishi, No. 19.1 at p. 2; Structural Concepts, No. 26.1 at p. 1; Modine, No. 8.1 at p. 1; Lennox, No. 13.1 at p. 2; NEMA, No. 20.1 at p. 3)

While DOE acknowledges that AEDMs and ARMs could be applied across product classes, differences in products and operating conditions may hinder the capability of AEDMs to rate products from multiple product classes within the necessary tolerances. DOE believes that manufacturers can build AEDMs that would apply across a variety of product classes and maintain the appropriate tolerances proposed in this NOPR, but DOE also believes that AEDMs should be substantiated in such a manner as to demonstrate that capability. DOE tentatively agrees with the comments, made by Modine, Lennox and NEMA, supporting verification of an AEDM for each product class to which the AEDM will be applied. Consequently, DOE is proposing to require, as part of the substantiation process, testing of at least one basic model from each DOE product class to which the AEDM is to be applied in addition to the other requirements, which are discussed in section II.C. DOE does not believe this added requirement will significantly increase testing burden because, as stated by Goodman, manufacturers should already be continuously validating their AEDMs. (Goodman, No. 2.1 at p. 1) DOE may, however, amend aspects of this proposal based on information and feedback presented by interested parties or that DOE discovers through further research of this issue in preparation of any final rule that may be issued. As a result, DOE urges all interested parties to provide specific and detailed information regarding the proposed substantiation process as well as specific requirements that the agency should consider when developing the final rule.

DOE requests comment on its proposal to require at least one basic model from each product class be tested to substantiate the AEDM. DOE is particularly interested in whether additional clarification is needed for manufacturers of certain covered products to determine all the applicable product classes that would need to be tested to substantiate the AEDM. As part of these comments, the Department is interested in receiving feedback on how manufacturers currently develop any simulation tools to ensure they are applicable across a wide range of product classes. (See Issue 3 under ''Issues on Which DOE Seeks Comment'' in section IV.B of this NOPR.) Based on these comments and data, DOE may consider and adopt other substantiation criteria from those contained in today's proposal that aid manufacturers in identifying the applicable number of product classes required for testing.

C. Substantiation Requirements

1. Alternative Efficiency Determination Method Tolerances

Currently, DOE requires that manufacturers test a specified number of basic models, apply the AEDM to those same basic models, and compare the results. In order to substantiate the AEDM—i.e., validate the accuracy of the model—the results obtained from the AEDM output must be within a specified tolerance of the results obtained from testing. The comparison is generally required between test results for each individual basic model and the AEDM output for the same basic model, as well as between the average of the test results for all tested basic models, and the average of the AEDM output for all tested basic models. For electric motors, a comparison is only required between individual test results and individual AEDM outputs for the basic models tested. For commercial HVAC and water heaters, the AEDM output for each basic model must be within five percent of the tested value, and the overall average of AEDM outputs must be within one percent of the average of tested values. For distribution transformers, the individual tolerance is also five percent, but the overall tolerance is three percent. Electric motors are subject only to an individual tolerance of ten percent between the AEDM and tested values. The current modeling approach for residential central air conditioners and heat pumps do not have any specific required tolerances because the ARM must be approved by DOE prior to use.

Interested stakeholders provided numerous suggestions regarding the appropriate product-specific tolerances. Bradford White and PVI Industries commented that tolerances for commercial water heaters should be five percent because of instrumentation tolerances as well as lab to lab variation. (Bradford White, No. 5.1 at p. 2; PVI Industries, No. 15.1 at p. 5) AHRI commented that the one percent overall tolerance for commercial HVAC and water heaters that currently applies was not appropriate and should be relaxed, while Heatcraft indicated that a one percent overall tolerance is not realistic for walk-ins because of equipment tolerances and testing variation inherent in the test procedure. (AHRI, No. 17.1 at p. 5; Heatcraft, No. 11.1 at p. 4) Additionally, AHRI commented in a later proposal that the individual tolerance for residential and commercial HVAC and WH equipment, ACIMs, walk-ins and commercial refrigeration equipment should be 5 percent. (AHRI, No. 31.1 at p. 3) Regarding HVAC products, Mitsubishi remarked that the tolerance should be 5 percent, and both First Company and Carrier concurred with this suggested level. (Mitsubishi, No. 19.1 at p. 4; First Company, No. 14.1 at p. 3; Carrier, No. 7.1 at p. 5) However, Carrier went further and commented that the overall average of AEDM ratings should be within five percent of the overall average of tested ratings. (Carrier, No. 7.1 at p. 5) NEMA pointed out that electric motor tolerances may need to be tightened to test in accordance with Institute of Electrical and Electronics Engineer (IEEE) Standard 114 or Standard 112 (the two protocols used to measure the efficiency of electric and small electric motors) because these test methods are based on the measured output power divided by input power. (NEMA, No. 20. 1 at pp. 5–6) NEMA also suggested DOE should limit the tolerance for overall averages at three percent for distribution transformers and that the tolerance for individual ratings should allow the AEDM output to be up to 5 percent more efficient than the test results. It added, however, that the tolerance should not apply if the AEDM output was conservative. (NEMA, No. 22.1 at p. 3) Similarly, Modine commented that the output from AEDMs should be permitted for rating purposes only if the AEDM output is no more than five percent more efficient than the tested value. (Modine, No. 8.1 at p. 2) None of these commenters explained the basis for their recommendations.

With respect to CREs, commenter views were even more varied. Traulsen recommended a 15 percent tolerance, while Hussmann suggested that a ten percent tolerance was appropriate. Zero Zone remarked that the tolerance should be five percent. (Traulsen, No. 9.1 at p. 4; Hussmann, No. 10.1 at p. 3; Zero Zone, No. 18.1 at p. 11) None of the commenters specified why they believed their recommended tolerance was appropriate.

Regarding potential tolerance levels for CRE-related AEDMs, there are no technical reasons that would compel the application of larger or less stringent tolerances for these products compared to others. In view of this, and the complete absence at this time of any contradictory data or information that would justify a different approach, DOE is proposing to set individual tolerances between the test results of a basic model and AEDM output for that basic model for CREs at five percent. For the same reasons, DOE is proposing to set this same tolerance for refrigeration systems of walk-ins, BVMs, ACIMs, and residential central air conditioners and heat pumps. DOE is not currently planning to amend the tolerances for electric motors and proposes to apply the same ten percent tolerance to small electric motors.

With respect to distribution transformers, DOE agrees with NEMA's view in favor of an overall tolerance, but disagrees with NEMA's suggestion that the AEDM outputs for individual basic models should be limited only to being no more than five percent more efficient than the test results for that basic model. DOE is concerned with confirming the accuracy of an AEDM and having no tolerance for AEDM outputs that are more conservative than the test results could potentially allow for less accurate results from the AEDMs. Consequently, DOE intends to retain the current tolerance on how much the AEDM output can diverge from the test results.

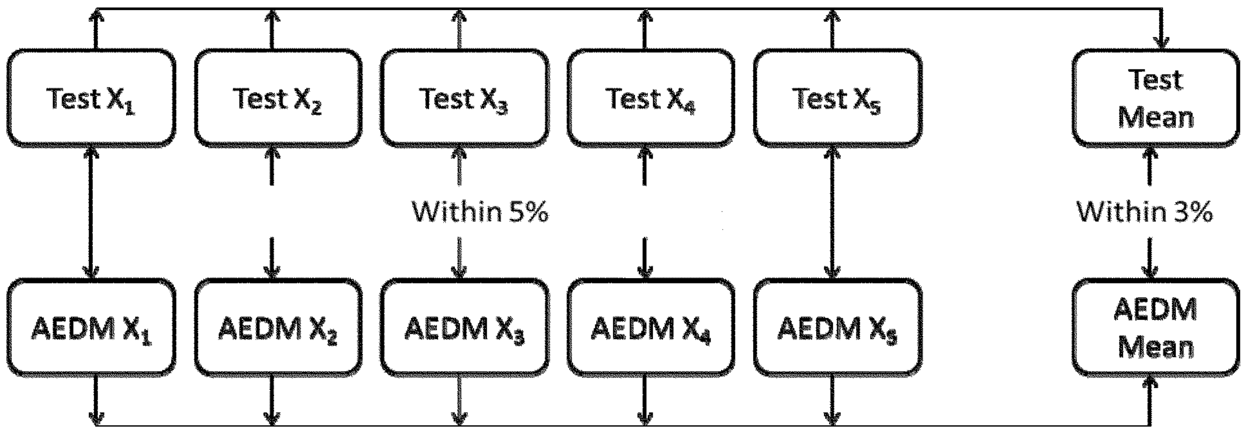
With regard to commercial HVAC equipment, DOE agrees with stakeholders who claimed that the one percent overall average tolerance was unnecessarily stringent. However, DOE disagrees with Carrier's comment suggesting that the overall average tolerance should be five percent. Testing different types of commercial equipment has similar limitations with respect to instrumentation and testing variation in the DOE test procedures as found for other product types, and applying a consistent tolerance across all of these covered products (excluding electric and small electric motors) would help ensure that a consistent, predictable and accurate method is used by manufacturers. This is also seen in the consistency between the certification statistics of different types of commercial air conditioning and heating equipment. Consequently, DOE is proposing to expand this three percent average tolerance to all products that use AEDMs. The overall averages are calculated using the following equation:

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} x_i$$

where $\bar{x}$ is the sample average, n is the number of units tested representing all basic models used to substantiate the AEDM and x_i is the i^{th} sample.

Figure C.1, below, provides a visual representation of DOE's proposed substantiation tolerances for all products proposed for AEDM use, excluding motors and small electric motors.

Figure C.1 Proposed Tolerances for All Products, Except Motors and Small Electric Motors.



*This picture is meant to be an illustrative example of the minimum number of tests needed to substantiate the AEDM and the tolerances that must be satisfied in order to validate the AEDMs results, when there are not a substantial number of product classes..

DOE seeks product specific comments and supporting data on these proposed overall and individual tolerance levels by product type. Specifically, DOE seeks data showing that the variability seen in the manufacturing processes, test instrumentation, and testing procedures merits consideration and adoption of different tolerances. (See Issue 4 under ''Issues on Which DOE Seeks Comment'' in section IV.B of this NOPR.) Based on these data, DOE may consider and adopt different tolerance levels from those contained in today's proposal.

2. Number of Tested Units

In addition to achieving certain tolerances with their AEDMs, manufacturers are required to test a specific number of basic models to demonstrate that the AEDM is sufficiently accurate for determining the ratings of their products. Currently, the required number of models and units that must be tested varies by product and are as follows: Six basic models for commercial HVAC and water heaters; 25 units for distribution transformers (five units of five different basic models); five basic models for electric motors; and four mixed systems for residential central air conditioners and heat pumps. DOE received considerable feedback from interested parties on the necessary sample sizes for these products as well as for other products that manufacturers may be permitted to certify and rate using an AEDM as part of today's proposal.

Bradford White suggested that the appropriate sample size for commercial water heaters is two units, with the smallest and largest input capacity models being tested, and that a manufacturer should not be required to substantiate an AEDM using a number of basic models that a manufacturer does not have in stock. (Bradford White, No. 5.1 at p. 2) PVI agreed that testing two water heaters was adequate for AEDM substantiation. (PVI Industries, No. 15.1 at p. 3) Similarly, Structural Concepts recommended two units as the necessary sample size for CRE, while Hussmann suggested one unit per DOE product class to which the AEDM is applied. (Structural Concepts, No. 26.1 at p. 3; Hussmann, No. 10.1 at p. 3) Regardless of sample size, American Panel cautioned DOE to be aware of the increased cost to manufacturers of testing more units. (American Panel, No. 3.1 at p. 3) NEMA observed that the current sample size and testing for both electric motors and transformers is appropriate. (NEMA, No. 20.1 at p. 4; NEMA, No. 22.1 at p. 3) Carrier mentioned that a sample of three basic models is sufficient and added that DOE should consider permitting manufacturers to decide how to substantiate their AEDMs and how to select models—other than the highest sales volume tested combination—in order to enable them to validate an AEDM across the manufacturer's entire product range. (Carrier, No. 7.1 at p. 4) AHRI submitted a proposal that the sample size for residential and commercial HVAC and WH equipment, ACIMs, walk-ins and CRE should be two units. (AHRI, No. 31.1 at p. 2) However, Lennox remarked that the current sample size for ARMs is reasonable, while Modine supported leaving the decision of how to substantiate an AEDM to the manufacturer. (Lennox, No. 13.1 at p. 4; Modine, No. 8.1 at p. 4) Zero Zone was alone in believing that AEDMs do not need to be substantiated at all. (Zero Zone, No. 18.1 at p. 10)

DOE is reluctant to omit a substantiation process or to leave this process entirely to manufacturer discretion without some form of reasonable confirmation regarding the accuracy and validity of the underlying AEDM. While DOE is sensitive to the costs associated with equipment testing and the fact that some manufacturers may have a high degree of familiarity with how to substantiate their AEDMs, DOE wants to ensure that the AEDM's accuracy is confirmed across the entire range of product classes to which it is applied. Additionally, DOE wants to ensure consistency with regard to the minimum testing requirements needed to substantiate the AEDM across manufacturers of a given equipment type to provide a fair and consistent approach in allowing the use of simulations and mathematical models. For these reasons, DOE is proposing changes to the selection of models used to substantiate an AEDM. Consequently, in DOE's view, to ensure this accuracy, a minimum amount of testing should be conducted to substantiate a given AEDM. Manufacturers may always elect to conduct additional testing to validate the accuracy of the AEDM.

To this end, DOE proposes that at least five basic models be tested to substantiate an AEDM with a minimum of one unit tested of each basic model for all products except distribution transformers. With regard to distribution transformers, DOE proposes to retain the current requirement to test 25 units (five units of five different basic models). DOE also proposes other criteria discussed below that will help ensure that the AEDM is sufficiently reliable for all product classes to which the AEDM will be applied. Consistent with Hussmann's suggestion regarding the number of models that should be tested to substantiate an AEDM, DOE is proposing that at least one basic model be tested from each product class to which the AEDM will be applied as explained above. While differences among products in different product classes may be minimal, DOE wants to ensure that the AEDM is able to account for differences in test conditions for different product classes (*e.g.,* coolers and freezers) and still accurately predict product performance.

Because physical size or capacity is another characteristic that can have a significant effect on efficiency, DOE agrees with Bradford White's suggestion to test both the smallest and largest capacity units covered by the AEDM, where applicable. DOE recognizes, however, that the burden associated with a requirement to test the largest capacity basic model offered may be prohibitive. Therefore, DOE is proposing that the models tested for substantiation include the smallest and largest capacity basic models, or a basic model with a capacity within 25% of the largest capacity basic model, for all products where physical size (e.g., total display area, vendible capacity, rated storage volume, etc.) or capacity (e.g., heating, cooling, etc.) is an integral part of the test procedure and energy use or efficiency of the product. Further, DOE believes that the basic models that meet these capacity criteria should be from the product class that has the highest sales volume because DOE believes these products would be most representative, less likely to be highly customized or built-to-order, and less costly to test.

In addition to this requirement to test models from the highest sales volume product class, DOE proposes that the tested units include the basic model with the highest sales volume in the previous year or is expected to have the highest sales volume as one of the five tested basic models. Lastly, to ensure that the AEDM is substantiated for current, up-to-date models, DOE proposes to require that test data used for substantiation meet the applicable energy conservation standards in effect at the time that the AEDM is being used. Consequently, when the compliance date for amended standards comes into effect, DOE is proposing that manufacturers may need to re-substantiate the AEDM depending on the efficiencies of the basic models used to originally substantiate the AEDM. Table C.1 below summarizes the requirements proposed in this section.

TABLE C.1—PROPOSED REQUIREMENTS FOR SELECTING UNITS FOR SUBSTANTIATION FOR ALL APPLICABLE COVERED PRODUCTS AND EQUIPMENT

Proposed requirement	Applicable products
Test a minimum of five basic models	All.
Test at least one basic model from each product class to which the AEDM will be applied	All.
Test the smallest and largest capacity basic models from the product class with the highest sales volume	Residential AC/HP, Commercial HVAC and WH, ACIM, WICF refrigeration systems, CRE.
Test the basic model with the highest sales volume the previous year, or the basic model which is expected to have the highest sales volume for newly introduced basic models.	All.
Test data used for substantiation must meet applicable Federal energy conservation standards and applicable DOE testing procedures.	All.

DOE seeks comment on the proposed criteria for selecting basic models and the number of basic models that should be required for substantiation as well as whether the differences in testing requirements for distribution transformers are appropriate or necessary. (See Issue 5 under ''Issues on Which DOE Seeks Comment'' in section IV.B of this NOPR.)

3. Required Number of Testing Rounds

To substantiate their AEDMs pursuant to DOE's current regulations, manufacturers of commercial HVAC and water heaters must first apply the AEDM to three or more basic models, which then must be tested. Following this initial round of testing, manufacturers must apply the AEDM to at least three additional models and test them as well. For each round of testing, the ratings predicted by the AEDM must be within a specified percentage of the tested ratings. 10 CFR 429.70. These products are the only products which have to undergo two rounds of testing to substantiate the AEDM. Consequently, DOE is considering altering the number of testing rounds to make AEDM substantiation requirements for these products align with those for other products and sought comment in the RFI on the benefits of a second round of testing because the available data indicate that a reduction in testing burden consistent with DOE's proposal would be unlikely to affect the accuracy of the predicted efficiency levels provided by the appropriate AEDM.

Both Carrier and PVI Industries mentioned that one round of testing is sufficient, while Mitsubishi remarked that two sets of testing do not add any significant benefit. (Carrier, No. 7.1 at p. 6; PVI Industries, No. 15.1 at p. 6; Mitsubishi, No. 19.1 at p. 4) Considering DOE's proposal to change the number of models necessary for substantiation of an AEDM for commercial HVAC and water heaters, DOE believes that the AEDM would be substantiated for every applicable product class following one round of substantiation testing. Given that the manufacturer may test more than the minimum number of basic models during substantiation, DOE believes that a single round of testing is sufficient. Additionally, a manufacturer is free to conduct further testing during the lifetime of an AEDM that is in addition to those substantiation tests being proposed. Requiring this added testing, however, is unnecessary since DOE believes manufacturers are best positioned to assess whether they need to run additional substantiation testing for newly designed or redesigned basic models on a case-by-case basis. DOE is proposing a framework that allows manufacturers to weigh the risk of noncompliance against the increased testing burden and is providing them with the discretion to choose the extent to which they want to conduct additional testing beyond the requirements of this proposal.

Additionally, DOE is proposing new provisions that will require manufacturers to perform additional testing and re-substantiation if changes occur that may impact the validity of the AEDM. These proposals are discussed further below. Because of these additional changes, as well as more stringent substantiation requirements, DOE agrees with commenters that the second round of testing is unnecessary to substantiate the AEDM and is proposing to eliminate the second round of testing for commercial HVAC and water heaters.

4. Standardized Substantiation Package

Establishing a standardized substantiation package would provide a number of benefits, including predictability and consistency with respect to the submission and review of AEDM-related records. Under today's proposal, manufacturers would know what materials to maintain regarding the AEDM-based certifications of their products and DOE would be able to more readily discern the validity and completeness of these submissions.

Adopting a standardized substantiation package approach would provide a number of benefits. First, this approach would clearly inform manufacturers regarding the underlying materials they need to maintain in support of their certified ratings for each basic model that has been certified and rated using an AEDM. With this clarification, manufacturer confusion regarding document retention issues would be eliminated. Second, information packages submitted in response to a request under 10 CFR 429.71 would be comparable in content and lend themselves more readily to DOE's review of those technical materials supporting a given manufacturer's AEDM. By creating an approach that involves the submission of a standardized set of materials, which would likely include a summary of the basic models used to substantiate the AEDM, DOE anticipates that the review time of this material will be substantially less than if a non-standardized approach were used. Other information that would likely be part of this package includes, but is not limited to the following: information demonstrating that the substantiation criteria are met; supporting test data from physical tests of those basic models; information related to the AEDM such as its version number and applicable product classes; and a list of all the basic models that have been rated with the AEDM. DOE intends to address this topic further in the upcoming Certification, Compliance and Enforcement rulemaking.

D. DOE Validation

1. Evaluation

Under the current process, manufacturers must retain documentation containing a description of the AEDM, supporting test data, and the AEDM itself. To avail themselves of the less burdensome option of using an AEDM, manufacturers must be willing to run additional simulations, provide further analysis of previous AEDM output, and test selected basic models on request. See, e.g., 10 CFR 431.17 (specifying AEDM-related requirements for electric motors) and 10 CFR 429.70(c)(3) (specifying AEDM-related requirements for commercial HVAC–WH). However, DOE does not currently require a specific frequency for validating a given AEDM—e.g., annually or once every five years. To address this shortcoming, DOE sought comment in the RFI on how often it should, if at all, validate AEDMs without creating an undue burden on manufacturers or limiting the number of products in the marketplace.

AHRI stated that there was no need for DOE to validate AEDMs or ARMs, particularly if a manufacturer participates in a voluntary industry certification program (VICP). Carrier, Zero Zone, NEMA, Mitsubishi, and Goodman supported this view. (AHRI, No. 17.1 at p. 4; Carrier, No 7.1 at p. 6; Zero Zone, No. 18.1 at p. 12; Mitsubishi, No. 19.1 at p. 3–4; Goodman, No. 2.1 at p. 2) Structural Concepts asserted that the initial validation of AEDMs is all that is needed to ensure the accuracy of the AEDM, while Modine and Lennox argued that validation is unnecessary. (Structural Concepts, No. 26.1 at p. 3; Modine, No. 8.1 at p. 3; Lennox, No. 16.1 at p. 4) While NEMA also indicated that validation was unnecessary, it noted that if DOE still chooses to validate AEDMs, it should be done at most annually. (NEMA, No. 22.1 at p. 4) Traulsen suggested the same validation frequency (i.e., annually) as NEMA. (Traulsen, No. 9.1 at p. 4) Bradford White supported validation testing every three to five years and Hussmann favored testing at least 4 models annually—but at DOE's expense. (Bradford White, No. 5.1 at p. 2; Hussmann, No. 10.1 at p. 3)

In DOE's view, an AEDM validation measure is a necessary component of ensuring the accuracy of product ratings based on AEDMs. However, DOE recognizes that too frequent validation could be unnecessary. Accordingly, rather than specify a particular validation frequency requirement, DOE is reserving the right to request the documentation supporting the AEDM and to test a basic model at any point, pursuant to 10 CFR 429.104.

2. Assessment Testing

As part of today's notice, DOE also seeks to clarify how it would conduct assessment testing to evaluate whether basic models rated with the use of an AEDM comply with conservation standards. When conducting assessment testing, DOE will exercise its authority to select and test a single unit of a basic model, including those that have been certified using an AEDM, at any point, pursuant to 10 CFR 429.104. The unit will be tested to the applicable DOE test procedure at an independent, third-party laboratory accredited to the International Organization for Standardization (ISO)/International Electrotechnical Commission (IEC), ''General requirements for the competence of testing and calibration laboratories,'' ISO/IEC 17025:2005(E). The test results obtained from the testing of one unit will be compared to both the applicable Federal conservation standard as well as the manufacturer's certified rating, which was developed using an AEDM. If the test result indicates that the product was rated incorrectly, DOE may require the manufacturer to re-substantiate their AEDM using the DOE test data, and re-rate and re-certify the basic model, as may be necessary. If the test result indicates that the product may not meet Federal conservation standards, DOE may pursue enforcement testing pursuant to 10 CFR 429.110.

The following sections describe potential DOE actions in response to certain verification testing results.

a. Failure to Meet Certified Ratings

If testing results from DOE-initiated testing indicate that the model was rated incorrectly by an AEDM, DOE may require the manufacturer to re-substantiate their AEDM and re-rate and re-certify all products that were rated using the AEDM, as the new results from the AEDM prove necessary. DOE would make this determination by comparing the assessment test results to the certified rating to determine if the specified tolerances were maintained as prescribed in 10 CFR 429.70 (c). If a basic model is rated incorrectly, DOE proposes to require manufacturers to re-substantiate their AEDM within 30 days of being provided with test data by the Department. The manufacturer would be required to use the test data obtained through DOE testing in the re-substantiation of the AEDM. This would not require an entirely new set of testing by the manufacturer. However, if inclusion of test data from the Department results in new results for basic models that do not meet the substantiation criteria enumerated in 10 CFR 429.70 (c) (e.g., the specified tolerances), then a manufacturer must make additional modifications to the AEDM either through engineering modifications or additional testing. At this time, DOE has tentatively decided not to require new testing for basic models outside of the affected product class as part of the re-substantiation process, in order to alleviate manufacturer burden. Ultimately, if DOE requires re-substantiation of the AEDM, all basic models that were rated using the AEDM in question must be re-rated after re-substantiation and re-certified to the Department if re-substantiation resulted in a rating change for those models.

DOE requests comment on the appropriate course of action and necessary time to complete such steps when a basic model tested by DOE fails to meet its certified rating generated using an AEDM. (See Issue 6 under ''Issues on Which DOE Seeks Comment'' in section IV.B of this NOPR.)

b. Non-Compliance With Federal Standards

Based on the results of this initial assessment testing, DOE may initiate an investigation that a basic model may not comply with an applicable conservation standard pursuant to 10 CFR 429.106 and/or undertake enforcement testing pursuant to 10 CFR 429.110. If, following enforcement testing, a model is determined to be non-compliant, all other models within that basic model are deemed non-compliant. DOE will withhold a finding of noncompliance for all other basic models rated with the AEDM pending additional investigation.

If the basic model that is found non-compliant was used for substantiation of the AEDM, the manufacturer must re-substantiate that AEDM within 30 days of notification, pursuant to the substantiation requirements enumerated in 10 CFR 429.70(c). DOE is not proposing to require the manufacturer to re-test basic models that were tested previously for substantiation if DOE has not determined those models to be non-compliant.

c. Multiple Instances of Non-Compliance

Additionally, DOE is considering how to address those manufacturers whose AEDMs do not accurately rate their products on a recurring basis. One possible approach would be to restrict or disallow the use of AEDMs for these manufacturers. Under this approach, manufacturers would have an incentive to exercise greater care when developing and applying AEDMs to rate their products. Another option would be to impose civil penalties. DOE believes that manufacturers must be held accountable for the accuracy of their AEDMs and that a means of discouraging future attempts to circumvent the standards established either by Congress or DOE is necessary. However, DOE does not want to unduly burden manufacturers, adversely impact the ability of small businesses to compete, or otherwise impede the development and marketing of new and innovative compliant products for consumers to purchase.

Responding to DOE's RFI, numerous interested parties suggested a variety of steps DOE could take in dealing with an instance of non-compliance. AHRI observed that a finding of non-compliance does not necessarily indicate an error in the AEDM, and that all models should not be found non-compliant until the reason for failure has been determined. (AHRI, No. 17.1 at p. 3) Goodman, Lennox, Carrier, Modine, Hussmann, Heatcraft, First Company, PVI Industries, NEMA, and Structural Concepts all concurred with this comment. (Goodman, No. 2.1 at p. 1; Carrier, No. 7.1 at pp. 2–3; Modine, No. 8, at p. 1; Hussmann, No. 10.1 at p. 2; Heatcraft, No. 11.1 at p. 2; Lennox, No. 13.1 at p. 2; Lennox, No. 16.1 at p. 2; First Company; No. 14.1 at p. 2; PVI Industries, No. 15.1 at p. 3; NEMA, No. 22.1 at p. 2; Structural Concepts, No. 26.1 at p. 1). Zero Zone and NEMA noted that, rather than restrict AEDM usage, DOE should focus on finding the cause of the error and ensuring that a correction is made. (Zero Zone, No. 18.1 at p. 7; NEMA, No. 20.1 at p. 3)

However, some stakeholders recognized the need to more actively discourage manufacturers who are consistently non-compliant or intentionally non-compliant. Traulsen, Bradford White, First Company and EarthJustice all stated that DOE should disallow the use of AEDMs for manufacturers after multiple instances of non-compliance, while American Panel wrote that the use of AEDMs should be disallowed if there was willful intent by the manufacturer regarding the ratings from the AEDM. (American Panel, No. 3.1 at p. 2; Traulsen, No. 9.1 at p. 3; First Company, No. 14.1 at p. 2; EarthJustice, No. 21.1 at p. 1)

DOE concurs that finding the root cause of a non-compliance is important. As important as this factor is, DOE stresses that determining this cause is the manufacturer's responsibility, not DOE's. DOE remains concerned, however, that the prospect of disallowing the use of AEDMs following a single instance of non-compliance would place a significant burden on manufacturers, and the additional testing necessitated by this penalty potentially could lead to time-to-market delays. Therefore, DOE is proposing to disallow the use of an AEDM following multiple instances of non-compliance and/or if there is evidence that the mis-rating was willful.

DOE requests comment on the proposal that DOE disallow the use of an AEDM if there is evidence that the mis-rating is willful and/or there are multiple instances of non-compliance. (See Issue 7 under ''Issues on Which DOE Seeks Comment'' in section IV.B of this NOPR.)

2. Re-Substantiation

In addition to re-substantiation required by DOE as the result of assessment testing, DOE is concerned about the need to update an AEDM to avoid having AEDMs based on outdated substantiation data, which could lead to inaccurate ratings for basic models certified using AEDMs, and requested comment in the RFI on the necessity and required frequency of re-substantiation.

Carrier and Goodman asserted that a given manufacturer's familiarity and understanding of both its products and AEDMs makes them better equipped than DOE to decide when re-substantiation is necessary. (Carrier, No. 7.1 at p. 5; Goodman, No. 2.1 at p. 1) Goodman also noted that there would be an additional burden placed on manufacturers by mandatory re-substantiation, and several other stakeholders, including American Panel, Heatcraft, First Company, and Lennox voiced similar concerns about the added burden. (Goodman, No. 2.1 at p. 1; American Panel, No. 3.1 at p. 3; Heatcraft, No. 11.1 at p. 3; First Company, No. 14.1 at p. 2; Lennox, No. 16.1 at p. 3)

In contrast, a variety of stakeholders—American Panel, First Company, Lennox, NEMA and AHRI—all remarked that significant changes in a test method would justify re-substantiation. (American Panel, No. 3.1 at p. 3; First Company, No. 14.1 at p. 2; Lennox, No. 16.1 at p. 3; AHRI, No. 17.1 at p. 5; NEMA, No. 20.1 at p. 5). Several commenters, including Modine, Hussmann, Howe, Mitsubishi and Structural Concepts, disagreed with this opinion and believed that there is no need for re-substantiation. (Modine, No.

8.1 at p. 3; Hussmann, No. 10.1 at p. 3; Howe, No. 12.1 at p. 1; Mitsubishi, No. 19.1 at p. 3; Structural Concepts, No. 26.1 at p. 2) PVI Industries was the only stakeholder who suggested that re-substantiation be required after a specific amount of time, and it recommended that at least one sample be tested every five years to re-substantiate the AEDM. (PVI Industries, No. 15.1 at p. 5)

DOE is concerned that, without some type of re-substantiation requirement, AEDMs could become outdated over time if they are based on old models, which have been discontinued and are not currently in production. However, DOE acknowledges manufacturer concerns over the additional test burden and is not proposing to require re-substantiation on a periodic basis. Instead, DOE is proposing that manufacturers must re-substantiate their AEDMs when there is a change either to the applicable standards or DOE test procedure. Additionally, DOE is proposing that the substantiation data used by the manufacturer must be obtained from physical tests of current models from that manufacturer. DOE is taking this approach because it agrees with commenters who claim that it is not necessary to re-substantiate an AEDM for products for which there has been no change that would cause the model to behave differently under testing. However, changes to the applicable standards or DOE test procedure are more likely to necessitate changes to a given AEDM that would result in a different output. When a model used for substantiation of the AEDM is discontinued or becomes obsolete, a manufacturer will need to replace that model with a new model and re-rate or re-certify as necessary.

DOE requests comment on the necessity of requiring re-substantiation when there is a change in standards or test procedure and requiring that AEDMs be substantiated with active models. (See Issue 8 under ''Issues on Which DOE Seeks Comment'' in section IV.B of this NOPR.)

III. Procedural Issues and Regulatory Review

A. Review Under Executive Order 12866

The Office of Management and Budget has determined that test procedure rulemakings do not constitute ''significant regulatory actions'' under section 3(f) of Executive Order 12866, Regulatory Planning and Review, 58 FR 51735 (Oct. 4, 1993). Accordingly, this action was not subject to review under the Executive Order by the Office of Information and Regulatory Affairs (OIRA) in the Office of Management and Budget (OMB).

B. Review Under the Regulatory Flexibility Act

The Regulatory Flexibility Act (5 U.S.C. 601, et seq.) requires the preparation of an initial regulatory flexibility analysis (IRFA) for any rule that by law must be proposed for public comment, unless the agency certifies that the rule, if promulgated, will not have a significant economic impact on a substantial number of small entities. As required by Executive Order 13272, ''Proper Consideration of Small Entities in Agency Rulemaking,'' 67 FR 53461 (August 16, 2002), DOE published procedures and policies on February 19, 2003, to ensure that the potential impacts of its rules on small entities are properly considered during the DOE rulemaking process. 68 FR 7990. DOE has made its procedures and policies available on the Office of the General Counsel's Web site: *www.gc.doe.gov.* DOE reviewed the test procedures considered in today's NOPR under the provisions of the Regulatory Flexibility Act (RFA) and the policies and procedures published on February 19, 2003.

DOE reviewed the AEDM and ARM requirements being proposed under the provisions of the Regulatory Flexibility Act and the procedures and policies published on February 19, 2003. As discussed in more detail below, DOE found that because the provisions of this rule will not result in increased testing and/or reporting burden for manufacturers already eligible to use an AEDM and will extend AEDM use to a number of manufacturers, thus reducing their testing burden, manufacturers will not experience increased financial burden as a result of this rule.

Today's proposal, which presents voluntary methods for certifying compliance in lieu of conducting actual physical testing, would not increase the testing or reporting burden of manufacturers who currently use, or are eligible to use, an AEDM to certify their products. Manufacturers who produce products that may be certified using ARMs must obtain approval from the Department prior to the use of those ARMs for certification purposes. This rule, if promulgated, will eliminate the ARM nomenclature and treat these methods as AEDMs. As a result, the pre-approval requirement will be eliminated, resulting in a reduction in reporting burden for those manufacturers.

Furthermore, proposed requirements for substantiation of an AEDM do not require more testing than that required by the AEDM provisions included in the March 7, 2011 Certification, Compliance and Enforcement Final Rule (76 FR 12422) (''March 2011 Final Rule''), and would relax tolerances that tested products are required to meet in order to substantiate the AEDM. In this proposed rule, DOE has discussed re-substantiation requirements for manufacturers utilizing an AEDM. While these requirements were not directly stated in the March 2011 Final Rule, DOE believes that the March rule implicitly included requirements for re-substantiation within its AEDM requirements. DOE is explicitly including re-substantiation requirements in this proposed rule to provide clarity for those manufacturers using an AEDM. As such, DOE does not believe these requirements result in an increased burden for manufacturers who already use an AEDM.

Finally, DOE has clarified in today's proposal how it intends to exercise its authority to validate AEDM performance and verify the performance of products certified using an AEDM. This is a clarification of the process that DOE promulgated in the March 2011 Final Rule and would not increase burden for manufacturers currently allowed to use AEDMs to certify their products.

This notice also proposes to extend the applicability of AEDMs to products that are currently not permitted to be certified or rated by these alternate methods. Manufacturers not eligible to use AEDMs must currently test at least two units of every basic model that they produce in order to certify compliance to the Department pursuant to the March 2011 Final Rule. Today's proposal would reduce a manufacturer's testing burden by enabling these manufacturers to simulate testing based on testing data derived from a reduced number of units. While the Department believes that permitting greater use of AEDMs will reduce the affected manufacturer's test burden, their use is at the manufacturer's discretion. If, as a result of any of the proposals herein, a manufacturer believes that use of an AEDM would increase rather than decrease their financial burden, the manufacturer may choose not to employ the method. Should a manufacturer choose to abstain from using an AEDM, this proposed provision would not apply and the manufacturer would continue to remain subject to the requirements of any DOE test procedure that applies to that product, which would result in no change in burden from that which is required currently.

For the reasons enumerated above, DOE is certifying that the proposed rule, if promulgated, would not have a significant impact on a substantial number of small entities.

C. Review Under the Paperwork Reduction Act

Manufacturers of the covered products addressed in today's NOPR must certify to DOE that their equipment comply with any applicable energy conservation standards. In certifying compliance, manufacturers must test their equipment according to the applicable DOE test procedures for the given equipment type, including any amendments adopted for those test procedures, or use the AEDMs to develop the certified ratings of the basic models. DOE has established regulations for the certification and recordkeeping requirements for all covered consumer products and commercial equipment, including the equipment at issue in this NOPR. (76 FR 12422 (March 7, 2011)). The collection-of-information requirement for these certification and recordkeeping provisions is subject to review and approval by OMB under the Paperwork Reduction Act (PRA). This requirement has been approved by OMB under OMB control number 1910–1400. Public reporting burden for the certification is estimated to average 20 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information.

Notwithstanding any other provision of the law, no person is required to respond to, nor shall any person be subject to a penalty for failure to comply with, a collection of information subject to the requirements of the PRA, unless that collection of information displays a currently valid OMB Control Number.

D. Review Under the National Environmental Policy Act

DOE has determined that this rule falls into a class of actions that are categorically excluded from review under the National Environmental Policy Act of 1969 (42 U.S.C. 4321 et seq.) and DOE's implementing regulations at 10 CFR part 1021. Specifically, this proposed rule would adopt changes for certifying certain covered appliances, so it would not affect the amount, quality or distribution of energy usage, and, therefore, would not result in any environmental impacts. Thus, this rulemaking is covered by Categorical Exclusion A6 under 10 CFR part 1021, subpart D. Accordingly, neither an environmental assessment nor an environmental impact statement is required.

E. Review Under Executive Order 13132

Executive Order 13132, ''Federalism,'' 64 FR 43255 (August 4, 1999) imposes certain requirements on agencies formulating and implementing policies or regulations that preempt State law or that have Federalism implications. The Executive Order requires agencies to examine the constitutional and statutory authority supporting any action that would limit the policymaking discretion of the States and to carefully assess the necessity for such actions. The Executive Order also requires agencies to have an accountable process to ensure meaningful and timely input by State and local officials in the development of regulatory policies that have Federalism implications. On March 14, 2000, DOE published a statement of policy describing the intergovernmental consultation process it will follow in the development of such regulations. 65 FR 13735. DOE has examined this proposed rule and has determined that it 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. EPCA governs and prescribes Federal preemption of State regulations as to energy conservation for the products that are the subject of today's proposed rule. States can petition DOE for exemption from such preemption to the extent, and based on criteria, set forth in EPCA. (42 U.S.C. 6297(d)) No further action is required by Executive Order 13132.

F. Review Under Executive Order 12988

Regarding the review of existing regulations and the promulgation of new regulations, section 3(a) of Executive Order 12988, ''Civil Justice Reform,'' 61 FR 4729 (Feb. 7, 1996), imposes on Federal agencies the general duty to adhere to the following requirements: (1) Eliminate drafting errors and ambiguity; (2) write regulations to minimize litigation; (3) provide a clear legal standard for affected conduct rather than a general standard; and (4) promote simplification and burden reduction. Section 3(b) of Executive Order 12988 specifically requires that Executive agencies make every reasonable effort to ensure that the regulation: (1) Clearly specifies the preemptive effect, if any; (2) clearly specifies any effect on existing Federal law or regulation; (3) provides a clear legal standard for affected conduct while promoting simplification and burden reduction; (4) specifies the retroactive effect, if any; (5) adequately defines key terms; and (6) addresses other important issues affecting clarity and general draftsmanship under any guidelines issued by the Attorney General. Section 3(c) of Executive Order 12988 requires Executive agencies to review regulations in light of applicable standards in sections 3(a) and 3(b) to determine whether they are met or it is unreasonable to meet one or more of them. DOE has completed the required review and determined that, to the extent permitted by law, the proposed rule meets the relevant standards of Executive Order 12988.

G. Review Under the Unfunded Mandates Reform Act of 1995

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA) requires each Federal agency to assess the effects of Federal regulatory actions on State, local, and Tribal governments and the private sector. Public Law 104–4, sec. 201 (codified at 2 U.S.C. 1531). For a proposed regulatory action likely to result in a rule that may cause the expenditure by State, local, and Tribal governments, in the aggregate, or by the private sector of $100 million or more in any one year (adjusted annually for inflation), section 202 of UMRA requires a Federal agency to publish a written statement that estimates the resulting costs, benefits, and other effects on the national economy. (2 U.S.C. 1532(a), (b)) The UMRA also requires a Federal agency to develop an effective process to permit timely input by elected officers of State, local, and Tribal governments on a proposed ''significant intergovernmental mandate,'' and requires an agency plan for giving notice and opportunity for timely input to potentially affected small governments before establishing any requirements that might significantly or uniquely affect small governments. On March 18, 1997, DOE published a statement of policy on its process for intergovernmental consultation under UMRA. 62 FR 12820; also available at *www.gc.doe.gov.* DOE examined today's proposed rule according to UMRA and its statement of policy and determined that the rule contains neither an intergovernmental mandate, nor a mandate that may result in the expenditure of $100 million or more in any year, so these requirements do not apply.

H. Review Under the Treasury and General Government Appropriations Act, 1999

Section 654 of the Treasury and General Government Appropriations

Act, 1999 (Pub. L. 105–277) requires Federal agencies to issue a Family Policymaking Assessment for any rule that may affect family well-being. This rule would not have any impact on the autonomy or integrity of the family as an institution. Accordingly, DOE has concluded that it is not necessary to prepare a Family Policymaking Assessment.

I. Review Under Executive Order 12630

DOE has determined, under Executive Order 12630, ''Governmental Actions and Interference with Constitutionally Protected Property Rights'' 53 FR 8859 (March 18, 1988), that this regulation would not result in any takings that might require compensation under the Fifth Amendment to the U.S. Constitution.

J. Review Under the Treasury and General Government Appropriations Act, 2001

Section 515 of the Treasury and General Government Appropriations Act, 2001 (44 U.S.C. 3516 note) provides for agencies to review most disseminations of information to the public under guidelines established by each agency pursuant to general guidelines issued by OMB. OMB's guidelines were published at 67 FR 8452 (Feb. 22, 2002), and DOE's guidelines were published at 67 FR 62446 (Oct. 7, 2002). DOE has reviewed today's proposed rule under the OMB and DOE guidelines and has concluded that it is consistent with applicable policies in those guidelines.

K. Review Under Executive Order 13211

Executive Order 13211, ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use,'' 66 FR 28355 (May 22, 2001), requires Federal agencies to prepare and submit to OMB, a Statement of Energy Effects for any proposed significant energy action. A ''significant energy action'' is defined as any action by an agency that promulgated or is expected to lead to promulgation of a final rule, and that: (1) Is a significant regulatory action under Executive Order 12866, or any successor order; and (2) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (3) is designated by the Administrator of OIRA as a significant energy action. For any proposed significant energy action, the agency must give a detailed statement of any adverse effects on energy supply, distribution, or use should the proposal be implemented, and of reasonable alternatives to the action and their expected benefits on energy supply, distribution, and use.

Today's regulatory action to establish alternate certification requirements for certain covered appliances is not a significant regulatory action under Executive Order 12866. Moreover, it would not have a significant adverse effect on the supply, distribution, or use of energy, nor has it been designated as a significant energy action by the Administrator of OIRA. Therefore, it is not a significant energy action, and, accordingly, DOE has not prepared a Statement of Energy Effects.

IV. Public Participation

A. Submission of Comments

DOE will accept comments, data, and information regarding the proposed rule no later than the date provided at the beginning of this notice. Comments, data, and information submitted to DOE's email address for this rulemaking should be provided in WordPerfect, Microsoft Word, PDF, or text (ASCII) file format. Interested parties should avoid the use of special characters or any form of encryption, and wherever possible, comments should include the electronic signature of the author. Absent an electronic signature, comments submitted electronically must be followed and authenticated by submitting a signed original paper document to the address provided at the beginning of this notice. Comments, data, and information submitted to DOE via mail or hand delivery/courier should include one signed original paper copy. No telefacsimiles (faxes) will be accepted.

According to 10 CFR 1004.11, any person submitting information that he or she believes to be confidential and exempt by law from public disclosure should submit two copies: one copy of the document including all the information believed to be confidential and one copy of the document with the information believed to be confidential deleted. DOE will make its own determination as to the confidential status of the information and treat it according to its determination.

Factors of interest to DOE when evaluating requests to treat submitted information as confidential include (1) a description of the items, (2) whether and why such items are customarily treated as confidential within the industry, (3) whether the information is generally known by or available from other sources, (4) whether the information has previously been made available to others without obligation concerning its confidentiality, (5) an explanation of the competitive injury to the submitting person which would result from public disclosure, (6) a date upon which such information might lose its confidential nature due to the passage of time, and (7) why disclosure of the information would be contrary to the public interest.

B. Issues on Which DOE Seeks Comment

Although DOE welcomes comments on any aspect of this proposal, DOE is particularly interested in receiving comments and views of interested parties concerning the following issues:

1. DOE requests comment on its proposal not to add a pre-approval process for AEDMs and its proposal to no longer require pre-approval for use of an alternative rating method for residential central air conditioners and heat pumps.

2. DOE requests comment on its proposal to expand the use of AEDMs to other commercial products.

3. DOE requests comment on its proposal to require at least one basic model from each product class to be tested to substantiate the AEDM. Specifically, DOE requests comments from manufacturers as to whether additional clarification is needed for manufacturers of certain covered products to determine all the applicable product classes that would need to be tested to substantiate the AEDM. As part of these comments, the Department is interested in receiving feedback on how manufacturers currently develop any simulation tools to ensure they are applicable across a wide range of product classes.

4. DOE seeks product specific comments on proposed overall and individual tolerance levels by product type. Specifically, DOE seeks data which show that the variability seen in the manufacturing processes, test instrumentation, and testing procedures are such that a different tolerance should be considered.

5. DOE seeks comment on the criteria for selection of basic models and the number of basic models a manufacturer should be required to test for substantiation as well as whether the differences in testing requirements for distribution transformers are appropriate or necessary.

6. DOE seeks comment on the appropriate course of action and the time to complete such steps when a model tested by DOE fails to meet its certified rating.

7. DOE requests comment on the proposal to disallow the use of an AEDM if there is evidence that the mis-rating is willful and/or there are multiple instances of non-compliance.

8. DOE requests comment on the necessity of requiring re-substantiation when there is a change in standards or test procedure and requiring that AEDMs be re-substantiated with active models.

V. Approval of the Office of the Secretary

The Secretary of Energy has approved publication of today's NOPR.

List of Subjects

10 CFR Part 429

Administrative practice and procedure, Confidential business information, Energy conservation, Reporting and recordkeeping requirements.

10 CFR Part 430

Administrative practice and procedure, Confidential business information, Energy conservation, Household appliances, Imports, Intergovernmental relations, and Small businesses.

10 CFR Part 431

Administrative practice and procedure, Confidential business information, Energy conservation, Reporting and recordkeeping requirements.

Issued in Washington, DC, on May 24, 2012.

Timothy Unruh,

Acting Deputy Assistant Secretary, Energy Efficiency and Renewable Energy.

For the reasons set forth in the preamble, DOE proposes to amend parts 429, 430 and 431 of chapter II, subchapter D, of title 10 of the Code of Federal Regulations, as set forth below:

PART 429—CERTIFICATION, COMPLIANCE AND ENFORCEMENT FOR CONSUMER PRODUCTS AND COMMERCIAL AND INDUSTRIAL EQUIPMENT

1. The authority citation for part 429 continues to read as follows:

Authority: 42 U.S.C. 6291–6317.

2. Section 429.1 is revised to read as follows:

§ 429.1 Purpose and scope.

This part sets forth the procedures to be followed for certification, determination and enforcement of compliance of covered products and covered equipment with the applicable conservation standards set forth in parts 430 and 431 of this subchapter.

3. Section 429.2 is amended by adding the definition for " Alternative Efficiency Determination Method or AEDM'' in alphabetical order to paragraph (b) to read as follows:

§ 429.2 Definitions.

* * * * *

Alternative Efficiency Determination Method or AEDM is a simulation, calculation or engineering algorithm for determining the efficiency or consumption of a basic model of consumer product or commercial equipment, in terms of the appropriate descriptor used in or under section 325 or 342(a) of the Act to state the standard for that product.

* * * * *

4. Section 429.12 is amended by revising paragraph (b)(12) to read as follows:

§ 429.12 General requirements applicable to certification reports.

* * * * *

(b) * * *

(12) Whether certification is based upon the use of an AEDM, where permitted, for determining measures of energy conservation and the name or version of any such AEDM; and

* * * * *

5. Section 429.16 is amended by revising paragraph (a) and removing paragraph (c) to read as follows:

§ 429.16 Central air conditioners and heat pumps.

(a) *Determination of Certified Rating.* Manufacturers can determine the certified rating for each basic model either by testing or by applying a substantiated AEDM in conjunction with the applicable sampling procedures.

(1) *Units to be tested.*

(i) If represented values are determined through testing, the general requirements of § 429.11 are applicable to central air conditioners and heat pumps; and

(ii)(A) For central air conditioners and heat pumps, each single-package system and each condensing unit (outdoor unit) of a split-system, when combined with a selected evaporator coil (indoor unit) or a set of selected indoor units, must have a sample of sufficient size tested in accordance with the applicable provisions of this subpart. The represented values for any model of a single-package system, any model of a tested split-system combination, any model of a tested mini-split system combination, or any model of a tested multi-split system combination must be assigned such that—

(*1*) Any represented value of annual operating cost, energy consumption or other measure of energy consumption of the central air conditioner or heat pump for which consumers would favor lower values shall be greater than or equal to the higher of:

(*i*) The mean of the sample, where:

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} x_i$$

and, $\bar{x}$ is the sample mean; n is the number of samples; and x_i is the i^{th} sample;

Or,

(*ii*) The upper 90 percent confidence limit (UCL) of the true mean divided by 1.05, where:

$$UCL = \bar{x} + t_{.90}\left(\frac{s}{\sqrt{n}}\right)$$

And $\bar{x}$ is the sample mean; s is the sample standard deviation; n is the number of samples; and $t_{0.90}$ is the t statistic for a 90% one-tailed confidence interval with n − 1 degrees of freedom (from Appendix D).

and

(*2*) Any represented value of the energy efficiency or other measure of energy consumption of the central air conditioner or heat pump for which consumers would favor higher values shall be less than or equal to the lower of:

(*i*) The mean of the sample, where:

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} x_i$$

and, $\bar{x}$ is the sample mean; n is the number of samples; and x_i is the i^{th} sample;

Or,

(*ii*) The lower 90 percent confidence limit (LCL) of the true mean divided by 0.95, where:

$$LCL = \bar{x} - t_{.90}\left(\frac{s}{\sqrt{n}}\right)$$

And $\bar{x}$ is the sample mean; s is the sample standard deviation; n is the number of samples; and $t_{0.90}$ is the t statistic for a 90% one-tailed confidence interval with n − 1 degrees of freedom (from Appendix D).

(B) For heat pumps, all units of the sample population must be tested in both the cooling and heating modes and the results used for determining the heat pump's certified Seasonal Energy Efficiency Ratio (SEER) and Heating Seasonal Performance Factor (HSPF) ratings in accordance with paragraph (a)(1)(ii)(A)(*2*) of this section.

(C) For split-system air conditioners and heat pumps, the condenser-evaporator coil combination selected for tests pursuant to paragraph (a)(1)(ii)(A) of this section shall include the evaporator coil that is likely to have the largest volume of retail sales with the particular model of condensing unit. For mini-split condensing units that are designed to always be installed with more than one indoor unit, a ''tested combination'' as defined in 10 CFR 430.2 shall be used for tests pursuant to paragraph (a)(1)(ii)(A) of this section. For multi-split systems, each model of condensing unit shall be tested with two different sets of indoor units. For one set, a ''tested combination'' composed entirely of non-ducted indoor units shall be used. For the second set, a ''tested combination'' composed entirely of ducted indoor units shall be used. However, for any split-system air conditioner having a single-speed compressor, the condenser-evaporator coil combination selected for tests pursuant to paragraph (a)(1)(ii)(A) of this section shall include the indoor coil-only unit that is likely to have the largest volume of retail sales with the particular model of outdoor unit. This coil-only requirement does not apply to split-system air conditioners that are only sold and installed with blower-coil indoor units, specifically mini-splits, multi-splits, and through-the-wall units. This coil-only requirement does not apply to any split-system heat pumps. For every other split-system combination that includes the same model of condensing unit but a different model of evaporator coil and for every other mini-split and multi-split system that includes the same model of condensing unit but a different set of evaporator coils, whether the evaporator coil(s) is manufactured by the same manufacturer or by a component manufacturer, either—

(*1*) A sample of sufficient size, comprised of production units or representing production units, must be tested as complete systems with the resulting ratings for the outdoor unit-indoor unit(s) combination obtained in accordance with paragraphs (a)(1)(ii)(A)(*1*) and (a)(1)(ii)(A)(*2*) of this section; or

(*2*) The representative values of the measures of energy efficiency must be assigned as follows:

(*i*) For multi-split systems composed entirely of non-ducted indoor units, set equal to the system tested in accordance with paragraph (a)(1)(ii)(A) of this section whose tested combination was entirely non-ducted indoor units; or

(*ii*) For multi-split systems composed entirely of ducted indoor units, set equal to the system tested in accordance with paragraph (a)(1)(ii)(A) of this section when the tested combination was entirely ducted indoor units; or

(*iii*) For multi-split systems having a mix of non-ducted and ducted indoor units, set equal to the mean of the values for the two systems—one having the tested combination of all non-ducted units and the second having the tested combination of all ducted indoor units—tested in accordance with paragraph (a)(1)(ii)(A) of this section.

(2) *Alternative efficiency determination methods.* In lieu of testing, represented values of efficiency or consumption of central air conditioners and heat pumps may be certified as based on a single unit when determined through the application of an AEDM pursuant to the requirements of § 429.70 and the provisions of this section, where:

(i) Any represented value of estimated maximum daily energy consumption or other measure of energy consumption of a basic model for which consumers would favor lower values shall be greater than or equal to the output of the AEDM; and

(ii) Any represented value of the energy efficiency or other measure of energy consumption of a basic model for which consumers would favor higher values shall be less than or equal to the output of the AEDM.

* * * * *

6. Section 429.42 is amended by revising paragraph (a) to read as follows:

§ 429.42 Commercial refrigerators, freezers, and refrigerator-freezers.

(a) *Determination of Certified Rating.* Manufacturers can determine the certified rating for each basic model either by testing or by applying a substantiated AEDM in conjunction with the applicable sampling procedures.

(1) Units to be tested.

(i) If represented values are determined through testing, the general requirements of § 429.11 are applicable to commercial refrigeration equipment; and

(ii)(A) For each basic model of commercial refrigerator, freezer, or refrigerator-freezer selected for testing, a sample of sufficient size shall be randomly selected and tested to ensure that—to ensure that—

(*1*) Any represented value of estimated maximum daily energy consumption or other measure of energy consumption of a basic model for which consumers would favor lower values shall be greater than or equal to the higher of:

(*i*) The mean of the sample, where:

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} x_i$$

and, $\bar{x}$ is the sample mean; n is the number of samples; and x_i is the i^{th} sample;

Or,

(*ii*) The upper 95 percent confidence limit (UCL) of the true mean divided by 1.10, where:

$$UCL = \bar{x} + t_{.95}\left(\frac{s}{\sqrt{n}}\right)$$

And $\bar{x}$ is the sample mean; s is the sample standard deviation; n is the number of samples; and $t_{0.95}$ is the t statistic for a 95% one-tailed confidence interval with n − 1 degrees of freedom (from Appendix D).

and

(*2*) Any represented value of the energy efficiency or other measure of energy consumption of a basic model for which consumers would favor higher values shall be less than or equal to the lower of:

(*i*) The mean of the sample, where:

$$\bar{\mathbf{x}} = \frac{1}{n}\sum_{i=1}^{n} \mathbf{x}_i$$

and, $\bar{x}$ is the sample mean; n is the number of samples; and x_i is the i^{th} sample;

Or,

(*ii*) The lower 95 percent confidence limit (LCL) of the true mean divided by 0.90, where:

$$LCL = \bar{x} - t_{.95}\left(\frac{s}{\sqrt{n}}\right)$$

And $\bar{x}$ is the sample mean; s is the sample standard deviation; n is the number of samples; and $t_{0.95}$ is the t statistic for a 95% one-tailed confidence interval with n − 1 degrees of freedom (from Appendix D).

(2) *Alternative efficiency determination methods.* In lieu of testing, represented values of efficiency or consumption of commercial refrigerators, freezers or refrigerator-freezers may be certified as based on a single unit when determined through the application of an AEDM pursuant to the requirements of § 429.70 and the provisions of this section, where:

(i) Any represented value of estimated maximum daily energy consumption or other measure of energy consumption of a basic model for which consumers would favor lower values shall be greater than or equal to the output of the AEDM; and

(ii) Any represented value of the energy efficiency or other measure of energy consumption of a basic model for which consumers would favor higher values shall be less than or equal to the output of the AEDM.

* * * * *

7. Section 429.43 is amended by revising paragraph (a) and removing paragraph (c) to read as follows:

§ 429.43 Commercial heating, ventilating, air conditioning (HVAC) equipment.

(a) *Determination of Certified Rating.* Manufacturers can determine the certified rating for each basic model either by testing or by applying a substantiated AEDM in conjunction with the applicable sampling procedures.

(1) *Units to be tested.*

(i) If represented values are determined through testing, the general requirements of § 429.11 are applicable to commercial HVAC equipment; and

(ii)(A) For each basic model of commercial HVAC equipment, a sample of sufficient size shall be selected and tested to ensure that—

(*1*) Any represented value of energy consumption or other measure of energy usage of a basic model for which consumers would favor lower values shall be greater than or equal to the higher of:

(*i*) The mean of the sample, where:

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} x_i$$

and, $\bar{x}$ is the sample mean; n is the number of samples; and x_i is the i^{th} sample;

Or,

(*ii*) The upper 95 percent confidence limit (UCL) of the true mean divided by 1.05, where:

$$UCL = \bar{x} + t_{.95}\left(\frac{s}{\sqrt{n}}\right)$$

And $\bar{x}$ is the sample mean; s is the sample standard deviation; n is the number of samples; and $t_{0.95}$ is the t statistic for a 95% one-tailed confidence interval with n − 1 degrees of freedom (from Appendix D).

and

(*2*) Any represented value of energy efficiency or other measure of energy consumption of a basic model for which consumers would favor higher values shall be less than or equal to the lower of:

(*i*) The mean of the sample, where:

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} x_i$$

and, $\bar{x}$ is the sample mean; n is the number of samples; and x_i is the i^{th} sample;

Or,

(*ii*) The lower 95 percent confidence limit (LCL) of the true mean divided by 0.95, where:

$$LCL = \bar{x} - t_{.95}\left(\frac{s}{\sqrt{n}}\right)$$

And $\bar{x}$ is the sample mean; s is the sample standard deviation; n is the number of samples; and $t_{0.95}$ is the t statistic for a 95% one-tailed confidence interval with n − 1 degrees of freedom (from Appendix D).

(2) *Alternative efficiency determination methods.* In lieu of testing, represented values of efficiency or consumption of commercial HVAC equipment may be certified as based on a single unit when determined through the application of an AEDM pursuant to the requirements of § 429.70 and the provisions of this section, where:

(i) Any represented value of energy consumption or other measure of energy usage of a basic model for which consumers would favor lower values shall be greater than or equal to the output of the AEDM; and

(ii) Any represented value of energy efficiency or other measure of energy consumption of a basic model for which consumers would favor higher values shall be less than or equal to the output of the AEDM.

* * * * *

8. Section 429.44 is amended by revising paragraph (a) and removing paragraph (c) to read as follows:

§ 429.44 Commercial water heating equipment.

(a) *Determination of Certified Rating.* Manufacturers can determine the certified rating for each basic model either by testing or by applying a substantiated AEDM in conjunction with the applicable sampling procedures.

(1) *Units to be tested.*

(i) If represented values are determined through testing, the general requirements of § 429.11 are applicable to commercial WH equipment; and

(ii)(A) For each basic model of commercial WH equipment, a sample of sufficient size shall be selected and tested to ensure that—

(*1*) Any represented value of maximum standby loss or other measure of energy usage of a basic model for which consumers would favor lower values shall be greater than or equal to the higher of:

(*i*) The mean of the sample, where:

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} x_i$$

and, $\bar{x}$ is the sample mean; n is the number of samples; and x_i is the i^{th} sample;

Or,

(*ii*) The upper 95 percent confidence limit (UCL) of the true mean divided by 1.05, where:

$$UCL = \bar{x} + t_{.95}\left(\frac{s}{\sqrt{n}}\right)$$

And $\bar{x}$ is the sample mean; s is the sample standard deviation; n is the number of samples; and $t_{0.95}$ is the t statistic for a 95% one-tailed confidence interval with n−1 degrees of freedom (from Appendix D).

and

(*2*) Any represented value of minimum thermal efficiency or other measure of energy consumption of a basic model for which consumers would favor higher values shall be less than or equal to the lower of:

(*i*) The mean of the sample, where:

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} x_i$$

and, $\bar{x}$ is the sample mean; n is the number of samples; and x_i is the i^{th} sample;

Or,

(ii) The lower 95 percent confidence limit (LCL) of the true mean divided by 0.95, where:

$$LCL = \bar{x} - t_{.95}\left(\frac{s}{\sqrt{n}}\right)$$

And $\bar{x}$ is the sample mean; s is the sample standard deviation; n is the number of samples; and $t_{0.95}$ is the t statistic for a 95% one-tailed confidence interval with n−1 degrees of freedom (from Appendix D).

(2) *Alternative efficiency determination methods.* In lieu of testing, represented values of efficiency or consumption of commercial WHWH equipment may be certified as based on a single unit when determined through the application of an AEDM pursuant to the requirements of § 429.70 and the provisions of this section, where:

(i) Any represented value of maximum standby loss or other measure of energy usage of a basic model for which consumers would favor lower values shall be greater than or equal to the output of the AEDM; and

(ii) Any represented value of minimum thermal efficiency or other measure of energy consumption of a basic model for which consumers would favor higher values shall be less than or equal to the output of the AEDM.

* * * * *

9. Section 429.45 is amended by revising paragraph (a) to read as follows:

§ 429.45 Automatic commercial ice makers.

(a) *Determination of Certified Rating.* Manufacturers can determine the certified rating for each basic model either by testing or by applying a substantiated AEDM in conjunction with the applicable sampling procedures.

(1) *Units to be tested.*

(i) If represented values are determined through testing, the general requirements of § 429.11 are applicable to automatic commercial ice makers; and

(ii)(A) For each basic model of automatic commercial ice maker selected for testing, a sample of sufficient size shall be randomly selected and tested to ensure that—

(*1*) Any represented value of maximum energy use or other measure of energy consumption of a basic model for which consumers would favor lower values shall be greater than or equal to the higher of:

(*i*) The mean of the sample, where:

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} x_i$$

and, $\bar{x}$ is the sample mean; n is the number of samples; and x_i is the i^{th} sample;

Or,

(*ii*) The upper 95 percent confidence limit (UCL) of the true mean divided by 1.10, where:

$$UCL = \bar{x} + t_{.95}\left(\frac{s}{\sqrt{n}}\right)$$

And $\bar{x}$ is the sample mean; s is the sample standard deviation; n is the number of samples; and $t_{0.95}$ is the t statistic for a 95% one-tailed confidence interval with n − 1 degrees of freedom (from Appendix D).

and

(*2*) Any represented value of the energy efficiency or other measure of energy consumption of a basic model for which consumers would favor higher values shall be less than or equal to the lower of:

(*i*) The mean of the sample, where:

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} x_i$$

and, $\bar{x}$ is the sample mean; n is the number of samples; and x_i is the i^{th} sample;

Or,

(*ii*) The lower 95 percent confidence limit (LCL) of the true mean divided by 0.90, where:

$$LCL = \bar{x} - t_{.95}\left(\frac{s}{\sqrt{n}}\right)$$

And $\bar{x}$ is the sample mean; s is the sample standard deviation; n is the number of samples; and $t_{0.95}$ is the t statistic for a 95% one-tailed confidence interval with n − 1 degrees of freedom (from Appendix D).

(2) *Alternative efficiency determination methods.* In lieu of testing, represented values of efficiency or consumption of automatic commercial ice makers may be certified as based on a single unit when determined through the application of an AEDM pursuant to the requirements of § 429.70 and the provisions of this section, where:

(i) Any represented value of maximum energy use or other measure of energy consumption of a basic model for which consumers would favor lower values shall be greater than or equal to the output of the AEDM; and

(ii) Any represented value of the energy efficiency or other measure of energy consumption of a basic model for which consumers would favor higher values shall be less than or equal to the output of the AEDM.

* * * * *

10. Section 429.47 is amended by revising paragraph (a) and removing paragraph (c) to read as follows:

§ 429.47 Distribution transformers.

(a) *Determination of Certified Rating.* Manufacturers can determine the certified rating for each basic model either by testing or by applying a substantiated AEDM in conjunction with the applicable sampling procedures.

(1) *Units to be tested.*

(i) If represented values are determined through testing, the general requirements of § 429.11 are applicable to distribution transformers; and

(ii)(A) For each basic model selected for testing:

(*1*) If the manufacturer produces five or fewer units of a basic model over 6 months, each unit must be tested. A manufacturer may not use a basic model with a sample size of fewer than five units to substantiate an AEDM pursuant to § 429.70.

(*2*) If the manufacturer produces more than five units over 6 months, a sample of at least five units must be selected and tested; and

(B) Any represented value of efficiency of a basic model must satisfy the condition:

$$RE \leq \frac{100}{1 + \left(\frac{100 - \bar{x}}{\bar{x}}\right)\left(\frac{\sqrt{n}}{\sqrt{n} + .08}\right)}$$

where $\bar{x}$ is the average efficiency of the sample.

(2) *Alternative efficiency determination methods.* In lieu of testing, represented values of efficiency of distribution transformers may be certified as based on a single unit when determined through the application of an AEDM pursuant to the requirements of § 429.70 and the provisions of this section, where any represented value of the energy efficiency or other measure of energy consumption of a basic model for which consumers would favor higher values shall be less than or equal to the output of the AEDM.

* * * * *

11. Section 429.52 is amended by revising paragraph (a) to read as follows:

§ 429.52 Refrigerated bottled or canned beverage vending machines.

(a) *Determination of Certified Rating.* Manufacturers can determine the certified rating for each basic model either by testing or by applying a substantiated AEDM in conjunction with the applicable sampling procedures.

(1) *Units to be tested.*

(i) If represented values are determined through testing, the general requirements of § 429.11 are applicable to refrigerated bottled or canned vending machines; and

(ii)(A) For each basic model of refrigerated bottled or canned beverage vending machine selected for testing, a sample of sufficient size shall be randomly selected and tested to ensure that—

(*1*) Any represented value of energy consumption or other measure of energy consumption of a basic model for which consumers would favor lower values shall be greater than or equal to the higher of:

(*i*) The mean of the sample, where:

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} x_i$$

and, $\bar{x}$ is the sample mean; n is the number of samples; and x_i is the i^{th} sample;

Or,

(*ii*) The upper 95 percent confidence limit (UCL) of the true mean divided by 1.10, where:

$$UCL = \bar{x} + t_{.95}\left(\frac{s}{\sqrt{n}}\right)$$

And $\bar{x}$ is the sample mean; s is the sample standard deviation; n is the number of samples; and $t_{0.95}$ is the t statistic for a 95% one-tailed confidence interval with n − 1 degrees of freedom (from Appendix D).

and

(*2*) Any represented value of the energy efficiency or other measure of energy consumption of a basic model for which consumers would favor higher values shall be less than or equal to the lower of:

(*i*) The mean of the sample, where:

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} x_i$$

and, $\bar{x}$ is the sample mean; n is the number of samples; and x_i is the i^{th} sample;

Or,

(*ii*) The lower 95 percent confidence limit (LCL) of the true mean divided by 0.90, where:

$$LCL = \bar{x} - t_{.95}\left(\frac{s}{\sqrt{n}}\right)$$

And $\bar{x}$ is the sample mean; s is the sample standard deviation; n is the number of samples; and $t_{0.95}$ is the t statistic for a 95% one-tailed confidence interval with n − 1 degrees of freedom (from Appendix D).

(2) *Alternative efficiency determination methods.* In lieu of testing, represented values of efficiency or consumption of refrigerated bottled or canned vending machines may be certified as based on a single unit when determined through the application of an AEDM pursuant to the requirements of § 429.70 and the provisions of this section, where:

(i) Any represented value of energy consumption or other measure of energy consumption of a basic model for which consumers would favor lower values shall be greater than or equal to the output of the AEDM; and

(ii) Any represented value of the energy efficiency or other measure of energy consumption of a basic model for which consumers would favor higher values shall be less than or equal to the output of the AEDM.

* * * * *

12. Section 429.53 is amended by revising paragraph (a) to read as follows:

§ 429.53 Walk-in coolers and walk-in freezers.

(a) *Determination of Certified Rating.* Manufacturers can determine the certified rating for each basic model either by testing or by applying a substantiated AEDM in conjunction with the applicable sampling procedures.

(1) *Units to be tested.*

(i) If represented values are determined through testing, the general requirements of § 429.11 are applicable to walk-in cooler or freezer refrigeration systems; and

(ii)(A) For each basic model of walk-in cooler or freezer refrigeration system selected for testing, a sample of sufficient size shall be randomly selected and tested to ensure that—

(*1*) Any represented value of energy consumption or other measure of energy consumption of a basic model for which consumers would favor lower values shall be greater than or equal to:

(*i*) The mean of the sample, where:

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} x_i$$

and, $\bar{x}$ is the sample mean; n is the number of samples; and x_i is the i^{th} sample;

Or,

(*ii*) Reserved. and

(*2*) Any represented value of the energy efficiency or other measure of energy consumption of a basic model for which consumers would favor higher values shall be less than or equal to:

(*i*) The mean of the sample, where:

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} x_i$$

and, $\bar{x}$ is the sample mean; n is the number of samples; and x_i is the i^{th} sample;

Or,

(*ii*) Reserved.

(2) *Alternative efficiency determination methods.* In lieu of testing, represented values of efficiency or consumption of walk-in cooler or freezer refrigeration systems may be certified as based on a single unit when determined through the application of an AEDM pursuant to the requirements of § 429.70 and the provisions of this section, where:

(i) Any represented value of energy consumption or other measure of energy consumption of a basic model for which consumers would favor lower values shall be greater than or equal to the output of the AEDM; and

(ii) Any represented value of the energy efficiency or other measure of energy consumption of a basic model for which consumers would favor higher values shall be less than or equal to the output of the AEDM.

* * * * *

13. Section 429.70 is amended by revising paragraphs (a), (c), (d) and (e) to read as follows:

§ 429.70 Alternative methods for determining energy efficiency and energy use.

(a) *General Applicability of an AEDM.* A manufacturer of commercial HVAC and WH equipment, distribution transformers, central air conditioners and heat pumps, commercial refrigeration equipment, refrigeration systems of walk-in coolers and freezers, automatic commercial ice makers, beverage vending machines, electric motors, and small electric motors may not distribute any basic model of such equipment in commerce unless the manufacturer has determined the energy efficiency of the basic model, either from testing the basic model or from applying an alternative method for determining energy efficiency or energy use (AEDM) to the basic model, in accordance with the requirements of this section. In instances where a manufacturer has tested a basic model to substantiate the alternative method, the energy efficiency of that basic model must be determined and rated according to results from actual testing and application of the sampling plans. In addition, a manufacturer may not knowingly use an AEDM to overrate the efficiency of a basic model. For each basic model of distribution transformer that has a configuration of windings that allows for more than one nominal rated voltage, the manufacturer must determine the basic model's efficiency either at the voltage at which the highest losses occur or at each voltage at which the transformer is rated to operate.

* * * * *

(c) *Substantiation of an AEDM.* Before using an AEDM, the manufacturer must substantiate the AEDM's accuracy and reliability as follows:

(1) Apply the AEDM to at least five of the manufacturer's basic models that have been selected for testing in accordance with paragraph (c)(5) of this section, and calculate the efficiency for each of these basic models. In any instance where a manufacturer has produced fewer than five basic models in the previous 6 months, select one model from each basic model and additional individual models to meet the minimum of five;

(2) Test at least one unit of each basic model to which the AEDM was applied in accordance with the applicable provisions of Part 430 or 431 and determine the efficiency (or consumption) for each of these basic models, except that, for distribution transformer AEDMs, test five units of each basic model selected for testing.

(3) *Individual Model Tolerances:*

(i) For electric motors and small electric motors, the efficiency predicted by the AEDM for each basic model must be within plus or minus 10 percent of the efficiency determined from the corresponding test of the basic model;

(ii) For all other products where an AEDM is authorized for use in paragraph (a) of this section, the efficiency predicted by the AEDM for each basic model must be within plus or minus 5 percent of the efficiency determined from the corresponding test of the basic model.

(4) *Averaged Tolerances:* The average of the predicted efficiencies of the five or more basic models determined in accordance with paragraph (c)(1) of this section must be within plus or minus 3 percent of the average of the tested efficiencies of the five or more basic models determined in accordance with paragraph (c)(2) of this section, where:

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} x_i$$

where $\bar{x}$ is the sample average efficiency, n is the number of samples and $\bar{x}_i$ is the efficiency of the i^{th} sample.

(5) *Additional Test Unit Requirements.*

(i) Each AEDM must be supported by test data obtained from physical tests of current models. The tested basic models underlying an AEDM must meet the following criteria:

(A) There must be at least one basic model selected from each DOE product class to which the AEDM will be applied;

(B) Two basic models must be from the product class with the highest sales volume. For residential AC/HP, Commercial HVAC, Commercial WH, ACIM, WICF refrigeration systems, CRE and BVMs; one of these two selected models must be the smallest capacity (*e.g.,* cooling capacity or total display area), and one must be within 25% of the largest capacity of the models to be covered by the AEDM;

(C) One tested model must be the basic model which either has the highest sales volume of the models covered by the AEDM during the prior year or is expected to have the highest sales volume in the coming year;

(D) Each selected model must meet the current applicable energy or water conservation standards for that product; and

(E) Each test must have been performed in accordance with the test procedure for which compliance is required at the time the basic model is distributed in commerce.

(ii) In any instance where it is not possible for a manufacturer to select basic models for testing in accordance with all of these criteria, the criteria shall be given priority in the order in which they are listed. Within the limits imposed by the criteria, basic models shall be selected randomly.

(d) AEDM Records and Procedures

(1) If a manufacturer has used an AEDM pursuant to this section;

(i) The manufacturer must have available for inspection by the Department records showing:

(A) The method or methods used;

(B) The mathematical model, the engineering or statistical analysis, computer simulation or modeling, and other analytic evaluation of performance data on which the AEDM is based;

(C) Complete test data, product information, and related information that the manufacturer generated or acquired through testing and AEDM calculations for each basic model; and

(D) The calculations used to determine the average efficiency, energy consumption, or power loss of each basic model to which an AEDM was applied.

(ii) If requested by the Department and at DOE's discretion, the manufacturer must perform at least one of the following:

(A) Conduct simulations before representatives of the Department to predict the performance of particular basic models of the product to which the AEDM was applied with DOE witnessing;

(B) Provide analyses of previous simulations conducted by the manufacturer; or

(C) Conduct certification testing of basic models selected by the Department.

(2) *Assessment Testing:* Pursuant to § 429.104, DOE may, at any time, test a basic model to assess whether the basic model is in compliance with the applicable energy conservation standards.

(i) *Indication of non-compliance:* Should the assessment testing suggest the basic model may not comply with the applicable energy conservation standards, DOE may initiate an investigation pursuant to § 429.106 and/or undertake enforcement testing pursuant to § 429.110;

(ii) *Finding of non-compliance:* The provisions of § 429.114 apply, and if the non-compliant basic model was used to substantiate the AEDM, within 30 days the manufacturer must:

(A) Re-substantiate the AEDM based on a completely new set of test data from the product class affected by the determination of non-compliance subject to the applicable provisions of Part 430 and 431, § 429.116, and paragraph (c) of this section, and

(B) Re-rate and re-certify, as necessary, with the re-substantiated AEDM, all basic models that were certified using the AEDM.

(iii) *Failure to meet certified ratings:* If DOE testing demonstrates that the basic model does not test within 10 percent of its certified rating for electric motors and small electric motors or within 5 percent of its certified rating for all other products, the manufacturer shall within 30 days of receipt of DOE test data;

(A) Re-substantiate the AEDM used to certify the model;

(*1*) Pursuant to paragraph (c) of this section, and

(*2*) Incorporate the DOE test data into the substantiation package for the AEDM and recalculate a certified rating for each basic models from the product class for which the tested model failed to achieve its rating. New test data is not required for models in unaffected product classes.

(B) Re-rate and re-certify with the updated AEDM, as necessary, all basic models that used the original AEDM.

(e) R*e-substantiation of an AEDM.*

(1) *Change in applicable standards or DOE test procedure:* Following a change in energy conservation or water use standards or DOE test procedure for products which are rated using an AEDM, a manufacturer shall re-substantiate the AEDM subject to the following criteria in addition to those listed in paragraph (c) of this section:

(i) The basic models used to substantiate the AEDM must be models currently in production; and

(ii) All test data used to substantiate the AEDM must meet the new standard levels.

(2) *Discontinuance of model on which substantiation of AEDM was based:* If a model that was used to substantiate the AEDM is discontinued, a manufacturer must replace that model's data and re-substantiate such that the AEDM is based on models currently in production and meets the criteria of paragraph (c).

(3) *Failure to re-substantiate an AEDM subject to these criteria:* If a manufacturer fails to re-substantiate an AEDM within 30 days of an occurrence of one of the events described in this section, then the AEDM becomes invalid and any certifications made pursuant to the AEDM are invalidated.

14. Section 429.116 is amended to read as follows:

§ 429.116 Additional certification testing requirements.

(a) If DOE determines that independent, third-party testing is necessary to ensure a manufacturer's compliance with the rules of this part, part 430, or part 431, a manufacturer must base its certification of a basic model under subpart B of this part on independent, third-party laboratory testing.

(b) If DOE determines that a manufacturer has used an AEDM to certify compliance and either has willfully certified the product at an unsupported rating or has distributed multiple, non-compliant basic models in commerce as a result of a faulty AEDM, DOE may prohibit continued use of an AEDM and require the manufacturer to base its certifications of compliance on physical testing of each basic model.

PART 430—ENERGY CONSERVATION PROGRAM FOR CONSUMER PRODUCTS

15. The authority citation for part 430 continues to read as follows:

Authority: 42 U.S.C. 6291–6309; 28 U.S.C. 2461 note.

§ 430.2 [Amended]

16. Section 430.2 is amended by removing the definition of ''ARM/simulation adjustment factor''.

PART 431—ENERGY EFFICIENCY PROGRAM FOR CERTAIN COMMERCIAL AND INDUSTRIAL EQUIPMENT

17. The authority citation for part 431 continues to read as follows:

Authority: 42 U.S.C. 6291–6317.

18. Section 431.2 is amended by revising the definition of ''alternative efficiency determination method or AEDM'' to read as follows:

§ 431.2 Definitions.

* * * * *

Alternative Efficiency Determination Method or AEDM is a simulation, calculation or engineering algorithm for determining the efficiency or consumption of a basic model of consumer product or commercial equipment, in terms of the appropriate descriptor used in or under section 325 or 342(a) of the Act to state the standard for that product.

* * * * *

19. Section 431.17 is amended by revising paragraph (a) to read as follows:

§ 431.17 Determination of efficiency.

* * * * *

(a*) Provisions applicable to all electric motors*— (1) *General requirements.* The average full load efficiency of each basic model of electric motor must be determined either by testing in accordance with § 431.16 of this subpart, or by application of an alternative efficiency determination method (AEDM) that meets the requirements of § 429.70, provided, however, that an AEDM may be used to determine the average full load efficiency of one or more of a manufacturer's basic models only if the average full load efficiency of at least five of its other basic models is determined through testing.

(2) *Alternative efficiency determination method.* An AEDM applied to a basic model must comply with § 429.70.

(3) *Use of a certification program or accredited laboratory.* (i) A manufacturer may have a certification program, that DOE has classified as nationally recognized under § 431.20, certify the nominal full load efficiency of a basic model of electric motor, and issue a certificate of conformity for the motor.

(ii) For each basic model for which a certification program is not used as described in paragraph (a)(3)(i) of this section, any testing of the motor pursuant to paragraphs (a)(1) through (2) of this section to determine its energy efficiency must be carried out in accordance with paragraph (b) of this section, in an accredited laboratory that meets the requirements of § 431.18. (This includes testing of the basic model, pursuant to § 429.70, to substantiate an AEDM.)

* * * * *

§ 431.442 [Amended]

20. Section 431.442 is revised by removing the definition of ''Alternative efficiency determination method''.

* * * * *

21. Section 431.445 is amended by:

a. Revising paragraph (b); and

b. Removing paragraph (c).

§ 431.445 Determination of small electric motor efficiency.

* * * * *

(b) *Provisions applicable to all small electric motors*—(1) *General requirements.* The average full load efficiency of each basic model of electric motor must be determined either by testing in accordance with § 431.444 of this subpart, or by application of an alternative efficiency determination method (AEDM) that meets the requirements of § 429.70, provided, however, that an AEDM may be used to determine the average full load efficiency of one or more of a manufacturer's basic models only if the average full load efficiency of at least five of its other basic models is determined through testing.

(2) *Alternative efficiency determination method.* To use an AEDM to rate a basic model, the AEDM must comply with § 429.70.

[FR Doc. 2012–13108 Filed 5–30–12; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2012–0497; Directorate Identifier 2011–NM–140–AD]

RIN 2120–AA64

Airworthiness Directives; The Boeing Company Airplanes

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: We propose to supersede an existing airworthiness directive (AD) that applies to certain The Boeing Company Model 777–200, –200LR, –300, and –300ER series airplanes. The existing AD currently requires inspecting for scribe lines in the skin along lap joints, butt joints, certain external doublers, and the large cargo door hinges, and related investigative and corrective actions if necessary. Since we issued that AD, we have determined that scribe lines could occur where external decals are installed or removed across lap joints, large cargo door hinges, or external doublers. This proposed AD would add inspecting for scribe lines where external decals have been applied or removed across lap joints, large cargo door hinges, and external doublers, and related investigative and corrective actions if necessary. We are proposing this AD to detect and correct scribe lines which can develop into fatigue cracks in the skin. Undetected fatigue cracks can grow and cause sudden decompression of the airplane.

DATES: We must receive comments on this proposed AD by July 16, 2012.

ADDRESSES: You may send comments, using the procedures found in 14 CFR 11.43 and 11.45, by any of the following methods:

- *Federal eRulemaking Portal:* Go to *http://www.regulations.gov.* Follow the instructions for submitting comments.
- *Fax:* 202–493–2251.
- *Mail:* U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room

W12–140, 1200 New Jersey Avenue SE., Washington, DC 20590.

• *Hand Delivery:* Deliver to Mail address above between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

For service information identified in this proposed AD, contact Boeing Commercial Airplanes, Attention: Data & Services Management, P.O. Box 3707, MC 2H–65, Seattle, Washington 98124–2207; phone: 206–544–5000, extension 1; fax: 206–766–5680; email: *me.boecom@boeing.com;* Internet: *https://www.myboeingfleet.com.* You may review copies of the referenced service information at the FAA, Transport Airplane Directorate, 1601 Lind Avenue SW., Renton, Washington. For information on the availability of this material at the FAA, call 425–227–1221.

Examining the AD Docket

You may examine the AD docket on the Internet at *http://www.regulations.gov;* or in person at the Docket Management Facility between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The AD docket contains this proposed AD, the regulatory evaluation, any comments received, and other information. The street address for the Docket Office (phone: 800–647–5527) is in the **ADDRESSES** section. Comments will be available in the AD docket shortly after receipt.

FOR FURTHER INFORMATION CONTACT:
Berhane Alazar, Aerospace Engineer, Airframe Branch, ANM–120S, FAA, Seattle Aircraft Certification Office (ACO), 1601 Lind Avenue SW., Renton, Washington 98057–3356; phone: 425–917–6577; fax: 425–917–6590; email: *Berhane.Alazar@faa.gov.*

SUPPLEMENTARY INFORMATION:

Comments Invited

We invite you to send any written relevant data, views, or arguments about this proposed AD. Send your comments to an address listed under the **ADDRESSES** section. Include ''Docket No. FAA–2012–0497; Directorate Identifier 2011–NM–140–AD'' at the beginning of your comments. We specifically invite comments on the overall regulatory, economic, environmental, and energy aspects of this proposed AD. We will consider all comments received by the closing date and may amend this proposed AD because of those comments.

We will post all comments we receive, without change, to *http://www.regulations.gov,* including any personal information you provide. We will also post a report summarizing each substantive verbal contact we receive about this proposed AD.

Discussion

On November 12, 2009, we issued AD 2009–24–08, Amendment 39–16096 (74 FR 62217, November 27, 2009), for certain Model 777–200, –200LR, –300, and –300ER series airplanes. That AD requires inspections for scribe lines in the skin along lap joints, butt joints, certain external doublers, and the large cargo door hinges, and related investigative and corrective actions if necessary. That AD resulted from reports of scribe lines found at lap joints and butt joints, around external doublers, and at locations where external decals had been removed. We issued that AD to detect and correct scribe lines, which can develop into fatigue cracks in the skin. Undetected fatigue cracks can grow and cause sudden decompression of the airplane.

Actions Since Existing AD 2009–24–08, Amendment 39–16096 (74 FR 62217, November 27, 2009) Was Issued

Since we issued AD 2009–24–08, Amendment 39–16096 (74 FR 62217, November 27, 2009), we have determined that scribe lines could occur where external decals are installed or removed across lap joints, large cargo door hinges, and external doublers. AD 2009–24–08 had exempted those areas from the required inspections. Those areas need to be inspected in order to address the identified unsafe condition.

Relevant Service Information

We reviewed Boeing Service Bulletin 777–53A0054, Revision 1, dated November 4, 2010. We referred to Boeing Alert Service Bulletin 777–53A0054, dated August 7, 2008, as the appropriate source of service information for accomplishing the required actions of AD 2009–24–08, Amendment 39–16096 (74 FR 62217, November 27, 2009). Boeing Service Bulletin 777–53A0054, Revision 1, dated November 4, 2010, describes an additional inspection to determine where external decals have been applied or removed across lap joints, large cargo door hinges, and external doublers on airplanes and areas that were previously determined to not require inspections as specified by the original issue of this service information (because the airplane had never been stripped or repainted). Where external decals have been applied or removed, Boeing Service Bulletin 777–53A0054, Revision 1, dated November 4, 2010, describes inspecting for scribe lines, and related investigative and corrective actions previously specified in the original issue of this service information.

FAA's Determination

We are proposing this AD because we evaluated all the relevant information and determined the unsafe condition described previously is likely to exist or develop in other products of the same type design.

Proposed AD Requirements

This proposed AD would retain all requirements of AD 2009–24–08, Amendment 39–16096 (74 FR 62217, November 27, 2009). This proposed AD would add an inspection to determine where external decals have been applied or removed across affected lap joints, large cargo door hinges, and external doublers. For locations where the inspections determine that external decals have been applied or removed, this proposed AD would require inspecting for scribe lines, and related investigative and corrective actions as described in AD 2009–24–08.

Differences Between the Proposed AD and the Service Information

Where Boeing Service Bulletin 777–53A0054, Revision 1, dated November 4, 2010, specifies contacting the manufacturer for instructions on how to repair certain conditions, this proposed AD would require repairing those conditions in one of the following ways:

• Using a method that we approve; or

• Using data that meet the certification basis of the airplane, and that have been approved by an Authorized Representative for The Boeing Commercial Airplanes Organization Designation Authorization (ODA) whom we have authorized to make those findings.

Boeing Service Bulletin 777–53A0054, Revision 1, dated November 4, 2010, does not specify a compliance time for doing the Part 11 actions of the Accomplishment Instructions. This proposed AD would require doing the Part 11 actions within 24 months after the effective date of the AD.

Costs of Compliance

We estimate that this proposed AD affects 163 airplanes of U.S. registry.

We estimate the following costs to comply with this proposed AD:

ESTIMATED COSTS

Action	Labor cost	Parts cost	Cost per product	Cost on U.S. operators
Exploratory inspection [retained action from AD 2009–24–08, Amendment 39–16096 (74 FR 62217, November 27, 2009)].	Up to 1,234 work-hours × $85 per hour = $104,890.	$0	Up to $104,890	Up to $17,097,070.
Inspection for decals [new proposed action]	Up to 4 work-hours × $85 per hour = $340.	0	Up to $340	Up to $55,420.

We have received no definitive data that would enable us to provide cost estimates for the on-condition actions specified in this proposed AD.

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),

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

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

List of Subjects in 14 CFR Part 39

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

The 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 FAA amends § 39.13 by removing airworthiness directive (AD) 2009–24–08, Amendment 39–16096 (74 FR 62217, November 27, 2009), and adding the following new AD:

The Boeing Company: Docket No. FAA–2012–0497; Directorate Identifier 2011–NM–140–AD.

(a) Comments Due Date

The FAA must receive comments on this AD action by July 16, 2012.

(b) Affected ADs

This AD supersedes AD 2009–24–08, Amendment 39–16096 (74 FR 62217, November 27, 2009).

(c) Applicability

This AD applies to The Boeing Company Model 777–200, –200LR, –300, and –300ER series airplanes; certificated in any category; as identified in Boeing Service Bulletin 777–53A0054, Revision 1, dated November 4, 2010.

(d) Subject

Joint Aircraft System Component (JASC)/Air Transport Association (ATA) of America Code 53, Fuselage.

(e) Unsafe Condition

This AD was prompted by reports of scribe lines found at lap joints and butt joints, around external doublers, at locations where external decals had been cut, and at locations where external decals have been installed or removed. We are issuing this AD to detect and correct scribe lines which can develop into fatigue cracks in the skin. Undetected fatigue cracks can grow and cause sudden decompression of the airplane.

(f) Compliance

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

(g) Retained Inspection With New Service Information and Additional Reporting

This paragraph restates the requirements of paragraph (g) of AD 2009–24–08, Amendment 39–16096 (74 FR 62217, November 27, 2009), with new service information and additional reporting. At the applicable times specified in paragraph 1.E., ''Compliance,'' of Boeing Alert Service Bulletin 777–53A0054, dated August 7, 2008, except as provided in paragraphs (h) and (j) of this AD: Do detailed exploratory inspections for scribe lines in the skin along lap joints, butt joints, certain external doublers, and the large cargo door hinges. Do all applicable related investigative and corrective actions at the times specified in Boeing Alert Service Bulletin 777–53A0054, dated August 7, 2008, by accomplishing all actions specified in the Accomplishment Instructions of Boeing Alert Service Bulletin 777–53A0054, dated August 7, 2008; or Boeing Service Bulletin 777–53A0054, Revision 1, dated November 4, 2010; except as provided by paragraph (i) of this AD. As of the effective date of this AD, use only Boeing Service Bulletin 777–53A0054, Revision 1, dated November 4, 2010, to do the actions required by this paragraph.

Note 1 to paragraph (g) of this AD: The inspection exceptions described in NOTES 1.–5. in Paragraph 1.E., ''Compliance,'' of Boeing Alert Service Bulletin 777–53A0054, dated August 7, 2008, apply to paragraph (g) of this AD.

(h) Retained Exception to Service Bulletin Specifications, Compliance Time

This paragraph restates the requirements of paragraph (h) of AD 2009–24–08, Amendment 39–16096 (74 FR 62217, November 27, 2009). Where Boeing Alert Service Bulletin 777–53A0054, dated August 7, 2008, specifies a compliance time after the date on that service bulletin, paragraph (g) of this AD requires compliance within the specified compliance time after January 4, 2010 (the effective date of AD 2009–24–08).

(i) Retained Exception to Service Bulletin Specifications, Contact for Appropriate Action With New Service Information

This paragraph restates the requirements of paragraph (i) of AD 2009–24–08, Amendment 39–16096 (74 FR 62217, November 27, 2009), with new service information. Where Boeing Alert Service Bulletin 777–53A0054, dated August 7, 2008; and Boeing Service Bulletin

777–53A0054, Revision 1, dated November 4, 2010; specify to contact Boeing for appropriate action, accomplish applicable actions using a method approved in accordance with the procedures specified in paragraph (q) of this AD.

(j) Retained Exception to Service Bulletin Specifications, Contact for Inspection Requirements

This paragraph restates the requirements of paragraph (j) of AD 2009–24–08, Amendment 39–16096 (74 FR 62217, November 27, 2009). Where paragraph 1.E. ''Compliance,'' of Boeing Alert Service Bulletin 777–53A0054, dated August 7, 2008, specifies to ''contact Boeing for inspection requirements for operation beyond 60,000 total flight-cycles after first repaint,'' for those airplanes, this AD requires contacting the Manager, Seattle Aircraft Certification Office (ACO), for all inspection requirements of this AD and doing the requirements.

(k) Retained Reporting

This paragraph restates the requirements of paragraph (k) of AD 2009–24–08, Amendment 39–16096 (74 FR 62217, November 27, 2009). At the applicable time specified in paragraph (k)(1) or (k)(2) of this AD: Submit a report of positive findings of cracks found during the inspection required by paragraphs (g) and (m) of this AD to the Boeing Commercial Airplane Group, P.O. Box 3707, Seattle, Washington 98124–2207. Alternatively, operators may submit reports to their Boeing field service representatives. The report must contain, at a minimum, the inspection results, a description of any discrepancies found, the airplane serial number, and the number of flight cycles and flight hours on the airplane. Under the provisions of the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*), the Office of Management and Budget (OMB) has approved the information collection requirements contained in this AD and has assigned OMB Control Number 2120–0056.

(1) If the inspection was done on or after the effective date of this AD: Submit the report within 30 days after the inspection.

(2) If the inspection was done before the effective date of this AD: Submit the report within 30 days after the effective date of this AD.

(l) New Inspection for External Decals

Within 24 months after the effective date of this AD: Inspect to determine the locations where external decals have been applied or removed across affected lap joints, large cargo door hinges, and external doublers, in accordance with the Accomplishment Instructions of Boeing Service Bulletin 777–53A0054, Revision 1, dated November 4, 2010.

(m) New Inspection for Scribe Lines and Related Investigative and Corrective Actions

If, during the inspection required by paragraph (l) of this AD, any location is found where external decals have been applied or removed across lap joints, large cargo door hinges, or external doublers: Before further flight, do a detailed exploratory inspection for scribe lines at all affected locations, in accordance with the Accomplishment Instructions of Boeing Service Bulletin 777–53A0054, Revision 1, dated November 4, 2010. Do all applicable related investigative and corrective actions at the times specified in Boeing Service Bulletin 777–53A0054, Revision 1, dated November 4, 2010, by accomplishing all actions specified in the Accomplishment Instructions of Boeing Service Bulletin 777–53A0054, Revision 1, dated November 4, 2010, except as provided by paragraph (i) of this AD.

(n) Exceptions to Service Information

(1) Where Boeing Service Bulletin 777–53A0054, Revision 1, dated November 4, 2010, specifies a compliance time after the date on that service bulletin, paragraphs (l) and (m) of this AD require compliance within the specified compliance time after the effective date of this AD.

(2) Where paragraph 1.E., ''Compliance,'' of Boeing Service Bulletin 777–53A0054, Revision 1, dated November 4, 2010, specifies to ''contact Boeing for inspection requirements for operation beyond 60,000 total flight-cycles after first repaint,'' for those airplanes, this AD requires contacting the Manager, Seattle ACO, for all inspection requirements of this AD and doing the requirements.

(o) Credit for Previous Actions

This paragraph provides credit for the actions required by paragraph (m) of this AD, if those actions were performed before the effective date of this AD using Boeing Alert Service Bulletin 777–53A0054, dated August 7, 2008.

(p) Paperwork Reduction Act Burden Statement

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2120–0056. Public reporting for this collection of information is estimated to be approximately 5 minutes per response, including the time for reviewing instructions, completing and reviewing the collection of information. All responses to this collection of information are mandatory. Comments concerning the accuracy of this burden and suggestions for reducing the burden should be directed to the FAA at: 800 Independence Ave. SW., Washington, DC 20591, Attn: Information Collection Clearance Officer, AES–200.

(q) Alternative Methods of Compliance (AMOCs)

(1) The Manager, Seattle ACO, FAA, has the authority to approve AMOCs for this AD, if requested using the procedures found in 14 CFR 39.19. In accordance with 14 CFR 39.19, send your request to your principal inspector or local Flight Standards District Office, as appropriate. If sending information directly to the manager of the ACO, send it to the attention of the person identified in the Related Information section of this AD. Information may be emailed to: *9–ANM–Seattle–ACO–AMOC–Requests@faa.gov.*

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

(3) An AMOC that provides an acceptable level of safety may be used for any repair required by this AD if it is approved by the Boeing Commercial Airplanes Organization Designation Authorization (ODA) that has been authorized by the Manager, Seattle ACO to make those findings. For a repair method to be approved, the repair must meet the certification basis of the airplane, and the approval must specifically refer to this AD.

(4) AMOCs approved for AD 2009–24–08, Amendment 39–16096 (74 FR 62217, November 27, 2009), are approved as AMOCs for the corresponding provisions of this AD, except that AMOCs approved for AD 2009–24–08 are not approved for fuselage areas where any decals may have been installed or removed on airplanes that have never been stripped or repainted since they left the factory.

(r) Related Information

(1) For more information about this AD, contact Berhane Alazar, Aerospace Engineer, Airframe Branch, ANM–120S, FAA, Seattle ACO, 1601 Lind Avenue SW., Renton, Washington 98057–3356; phone: 425–917–6577; fax: 425–917–6590; email: *Berhane.Alazar@faa.gov.*

(2) For service information identified in this AD, contact Boeing Commercial Airplanes, Attention: Data & Services Management, P.O. Box 3707, MC 2H–65, Seattle, Washington 98124–2207; phone: 206–544–5000, extension 1; fax: 206–766–5680; email: *me.boecom@boeing.com;* Internet: *https://www.myboeingfleet.com.* You may review copies of the referenced service information at the FAA, Transport Airplane Directorate, 1601 Lind Avenue SW., Renton, Washington. For information on the availability of this material at the FAA, call 425–227–1221.

Issued in Renton, Washington, on May 21, 2012.

Michael Kaszycki,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 2012–13169 Filed 5–30–12; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2012–0493; Directorate Identifier 2011–NM–180–AD]

RIN 2120–AA64

Airworthiness Directives; Airbus Airplanes

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: We propose to supersede an existing airworthiness directive (AD) for all Airbus Model A318–111 and –112 airplanes; and all Model A319, A320, and A321 series airplanes. The existing AD currently requires revising the Airworthiness Limitations Section (ALS) of the Instructions for Continued Airworthiness to incorporate new limitations for fuel tank systems. Since we issued that AD, Airbus has issued more restrictive maintenance requirements and/or airworthiness limitations. This proposed AD would revise the maintenance program to incorporate revised fuel maintenance and inspection tasks, and add airplanes to the applicability. We are proposing this AD to prevent the potential of ignition sources inside fuel tanks, which, in combination with flammable fuel vapors, could result in a fuel tank explosion and consequent loss of the airplane.

DATES: We must receive comments on this proposed AD by July 16, 2012.

ADDRESSES: You may send comments by any of the following methods:

- *Federal eRulemaking Portal:* Go to *http://www.regulations.gov.* Follow the instructions for submitting comments.
- *Fax:* (202) 493–2251.
- *Mail:* U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE., Washington, DC 20590.
- *Hand Delivery:* U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE., Washington, DC, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

For service information identified in this proposed AD, contact Airbus, Airworthiness Office—EAS, 1 Rond Point Maurice Bellonte, 31707 Blagnac Cedex, France; telephone +33 5 61 93 36 96; fax +33 5 61 93 44 51; email *account.airworth-eas@airbus.com;* Internet *http://www.airbus.com.* You may review copies of the referenced service information at the FAA, Transport Airplane Directorate, 1601 Lind Avenue SW., Renton, Washington. For information on the availability of this material at the FAA, call 425–227–1221.

Examining the AD Docket

You may examine the AD docket on the Internet at *http://www.regulations.gov;* or in person at the Docket Operations office between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The AD docket contains this proposed AD, the regulatory evaluation, any comments received, and other information. The street address for the Docket Operations office (telephone (800) 647–5527) is in the **ADDRESSES** section. Comments will be available in the AD docket shortly after receipt.

FOR FURTHER INFORMATION CONTACT: Sanjay Ralhan, Aerospace Engineer, International Branch, ANM–116, Transport Airplane Directorate, FAA, 1601 Lind Avenue SW., Renton, Washington 98057–3356; telephone (425) 227–1405; fax (425) 227–1149.

SUPPLEMENTARY INFORMATION:

Comments Invited

We invite you to send any written relevant data, views, or arguments about this proposed AD. Send your comments to an address listed under the **ADDRESSES** section. Include ''Docket No. FAA–2012–0493; Directorate Identifier 2011–NM–180–AD'' at the beginning of your comments. We specifically invite comments on the overall regulatory, economic, environmental, and energy aspects of this proposed AD. We will consider all comments received by the closing date and may amend this proposed AD based on those comments.

We will post all comments we receive, without change, to *http://www.regulations.gov,* including any personal information you provide. We will also post a report summarizing each substantive verbal contact we receive about this proposed AD.

Discussion

On November 16, 2009, we issued AD 2007–15–06 R1, Amendment 39–16097 (74 FR 62219, November 27, 2009). That AD required actions intended to address an unsafe condition on the products listed above.

Since we issued AD 2007–15–06 R1, Amendment 39–16097 (74 FR 62219, November 27, 2009), Airbus has issued A318/A319/A320/A321 Fuel Airworthiness Limitations, Document 95A.1931/05, Issue 4, dated August 26, 2010. The European Aviation Safety Agency (EASA), which is the Technical Agent for the Member States of the European Community, has issued EASA Airworthiness Directive 2011–0155, dated August 25, 2011 (referred to after this as ''the MCAI''), to correct an unsafe condition for the specified products. The MCAI states:

> The airworthiness limitations are currently published in the Airbus A318/A319/A320/A321 Airworthiness Limitations Section (ALS).
>
> The Fuel Airworthiness Limitations (FAL) are specified in Airbus A318/A319/A320/A321 FAL Document reference 95A.1931/05, which is approved by the European Aviation Safety Agency (EASA) and referenced in the Airbus A318/A319/A320/A321 ALS Part 5.
>
> The issue 4 of Airbus A318/A319/A320/A321 FAL Document introduces more restrictive maintenance requirements and/or airworthiness limitations. Failure to comply with these more restrictive maintenance requirements and airworthiness limitations contained in this document constitutes an unsafe condition.
>
> This [EASA] AD retains the requirement of EASA AD 2006–0203, which is superseded, and requires the implementation of the new or more restrictive maintenance requirements and/or airworthiness limitations as specified in Airbus A318/A319/A320/A321 FAL Document issue 4.

We are proposing this AD to prevent the potential of ignition sources inside fuel tanks, which, in combination with flammable fuel vapors, could result in a fuel tank explosion and consequent loss of the airplane. You may obtain further information by examining the MCAI in the AD docket.

Relevant Service Information

Airbus has issued A318/A319/A320/A321 Fuel Airworthiness Limitations, Document 95A.1931/05, Issue 4, dated August 26, 2010. The actions described in this service information are intended to correct the unsafe condition identified in the MCAI.

Explanation of Changes Made to This NPRM

We have changed Note 1 and Note 2 of the restated requirements of AD 2007–15–06 R1, Amendment 39–16097 (74 FR 62219, November 27, 2009), to lettered paragraphs (i) and (j), respectively, in this NPRM. These changes do not add any additional burden upon the public than was required in the existing AD.

FAA's Determination and Requirements of This Proposed AD

This product has been approved by the aviation authority of another country, and is approved for operation in the United States. Pursuant to our bilateral agreement with the State of Design Authority, we have been notified of the unsafe condition described in the MCAI and service information referenced above. We are proposing this AD because we evaluated all pertinent information and determined an unsafe condition exists and is likely to exist or develop on other products of the same type design.

Costs of Compliance

Based on the service information, we estimate that this proposed AD would affect about 745 products of U.S. registry.

The actions that are required by AD 2007–15–06 R1, Amendment 39–16097 (74 FR 62219, November 27, 2009), and retained in this proposed AD take about 2 work-hours per product, at an average labor rate of $85 per work hour. Required parts cost about $0 per product. Based on these figures, the estimated cost of the currently required actions is $170 per product.

We estimate that it would take about 2 work-hours per product to comply with the new basic requirements of this proposed AD. The average labor rate is $85 per work-hour. Based on these figures, we estimate the cost of the proposed AD on U.S. operators to be $126,650, or $170 per product.

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 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 this 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);

3. Will not affect intrastate aviation in Alaska; and

4. 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.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Incorporation by reference, 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 FAA amends § 39.13 by removing airworthiness directive (AD) 2007–15–06 R1, Amendment 39–16097 (74 FR 62219, November 27, 2009), and adding the following new AD:

Airbus: Docket No. FAA–2012–0493; Directorate Identifier 2011–NM–180–AD.

(a) Comments Due Date

We must receive comments by July 16, 2012.

(b) Affected ADs

This AD supersedes AD 2007–15–06 R1, Amendment 39–16097 (74 FR 62219, November 27, 2009).

(c) Applicability

(1) This AD applies to Airbus Model A318–111, –112, –121, and –122 airplanes; Model A319–111, –112, –113, –114, –115, –131, –132, and –133 airplanes; Model A320–111, –211, –212, –214, –231, –232, and –233 airplanes; Model A321–111, –112, –131, –211, –212, –213, –231, and –232 airplanes; certificated in any category; all serial numbers.

(2) This AD requires revisions to certain operator maintenance documents to include new actions (e.g., inspections and/or Critical Design Configuration Control Limitations (CDCCLs). Compliance with these actions is required by 14 CFR 91.403(c). For airplanes that have been previously modified, altered, or repaired in the areas addressed by these inspections, the operator may not be able to accomplish the inspections described in the revisions. In this situation, to comply with 14 CFR 91.403(c), the operator must request approval for an alternative method of compliance (AMOC) according to paragraph (l)(1) of this AD. The request should include a description of changes to the required actions that will ensure the continued operational safety of the airplane.

(d) Subject

Air Transport Association (ATA) of America Code 05, Periodic Inspections.

(e) Reason

This AD was prompted by Airbus issuing more restrictive maintenance requirements and/or airworthiness limitations. We are issuing this AD to prevent the potential of ignition sources inside fuel tanks, which, in combination with flammable fuel vapors, could result in a fuel tank explosion and consequent loss of the airplane.

(f) Compliance

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

(g) Retained Revision of the Airworthiness Limitations Section (ALS) To Incorporate Fuel Maintenance and Inspection Tasks

This paragraph restates the requirements of paragraph (f) of AD 2007–15–06 R1, Amendment 39–16097 (74 FR 62219, November 27, 2009). For Model A318–111 and –112 airplanes, and Model A319, A320, and A321 airplanes: Within 3 months after August 28, 2007 (the effective date of AD 2007–15–06), revise the ALS of the Instructions for Continued Airworthiness to incorporate Airbus A318/A319/A320/A321 ALS Part 5—Fuel Airworthiness Limitations, dated February 28, 2006, as defined in Airbus A318/A319/A320/A321 Fuel Airworthiness Limitations, Document 95A.1931/05, Issue 1, dated December 19, 2005 (approved by the European Aviation Safety Agency (EASA) on March 14, 2006), Section 1, ''Maintenance/Inspection Tasks;'' or Airbus A318/A319/A320/A321 Fuel Airworthiness Limitations, Document 95A.1931/05, Issue 2, dated July 8, 2008 (approved by the EASA on December 19, 2008), Section 1, ''Maintenance/Inspection Tasks.'' For all tasks identified in Section 1 of Airbus A318/A319/A320/A321 Fuel Airworthiness Limitations, Document 95A.1931/05, Issue 1, dated December 19, 2005; or Issue 2, dated July 8, 2008; the initial compliance times start from August 28, 2007, and the repetitive inspections must be accomplished thereafter at the intervals specified in Section 1, ''Maintenance/Inspection Tasks,'' of Airbus A318/A319/A320/A321 Fuel Airworthiness Limitations, Document 95A.1931/05, Issue 1, dated December 19, 2005; or Issue 2, dated July 8, 2008.

Note 1 to paragraph (g) of this AD: Airbus Operator Information Telex (OIT) SE 999.0076/06, dated June 20, 2006, provides guidance on identifying the applicable sections of the Airbus A318/A319/A320/A321 Airplane Maintenance Manual necessary for accomplishing the tasks specified in Section 1 ''Maintenance/Inspection Tasks,'' of Airbus A318/A319/A320/A321 Fuel Airworthiness Limitations, Document 95A.1931/05, Issue 1, dated December 19, 2005; or Issue 2, dated July 8, 2008.

(h) Retained Revision of the ALS To Incorporate CDCCLs

This paragraph restates the requirements of paragraph (g) of AD 2007–15–06 R1, Amendment 39–16097 (74 FR 62219, November 27, 2009). For Airbus Model A318–111 and –112 airplanes, and Model

A319, A320, and A321 airplanes: Within 12 months after August 28, 2007 (the effective date of AD 2007–15–06), revise the ALS of the Instructions for Continued Airworthiness to incorporate Airbus A318/A319/A320/A321 ALS Part 5–Fuel Airworthiness Limitations, dated February 28, 2006, as defined in Airbus A318/A319/A320/A321 Fuel Airworthiness Limitations, Document 95A.1931/05, Issue 1, dated December 19, 2005 (approved by the EASA on March 14, 2006), Section 2, ''Critical Design Configuration Control Limitations;'' or Airbus A318/A319/A320/A321 Fuel Airworthiness Limitations, Document 95A.1931/05, Issue 2, dated July 8, 2008 (approved by EASA on December 19, 2008), Section 2, ''Critical Design Configuration Control Limitations.''

(i) Retained No Alternative Inspections, Inspection Intervals, or CDCCLs

(1) This paragraph restates the requirements of paragraph (h) of AD 2007–15–06 R1, Amendment 39–16097 (74 FR 62219, November 27, 2009). Except as provided by paragraph (l) of this AD: After accomplishing the actions specified in paragraphs (g) and (h) of this AD, no alternative inspections, inspection intervals, or CDCCLs may be used.

(2) Notwithstanding any other maintenance or operational requirements, components that have been identified as airworthy or installed on the affected airplanes before the revision of the ALS, as required by paragraphs (g) and (h) of this AD, do not need to be reworked in accordance with the CDCCLs. However, once the ALS has been revised, future maintenance actions on these components must be done in accordance with the CDCCLs.

(j) Revise Maintenance Program

Within 6 months after the effective date of this AD: Revise the maintenance program to incorporate the new or revised tasks, life limits, and CDCCLs specified in Airbus A318/A319/A320/A321 Fuel Airworthiness Limitations, Document 95A.1931/05, Issue 4, dated August 26, 2010, except as required in paragraph (j)(4) of this AD. The initial compliance times and intervals are stated in these documents, except as required in paragraphs (j)(1) through (j)(4) of this AD, or within 6 months after the effective date of this AD, whichever occurs later. For certain tasks, the compliance times depend on the pre-modification and post-modification status of the airplane. Incorporating the requirements of this paragraph terminates the corresponding requirements of paragraphs (g) and (h) of this AD.

(1) For airplanes whose first flight occurred before August 28, 2007 (the effective date of AD 2007–15–06 R1, Amendment 39–16097 (74 FR 62219, November 27, 2009)), the first accomplishment of tasks 281800–01–1, Functional Check of Tank Vapour Seal and Vent Drain System; and 281800–02–1, Detailed Inspection of Vapour Seal; must be performed no later than 11 months after the effective date of this AD.

(2) The first accomplishment of Tasks 470000–01–1, Operational Check of DFSOV, Dual Flapper Check Valves and NEA Line for Leaks; 470000–02–1, Operational Check of both Dual Flapper Check Valves for Leaks; 470000–03–1, Operational Check of Dual Flapper Check Valves for Reverse Flow and NEA Line for Leaks; 470000–04–1, Operational Check of Dual Flapper Check Valves for Reverse Flow; and 470000–05–1, Remove Air Separation Module (ASM) and Return to Vendor for Workshop Check; must be calculated, in accordance with paragraphs (j)(2)(i) or (j)(2)(ii) of this AD.

(i) From the airplane first flight for airplanes on which Airbus modification 38062 or 38195 has been embodied in production, or

(ii) From the in-service installation of the fuel tank inerting system specified in Airbus Service Bulletin A320–47–1001, Airbus Service Bulletin A320–47–1002, Airbus Service Bulletin A320–47–1003, Airbus Service Bulletin A320–47–1004, Airbus Service Bulletin A320–47–1006, or Airbus Service Bulletin A320–47–1007.

(3) Although Airbus A318/A319/A320/A321 Fuel Airworthiness Limitations, Document 95A.1931/05, Issue 4, dated August 26, 2010, does not refer to Airbus Service Bulletin A320–47–1006 and Airbus Service Bulletin A320–47–1007, the tasks apply as follows:

(i) Tasks 470000–01–1, Operational Check of DFSOV, Dual Flapper Check Valves and NEA Line for Leaks; and 470000–02–1, Operational Check of both Dual Flapper Check Valves for leaks; apply to airplanes that have previously accomplished the actions specified in Airbus Service Bulletin A320–47–1007.

(ii) Task 470000–03–1, Operational Check of Dual Flapper Check Valves for Reverse Flow and NEA Line for Leaks; applies to airplanes that have previously accomplished the actions specified in Airbus Service Bulletin A320–47–1006, and that have not accomplished the actions specified in Airbus Service Bulletin A320–47–1007.

(iii) Task 470000–04–1, Operational Check of Dual Flapper Check Valves for Reverse Flow; applies to airplanes in post-modification 38195 configuration and that have not accomplished the actions specified in Airbus Service Bulletin A320–47–1007.

(iv) Task 470000–05–1, Remove ASM and return to Vendor for workshop check; applies to airplanes that have previously accomplished the actions specified in Airbus Service Bulletin A320–47–1007, and are in pre-modification 151529 configuration.

(4) Replace each ASM identified in table 1 of this AD in accordance with a method approved by either the Manager, International Branch, ANM–116, Transport Airplane Directorate, FAA; or the European Aviation Safety Agency (EASA) (or its delegated agent). The compliance time for the replacement is before the accumulation of 27,000 flight hours (component time)—i.e., the life limitation.

Note 2 to paragraph (g)(4) of this AD: Airbus A318/A319/A320/A321 Maintenance Manual Task 47–10–43–920–001–A, Air Separation Module Replacement, is an additional source of guidance for accomplishment of the removal and replacement of the ASM.

TABLE 1—ASM REPLACEMENT

ASM Part No.	Affected airplane configuration
2060017–101	Post-modification 38062, or Post-Airbus Service Bulletin A320–47–1002, or Post-Airbus Service Bulletin A320–47–1004, or Post-Airbus Service Bulletin A320–47–1007
2060017–102	Post-modification 152033, or Post-Airbus Service Bulletin A320–47–1011

(k) No Alternative Actions Intervals, and/or CDCCLs

After accomplishing the revisions required by paragraph (j) of this AD, no alternative actions (e.g., inspections), intervals, and/or CDCCLs may be used other than those specified in Airbus A318/A319/A320/A321 ALS Part 5—Fuel Airworthiness Limitations, dated February 28, 2006, as defined in Airbus A318/A319/A320/A321 Fuel Airworthiness Limitations, Document 95A.1931/05, Issue 4, dated August 26, 2010, unless the actions, intervals, and/or CDCCLs are approved as an AMOC in accordance with the procedures specified in paragraph (l)(1) of this AD.

(l) Other FAA AD Provisions

The following provisions also apply to this AD:

(1) Alternative Methods of Compliance (AMOCs): The Manager, International Branch, ANM–116, has the authority to approve AMOCs for this AD, if requested using the procedures found in 14 CFR 39.19. In accordance with 14 CFR 39.19, send your request to your principal inspector or local Flight Standards District Office, as appropriate. If sending information directly to the International Branch, send it to ATTN: Sanjay Ralhan, Aerospace Engineer, International Branch, ANM–116, Transport Airplane Directorate, FAA, 1601 Lind Avenue SW., Renton, Washington 98057–3356; telephone (425) 227–1405; fax (425) 227–1149. Information may be emailed to:

9-ANM-116-AMOC-REQUESTS@faa.gov. Before using any approved AMOC, notify your appropriate principal inspector, or lacking a principal inspector, the manager of the local flight standards district office/certificate holding district office. The AMOC approval letter must specifically reference this AD.

(2) Airworthy Product: For any requirement in this AD to obtain corrective actions from a manufacturer or other source, use these actions if they are FAA-approved. Corrective actions are considered FAA-approved if they are approved by the State of Design Authority (or their delegated agent). You are required to assure the product is airworthy before it is returned to service.

(m) Related Information

(1) Refer to MCAI EASA Airworthiness Directive 2011–0155, dated August 25, 2011, and the following service information, for related information.

(i) Airbus A318/A319/A320/A321 ALS Part 5—Fuel Airworthiness Limitations, dated February 28, 2006.

(ii) Airbus A318/A319/A320/A321 Fuel Airworthiness Limitations, Document 95A.1931/05, Issue 1, dated December 19, 2005.

(iii) A318/A319/A320/A321 Fuel Airworthiness Limitations, Document 95A.1931/05, Issue 2, dated July 8, 2008.

(iv) Airbus A318/A319/A320/A321 Fuel Airworthiness Limitations, Document 95A.1931/05, Issue 4, dated August 26, 2010.

(2) For service information identified in this AD, contact Airbus, Airworthiness Office—EAS, 1 Rond Point Maurice Bellonte, 31707 Blagnac Cedex, France; telephone +33 5 61 93 36 96; fax +33 5 61 93 44 51; email *account.airworth-eas@airbus.com;* Internet *http://www.airbus.com.* You may review copies of the referenced service information at the FAA, Transport Airplane Directorate, 1601 Lind Avenue SW., Renton, Washington. For information on the availability of this material at the FAA, call 425–227–1221.

Issued in Renton, Washington, on May 18, 2012.

Michael Kaszycki,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 2012–13191 Filed 5–30–12; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2012–0492; Directorate Identifier 2010–NM–126–AD]

RIN 2120–AA64

Airworthiness Directives; The Boeing Company Model 747 Airplanes

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

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: We propose to supersede an existing airworthiness directive (AD) that applies to certain The Boeing Company Model 747 airplanes. The existing AD currently requires repetitive visual inspections around the bushings of the wing landing gear (WLG) beam outboard end fittings for corrosion, and rework if necessary; and ultrasonic inspections for cracks of the outboard end fittings of the WLG support beams, and rework if necessary. Since we issued that AD, there have been new reports of corrosion damage to the end fittings of the WLG support beams, and one report of subsequent cracking in the end fittings. This proposed AD would add airplanes and repetitive inspections of the outboard end fitting of the left and right WLG support beams for cracks and corrosion, and corrective actions if necessary. We are proposing this AD to detect and correct corrosion and subsequent cracking in the outboard end fittings, which could result in separation of the fitting and damage to adjacent flight control cables and hydraulic systems and consequent reduced controllability of the airplane.

DATES: We must receive comments on this proposed AD by July 16, 2012.

ADDRESSES: You may send comments by any of the following methods:

- *Federal eRulemaking Portal:* Go to *http://www.regulations.gov.* Follow the instructions for submitting comments.
- *Fax:* 202–493–2251.
- *Mail:* U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE., Washington, DC 20590.
- *Hand Delivery:* U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE., Washington, DC 20590, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

For service information identified in this proposed AD, contact Boeing Commercial Airplanes, Attention: Data & Services Management, P.O. Box 3707, MC 2H–65, Seattle, Washington 98124–2207; telephone 206–544–5000, extension 1, fax 206–766–5680; email *me.boecom@boeing.com;* Internet *https://www.myboeingfleet.com.* You may review copies of the referenced service information at the FAA, Transport Airplane Directorate, 1601 Lind Avenue SW., Renton, Washington. For information on the availability of this material at the FAA, call 425–227–1221.

Examining the AD Docket

You may examine the AD docket on the Internet at *http://www.regulations.gov;* or in person at the Docket Management Facility between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The AD docket contains this proposed AD, the regulatory evaluation, any comments received, and other information. The street address for the Docket Office (telephone 800–647–5527) is in the **ADDRESSES** section. Comments will be available in the AD docket shortly after receipt.

FOR FURTHER INFORMATION CONTACT: Bill Ashforth, Aerospace Engineer, Airframe Branch, ANM–120S, FAA, Seattle Aircraft Certification Office, 1601 Lind Avenue SW., Renton, Washington 98057–3356; phone: (425) 917–6432; fax: (425) 917–6590; email: *bill.ashforth@faa.gov.*

SUPPLEMENTARY INFORMATION:

Comments Invited

We invite you to send any written relevant data, views, or arguments about this proposed AD. Send your comments to an address listed under the **ADDRESSES** section. Include ''Docket No. FAA–2012–0492; Directorate Identifier 2010–NM–126–AD'' at the beginning of your comments. We specifically invite comments on the overall regulatory, economic, environmental, and energy aspects of this proposed AD. We will consider all comments received by the closing date and may amend this proposed AD because of those comments.

We will post all comments we receive, without change, to *http://www.regulations.gov,* including any personal information you provide. We will also post a report summarizing each substantive verbal contact we receive about this proposed AD.

Discussion

On July 7, 1989, we issued AD 89–15–07, amendment 39–6267 (54 FR 30009, July 18, 1989), for certain Model 747 airplanes. That AD requires visual inspections around the bushings of the wing landing gear for corrosion, and repair if necessary, and ultrasonic inspections for cracks of the outboard end fittings of the WLG support beams, and overhaul if necessary. That AD resulted from a report of a fracture of the outboard end fitting of a left WLG beam. We issued that AD to prevent failure of the outboard end fitting of a WLG beam with possible damage to control cables or hydraulic lines in the area of the landing gear beam.

Actions Since Existing AD Was Issued

Since we issued AD 89–15–07, amendment 39–6267 (54 FR 30009, July 18, 1989), we have received new reports of corrosion damage to the end fittings of the WLG support beams, and one report of subsequent cracking in the end fittings. The end fittings are installed on the outboard ends of the WLG support beams, and they attach to gate fittings installed on the rear wing spars. There are two types of end fittings used—one is a two-piece end fitting installed in a ''back to back'' configuration; the other is a one-piece end fitting.

Boeing Service Bulletin 747–57–2244, Revision 1, dated July 28, 1988, was referred to in the existing AD for accomplishing the required actions on Model 747 airplanes having line numbers 1 through 695. The terminating action specified in that service bulletin involves replacing each of the end fitting lug bore and bolt hole bushings with new standard or oversize bushings which are installed with sealant to provide better corrosion prevention. That terminating action was incorporated into the design of replacement fittings used on production airplanes having line numbers 696 and subsequent.

Although the terminating action seemed to work well on airplanes having line numbers 1 through 695, recent reports from operators of airplanes having line numbers 696 and subsequent revealed that the problem occurred again. Further investigation revealed that the corrosion started at the lug bore and bushing interface because moisture continued to develop in that area due to exposure of the end fittings to environmental conditions. Subsequently, cracks have occurred at the corroded areas of the end fittings; therefore, the terminating action in that service bulletin is no longer valid because the unsafe condition specified in the existing AD has not been corrected.

Relevant Service Information

Since the issuance of AD 89–15–07, amendment 39–6267 (54 FR 30009, July 18, 1989), Boeing has issued Alert Service Bulletin 747–57A2331, dated November 12, 2009. This new service information is applicable to Model 747 airplanes having line numbers 1 through 1419 inclusive, which includes airplanes on which the terminating action in AD 89–15–07 was done.

We have reviewed Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009. This service bulletin describes procedures for repetitive detailed and ultrasonic inspections, as applicable, for cracks and corrosion of the end fittings of the left and right WLG support beams; and repetitive detailed inspections of the fillet seal for damage, as applicable. The service information describes necessary actions and options after accomplishing the inspections, depending on the findings and configurations. Those actions and options (including Options 1A and 1B) include the following:

• Repairing or changing each end fitting (by installing higher interference fit bushings on the end fitting), which is identified as ''Part 7'' of this service bulletin, may be done in lieu of the inspections described previously, but is necessary for findings of cracks or corrosion.

• Repetitively inspecting, as described previously, along with an additional inspection of the fillet seal for damage; and applying corrosion inhibiting compound or doing ''Part 7'' of this service bulletin, if necessary.

• Doing ''Post-Part 7 inspections,'' which involves actions similar to the inspections for cracks, corrosion, and damage described previously.

The recommended compliance times follow:

• Detailed and ultrasonic inspections: The initial compliance time for these inspections depends on configuration, and is either (1) 8 years on the end fitting and 18 months after the date on this service bulletin (whichever is later); or (2) 10 years on the end fitting and 24 months after the date on this service bulletin (whichever is later). The repetitive interval also depends on configurations and findings, and ranges between 12 and 24 months.

• ''Part 7'' of this service bulletin: The initial compliance time is the later of 20,000 total flight cycles on an end fitting, and either 18 or 24 months (depending on configuration). The repetitive interval is either 13,000 or 16,000 flight cycles on an end fitting; depending on configuration.

• ''Post-Part 7'' inspections: The compliance time is 12 years after the repair or change. The subsequent repetitive intervals range between 12 months and 36 months, depending on findings and configurations.

For airplanes on which any crack, corrosion, or damage is found, the compliance time for ''Part 7'' or application of corrosion inhibitor is before further flight.

FAA's Determination

We are proposing this AD because we evaluated all the relevant information and determined the unsafe condition described previously is likely to exist or develop in other products of the same type design.

Proposed AD Requirements

This proposed AD would retain certain requirements of the existing AD. This proposed AD would also add airplanes and require accomplishing the actions specified in the service information described previously.

Changes to Existing AD

We have changed the applicability of AD 89–15–07, amendment 39–6267 (54 FR 30009, July 18, 1989), in this proposed AD to identify model designations as published in the most recent type certificate data sheet for the affected models. We have also changed the legal name of the manufacturer as published in the most recent type certificate data sheet for the affected airplane models.

This proposed AD would retain certain requirements of AD 89–15–07, amendment 39–6267 (54 FR 30009, July 18, 1989). Since AD 89–15–07 was issued, the AD format has been revised, and certain paragraphs have been rearranged. As a result, the corresponding paragraph identifiers have changed in this proposed AD, as listed in the following table:

REVISED PARAGRAPH IDENTIFIERS

Requirement in AD 89–15–07, Amendment 39–6267 (54 FR 30009, July 18, 1989)	Corresponding requirement in this proposed AD
paragraph A	paragraph (g)
paragraph B	paragraph (g)(1)
paragraph C	paragraph (g)(2)
paragraph D	paragraph (g)(3)

In addition, we have revised paragraph (g)(3) of this proposed AD (which was designated as paragraph D. in the existing AD) to require that if any corrosion is found after the effective date of this proposed AD, rework is required before further flight. We have reduced the compliance time to do the rework from ''within 12 months'' to ''before further flight'' because extensive service history has shown that the deferral of known airplane damage such as cracks and corrosion has not provided an acceptable level of safety. Service history has shown that the extent of damage from unrepaired corrosion can not reliably be determined by inspection techniques. The damaged corroded material must first be removed and only then can the remaining material dimensions be accurately compared to the allowable damage limits. The extent of unrepaired corrosion damage can not be accurately determined by current inspection methods. Further, the reliance for operation with known damage is predicated on the adjacent and associated structure being free from other damage during this time period, which has not been demonstrated by older airplanes.

Depending on airplane configuration, the new proposed inspections would take between 1 and 4 work hours per airplane, at an average labor rate of $85 per work hour. Based on these figures, the estimated cost of the new inspections specified in this proposed AD for U.S. operators is between $14,705 and $58,820, or between $85 and $340 per airplane, per inspection cycle.

Difference Between the Proposed AD and the Service Information

Operators should note that Conditions 6, 13, and 16 of paragraph 1.E., ''Compliance,'' of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009, specify a detailed inspection. However, the corresponding conditions in the Accomplishment Instructions of this service bulletin specify both detailed and high frequency eddy current (HFEC) inspections. We have confirmed with Boeing that its intent is that this service bulletin specify only a detailed inspection for those conditions.

Costs of Compliance

We estimate that this proposed AD affects 173 airplanes of U.S. registry. We estimate the following costs to comply with this proposed AD:

ESTIMATED COSTS

Action	Labor cost	Parts cost	Cost per product	Cost on U.S. operators
Inspections [retained actions from existing AD 89–15–07, amendment 39–6267 (54 FR 30009, July 18, 1989)].	10 work-hours × $85 per hour = $850 per inspection cycle.	$0	$850 per inspection cycle	$147,050 per inspection cycle.
Inspections [new proposed action].	Up to 67 work-hours × $85 per hour = $5,695 per inspection cycle, depending on configuration.	0	Up to $5,695 per inspection cycle, depending on configuration.	Up to $985,235 per inspection cycle, depending on configuration.

We estimate the following costs to do any necessary repairs/replacements that would be required based on the results of the proposed inspection. We have no way of determining the number of aircraft that might need these repairs/replacements:

ON-CONDITION COSTS

Action	Labor cost	Parts cost	Cost per product
Repair or replacement	Up to 71 work-hours × $85 per hour = $6,035, depending on configuration.	Up to $26,436, depending on configuration.	Up to $32,471, depending on configuration.

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 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 this 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),

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

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

List of Subjects in 14 CFR Part 39

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

The 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 FAA amends § 39.13 by removing airworthiness directive (AD) 89–15–07, Amendment 39–6267 (54 FR 30009, July 18, 1989), and adding the following new AD:

The Boeing Company: Docket No. FAA–2012–0492; Directorate Identifier 2010–NM–126–AD.

(a) Comments Due Date

The FAA must receive comments on this AD action by July 16, 2012.

(b) Affected ADs

This AD supersedes AD 89–15–07, Amendment 39–6267 (54 FR 30009, July 18, 1989).

(c) Applicability

This AD applies to The Boeing Company Model 747–100, 747–100B, 747–100B SUD, 747–200B, 747–200C, 747–200F, 747–300, 747–400, 747–400D, 747–400F, 747SR, and 747SP series airplanes; certificated in any category; as identified in Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009.

(d) Subject

Joint Aircraft System Component (JASC)/Air Transport Association (ATA) of America Code 57, Wings.

(e) Unsafe Condition

This AD was prompted by new reports of corrosion damage to the end fittings of the wing landing gear (WLG) support beams, and one report of subsequent cracking in the end fittings. We are issuing this AD to detect and correct corrosion and subsequent cracking in the outboard end fittings, which could result in separation of the fitting and damage to adjacent flight control cables and hydraulic systems and consequent reduced controllability of the airplane.

(f) Compliance

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

(g) Retained Repetitive Inspections With Revised Compliance Times

This paragraph restates the requirements of paragraphs A., B., C., and D., of AD 89–15–07, Amendment 39–6267 (54 FR 30009, July 18, 1989): For airplanes identified in Boeing Service Bulletin 747–57–2244, Revision 1, dated July 28, 1988: Prior to the accumulation of 30,000 flight hours or 8 years in service, whichever occurs first; or within the next 14 months after August 22, 1989 (the effective date of AD 89–15–07); whichever occurs later; visually inspect around the fitting lug bushings at the wing landing gear (WLG) beam outboard end fittings for corrosion, and ultrasonically inspect the WLG beam outboard end fittings for cracks, in accordance with Boeing Service Bulletin 747–57–2244, Revision 1, dated July 28, 1988. Accomplishing the initial inspections required by paragraph (j) of this AD terminates the inspections required by this paragraph.

(1) If no cracking or corrosion is found, repeat the inspections at intervals not to exceed 18 months until paragraph (j) of this AD has been accomplished.

(2) If cracking is found, prior to further flight, remove the WLG beam outboard fitting, and rework, in accordance with Boeing Service Bulletin 747–57–2244, Revision 1, dated July 28, 1988.

(3) If only corrosion is found, within the next 12 months, rework in accordance with Boeing Service Bulletin 747–57–2244, Revision 1, dated July 28, 1988. The ultrasonic inspections for cracks required by paragraph (g) of this AD must be accomplished at intervals not to exceed 6 months until the rework is accomplished. For any corrosion that is found after the effective date of this AD, the rework must be done before further flight.

(h) Retained Terminating Action

This paragraph restates the requirements of paragraph E., of AD 89–15–07, Amendment 39–6267 (54 FR 30009, July 18, 1989): Terminating action for the inspections required by paragraph (g) of this AD consists of rework of the WLG beam outboard fittings, in accordance with Boeing Service Bulletin 747–57–2244, Revision 1, dated July 28, 1988.

(i) New Compliance Times for This AD

For all the actions identified in paragraphs (j) through (t) of this AD, do the actions at the applicable time specified in paragraph 1.E., ''Compliance,'' of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009. Where paragraph 1.E., ''Compliance'' of this service bulletin specifies a compliance time relative to the original issue date of the service bulletin, this AD requires compliance within the specified compliance time after the effective date of this AD.

(j) New Repetitive Inspections for Groups 1 Through 5 Airplanes

For Groups 1 through 3 airplanes, Configurations 1 and 2; and Groups 4 and 5 airplanes: Do detailed and ultrasonic inspections of the end fittings for cracks and corrosion, in accordance with Part 1 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009.

(k) New Inspections for No Crack or Corrosion Findings for Groups 1 Through 5 Airplanes

If no crack or corrosion is found during any inspection required by paragraph (j) of this AD, do either of the actions required by paragraph (k)(1) or (k)(2) of this AD.

(1) Repeat the detailed and ultrasonic inspections of the end fittings for cracks and corrosion, in accordance with Part 1 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009.

(2) Do a detailed inspection of the end fittings for fillet seal damage and for cracks and corrosion, in accordance with Part 2 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009.

(i) If no fillet seal damage, crack, or corrosion is found: Repeat the inspection required by paragraph (k)(2) of this AD.

(ii) If any fillet seal damage is found, but no crack or corrosion is found: Remove the fillet seal, and do detailed and HFEC inspections of each end fitting for cracks and corrosion, in accordance with Part 2 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009.

(A) If any crack or corrosion is found: Repair or change the end fitting, in accordance with paragraph (l) of this AD.

(B) If no crack or corrosion is found: Apply corrosion inhibiting compound on each end fitting, in accordance with Part 2 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009; and do detailed and HFEC inspections of each end fitting for cracks and corrosion, in accordance with Part 3 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009.

(*1*) If no crack or corrosion is found: Apply corrosion inhibiting compound on each end fitting, in accordance with Part 3 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009, and thereafter repeat the inspections required by paragraph (k)(2)(ii)(B) of this AD.

(*2*) If any crack or corrosion is found: Repair or change the end fitting, in accordance with paragraph (l) of this AD.

(l) New Repair for Crack or Corrosion Findings for Groups 1 Through 5 Airplanes

If any crack or corrosion is found during any inspection required by paragraph (j) or (k) of this AD: Repair or change the end fitting, in accordance with Part 7 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009. After accomplishing the repair or change in accordance with Part 7 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009, do the applicable actions required by paragraph (j) of this AD.

(m) New Repetitive Inspections and Corrective Actions for Group 6 Airplanes

For Group 6 airplanes: Do a detailed inspection of the end fittings for fillet seal damage and for cracks and corrosion, in accordance with Part 1 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009.

(1) If no fillet seal damage, crack, or corrosion is found: Do the detailed inspection of the end fittings for fillet seal damage and for cracks and corrosion, in accordance with Part 2 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009.

(i) If no fillet seal damage, crack, or corrosion is found: Repeat the detailed inspection required by paragraph (m)(1) of this AD.

(ii) If any fillet seal damage is found, but no crack or corrosion is found: Remove the fillet seal, and do detailed and HFEC inspections of each end fitting for cracks and corrosion, in accordance with Part 2 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009.

(A) If any crack or corrosion is found: Repair or change the end fitting, in accordance with paragraph (n) of this AD.

(B) If no crack or corrosion is found: Apply corrosion inhibiting compound on each end fitting, in accordance with Part 2 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009; and do detailed and HFEC inspections of each end fitting for cracks and corrosion, in accordance with Part

3 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009.

(*1*) If any crack or corrosion is found: Repair or change the end fitting, in accordance with paragraph (n) of this AD.

(*2*) If no crack or corrosion is found: Apply corrosion inhibiting compound, in accordance with Part 3 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009, and thereafter repeat the inspections required by paragraph (m)(1)(ii)(B) of this AD.

(2) If any fillet seal damage is found, but no crack or corrosion is found: Remove the fillet seal, and do detailed and HFEC inspections of each end fitting for cracks and corrosion, in accordance with Part 1 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009.

(i) If any crack or corrosion is found: Repair or change the end fitting, in accordance with paragraph (n) of this AD.

(ii) If no crack or corrosion is found: Apply corrosion inhibiting compound on each end fitting, in accordance with Part 1 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009; and do detailed and HFEC inspections of each end fitting for cracks and corrosion, in accordance with Part 3 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009.

(A) If any crack or corrosion is found: Repair or change the end fitting, in accordance with paragraph (n) of this AD.

(B) If no crack or corrosion is found: Apply corrosion inhibiting compound, in accordance with Part 3 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009, and thereafter repeat the inspections required by paragraph (m)(2)(ii) of this AD.

(n) New Repair for Group 6 Airplanes

If any crack or corrosion is found during any inspection required by paragraph (m) of this AD: Repair or change the end fitting, in accordance with Part 7 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009. After accomplishing the repair or change in accordance with Part 7 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009, do the applicable actions required by paragraph (m) of this AD.

(o) New Optional Terminating Action for Part 1, Part 2, and Part 3 Inspections

In lieu of doing Part 1, Part 2, or Part 3 inspections required by this AD: Repair or change the end fitting, in accordance with Part 7 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009. After accomplishing the repair or change in accordance with Part 7 of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009, do the applicable actions required by paragraphs (p) and (r) of this AD. Doing the repair or change terminates the Part 1, 2, or 3 inspections for that part only of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009.

(p) New Follow-On End Fitting Inspection for Groups 1 Through 5 Airplanes

For Groups 1 through 5 airplanes on which the repair or change specified in Part 7 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009, has been done: Do detailed and ultrasonic inspections of the end fittings for cracks and corrosion, in accordance with Part 4 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009. If no crack or corrosion is found, do the actions required by either paragraph (p)(1) or (p)(2) of this AD.

(1) Repeat the detailed and ultrasonic inspections of the end fittings for cracks and corrosion required by paragraph (p) of this AD.

(2) Do a detailed inspection of each end fitting for fillet seal damage, cracks, and corrosion, in accordance with Part 5 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009.

(i) If no fillet seal damage, crack, or corrosion is found: Repeat the inspection required by paragraph (p)(2) of this AD.

(ii) If any fillet seal damage is found, but no crack or corrosion is found: Remove the fillet seal, and do detailed and HFEC inspections of each end fitting for cracks and corrosion, in accordance with Part 5 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009.

(A) If any crack or corrosion is found: Repair or change the end fitting, as required by paragraph (q) of this AD.

(B) If no crack or corrosion is found: Apply corrosion inhibiting compound on each end fitting, in accordance with Part 5 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009; and do detailed and HFEC inspections of each end fitting for cracks and corrosion, in accordance with Part 6 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009.

(*1*) If any crack or corrosion is found: Repair or change the end fitting, as required by paragraph (q) of this AD.

(*2*) If no crack or corrosion is found: Apply corrosion inhibiting compound, in accordance with Part 6 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009; and repeat the detailed and HFEC inspections of each end fitting for cracks and corrosion, in accordance with Part 6 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009.

(q) New Repair for Groups 1 Through 5 Airplanes

If any crack or corrosion is found during any inspection required by paragraph (p) of this AD: Repair or change the end fitting, in accordance with Part 7 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009. After accomplishing the repair or change in accordance with Part 7 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009, do the applicable actions required by paragraphs (p) of this AD.

(r) New Follow-On End Fitting Inspection for Group 6 Airplanes

For Group 6 airplanes on which the repair or change specified in Part 7 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009, has been done: Do a detailed inspection of the end fittings for fillet seal damage, cracks, and corrosion, in accordance with Part 4 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009.

(1) If no fillet seal damage, crack, or corrosion is found: Do a detailed inspection of each end fitting for fillet seal damage, cracks, and corrosion, in accordance with Part 5 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009.

(i) If no fillet seal damage, crack, or corrosion is found: Repeat the inspection required by paragraph (r)(1) of this AD.

(ii) If any fillet seal damage is found, but no crack or corrosion is found: Do detailed and HFEC inspections of each end fitting for cracks and corrosion, in accordance with Part 5 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009.

(A) If any crack or corrosion is found: Repair or change the end fitting as required by paragraph (s) of this AD.

(B) If no crack or corrosion is found: Apply corrosion inhibiting compound on each end fitting, in accordance with Part 5 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009; and repeat the detailed and HFEC inspections of each end fitting for cracks and corrosion, in accordance with Part 6 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009.

(*1*) If any crack or corrosion is found: Repair or change the end fitting, in accordance with Part 7 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009.

(*2*) If no crack or corrosion is found: Apply corrosion inhibiting compound, in accordance with Part 6 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009; and repeat the detailed and HFEC inspections of each end fitting for cracks and corrosion, in accordance with Part 6 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009.

(2) If any fillet seal damage is found, but no crack or corrosion is found: Do detailed and HFEC inspections of each end fitting for cracks and corrosion, in accordance with Part 4 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009.

(i) If any crack or corrosion is found: Repair or change the end fitting, as required by paragraph (s) of this AD.

(ii) If no crack or corrosion is found: Apply corrosion inhibiting compound on each end fitting, in accordance with Part 4 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009, and do detailed and HFEC inspections of each end fitting for cracks and corrosion, in accordance with Part 6 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009.

(A) If any crack or corrosion is found: Repair or change the end fitting, as required by paragraph (s) of this AD.

(B) If no crack or corrosion is found: Apply corrosion inhibiting compound, in accordance with Part 6 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009; and repeat the detailed and HFEC inspections of each end fitting for cracks and corrosion, in accordance with Part 6 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009.

(s) New Repair for Group 6 Airplanes

If any crack or corrosion is found during any inspection required by paragraph (r) of this AD: Repair or change the end fitting, in accordance with Part 7 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009.

(t) New Optional Action for Part 4, Part 5, and Part 6 Inspections

In lieu of doing Part 4, Part 5, or Part 6 inspections required by this AD: Repair or change the end fitting, in accordance with Part 7 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009. After accomplishing the repair or change in accordance with Part 7 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–57A2331, dated November 12, 2009, do the applicable actions required by paragraphs (p) and (r) of this AD.

(u) Alternative Methods of Compliance (AMOCs)

(1) The Manager, Seattle Aircraft Certification Office (ACO), FAA, has the authority to approve AMOCs for this AD, if requested using the procedures found in 14 CFR 39.19. In accordance with 14 CFR 39.19, send your request to your principal inspector or local Flight Standards District Office, as appropriate. If sending information directly to the manager of the ACO, send it to the attention of the person identified in the Related Information section of this AD. Information may be emailed to: *9-ANM-Seattle-ACO-AMOC-Requests@faa.gov.*

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

(3) An AMOC that provides an acceptable level of safety may be used for any repair required by this AD if it is approved by the Boeing Commercial Airplanes Organization Designation Authorization (ODA) that has been authorized by the Manager, Seattle ACO, to make those findings. For a repair method to be approved, the repair must meet the certification basis of the airplane, and the approval must specifically refer to this AD.

(4) AMOCs approved for AD 89–15–07, Amendment 39–6267 (54 FR 30009, July 18, 1989), are approved as AMOCs for the corresponding requirements of this AD.

(v) Related Information

(1) For more information about this AD, contact Bill Ashforth, Aerospace Engineer, Airframe Branch, ANM–120S, FAA, Seattle Aircraft Certification Office, 1601 Lind Avenue SW., Renton, Washington 98057–3356; phone: (425) 917–6432; fax: (425) 917–6590; email: *bill.ashforth@faa.gov.*

(2) For service information identified in this AD, contact Boeing Commercial Airplanes, Attention: Data & Services Management, P.O. Box 3707, MC 2H–65, Seattle, Washington 98124–2207; telephone 206–544–5000, extension 1, fax 206–766–5680; email *me.boecom@boeing.com;* Internet *https://www.myboeingfleet.com.* You may review copies of the referenced service information at the FAA, Transport Airplane Directorate, 1601 Lind Avenue SW., Renton, Washington. For information on the availability of this material at the FAA, call 425–227–1221.

Issued in Renton, Washington, on May 18, 2012.

Michael Kaszycki,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 2012–13187 Filed 5–30–12; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2012–0495; Directorate Identifier 2011–NM–236–AD]

RIN 2120–AA64

Airworthiness Directives; Gulfstream Aerospace LP (Type Certificate Previously Held by Israel Aircraft Industries, Ltd.) Airplanes

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: We propose to adopt a new airworthiness directive (AD) for certain Gulfstream Aerospace LP (Type Certificate previously held by Israel Aircraft Industries, Ltd.) Model Galaxy and Gulfstream 200 airplanes. This proposed AD was prompted by reports of degraded brake performance during landing due to improperly-sized wear indicating pins. This proposed AD would require determining the lengths of the wear indicating pins of all brake assemblies, shortening the pin if the wear indicating pin is too long, inspecting for normal brake wear, and replacing brakes with new brakes if necessary. We are proposing this AD to detect and correct improperly-sized wear indicating pins, which, if not corrected, could result in worn-out brake pads and subsequent loss of braking power, which could result in runway overruns.

DATES: We must receive comments on this proposed AD by July 16, 2012.

ADDRESSES: You may send comments by any of the following methods:

- *Federal eRulemaking Portal:* Go to *http://www.regulations.gov.* Follow the instructions for submitting comments.
- *Fax:* (202) 493–2251.
- *Mail:* U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE., Washington, DC 20590.
- *Hand Delivery:* U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE., Washington, DC between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

For service information identified in this proposed AD, contact Gulfstream Aerospace Corporation, P.O. Box 2206, Mail Station D–25, Savannah, Georgia 31402–2206; telephone 800–810–4853; fax 912–965–3520; email *pubs@gulfstream.com;* Internet *http://www.gulfstream.com/product_support/technical_pubs/pubs/index.htm.* You may review copies of the referenced service information at the FAA, Transport Airplane Directorate, 1601 Lind Avenue SW., Renton, Washington. For information on the availability of this material at the FAA, call 425–227–1221.

Examining the AD Docket

You may examine the AD docket on the Internet at *http://www.regulations.gov;* or in person at the Docket Operations office between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The AD docket contains this proposed AD, the regulatory evaluation, any comments received, and other information. The street address for the Docket Operations office (telephone (800) 647–5527) is in the **ADDRESSES** section. Comments will be available in the AD docket shortly after receipt.

FOR FURTHER INFORMATION CONTACT: Tom Groves, Aerospace Engineer, International Branch, ANM–116, Transport Airplane Directorate, FAA, 1601 Lind Avenue SW., Renton, Washington 98057–3356; telephone: (425) 227–1503; fax: (425) 227–1149.

SUPPLEMENTARY INFORMATION:

Comments Invited

We invite you to send any written relevant data, views, or arguments about this proposed AD. Send your comments to an address listed under the **ADDRESSES** section. Include ''Docket No. FAA–2012–0495; Directorate Identifier 2011–NM–236–AD'' at the beginning of your comments. We specifically invite comments on the overall regulatory, economic, environmental, and energy aspects of this proposed AD. We will consider all comments received by the closing date and may amend this proposed AD based on those comments.

We will post all comments we receive, without change, to *http://www.regulations.gov,* including any personal information you provide. We will also post a report summarizing each substantive verbal contact we receive about this proposed AD.

Discussion

The Civil Aviation Authority of Israel (CAAI), which is the aviation authority for Israel, has issued Israeli Airworthiness Directive 32–11–10–13, dated October 31, 2011 (referred to after this as ''the MCAI''), to correct an unsafe condition for the specified products. The MCAI states:

> Two G200 operators experienced degraded brake performance during landing. Subsequent investigation revealed that in both cases the brake wear pins showed remaining life, but the brakes were worn to the minimum pad thickness specified in the Brake Assembly Component Maintenance Manual (CMM). It was found out that pins of incorrect length were installed during brake assembly overhaul. When the brake pads are fully worn without indication, loss of braking power is expected, possibly causing runway overruns. This constitutes an unsafe condition.

The required action is determining the lengths of the wear indicating pins of all brake assemblies, shortening the pin if the wear indicating pin is too long, inspecting for normal brake wear, and replacing brakes with new brakes if necessary. You may obtain further information by examining the MCAI in the AD docket.

Relevant Service Information

Gulfstream Aerospace LP has issued Service Bulletin 200–32–389, Revision 1, dated October 27, 2011. The actions described in this service information are intended to correct the unsafe condition identified in the MCAI.

FAA's Determination and Requirements of This Proposed AD

This product has been approved by the aviation authority of another country, and is approved for operation in the United States. Pursuant to our bilateral agreement with the State of Design Authority, we have been notified of the unsafe condition described in the MCAI and service information referenced above. We are proposing this AD because we evaluated all pertinent information and determined an unsafe condition exists and is likely to exist or develop on other products of the same type design.

Costs of Compliance

Based on the service information, we estimate that this proposed AD would affect about 155 products of U.S. registry. We also estimate that it would take about 16 work-hours per product to comply with the basic requirements of this proposed AD. The average labor rate is $85 per work-hour. Required parts would cost about $0 per product. Where the service information lists required parts costs that are covered under warranty, we have assumed that there will be no charge for these parts. As we do not control warranty coverage for affected parties, some parties may incur costs higher than estimated here. Based on these figures, we estimate the cost of the proposed AD on U.S. operators to be $210,800, or $1,360 per product.

We have received no definitive data that would enable us to provide cost estimates for the on-condition actions specified in this proposed AD.

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 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 this 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);
3. Will not affect intrastate aviation in Alaska; and
4. 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.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Incorporation by reference, 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 FAA amends § 39.13 by adding the following new AD:

Gulfstream Aerospace LP (Type Certificate previously held by Israel Aircraft Industries, Ltd.): Docket No. FAA–2012–0495; Directorate Identifier 2011–NM–236–AD.

(a) Comments Due Date

We must receive comments by July 16, 2012.

(b) Affected ADs

None.

(c) Applicability

This AD applies to Gulfstream Aerospace LP (Type Certificate previously held by Israel Aircraft Industries, Ltd.) Model Galaxy and Gulfstream 200 airplanes, certificated in any category, serial numbers 004 through 250 inclusive.

(d) Subject

Air Transport Association (ATA) of America Code 32: Landing Gear.

(e) Reason

This AD was prompted by reports of degraded brake performance during landing due to improperly-sized wear indicating pins. We are issuing this AD to detect and correct improperly-sized wear indicating pins, which, if not corrected, could result in worn-out brake pads and subsequent loss of braking power, which could result in runway overruns.

(f) Compliance

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

(g) Determining and Correcting Pin Length and Inspecting Brake Wear

Within 40 days after the effective date of this AD, determine the length of the wear indicating pins of all the brake assemblies, in accordance with the Accomplishment Instructions of Gulfstream Service Bulletin 200–32–389, Revision 1, dated October 27, 2011.

(1) If the length of the pins is within the limits specified in Gulfstream Service Bulletin 200–32–389, Revision 1, dated October 27, 2011, before further flight, perform a normal brake wear inspection in accordance with the Accomplishment Instructions of Gulfstream Service Bulletin 200–32–389, Revision 1, dated October 27, 2011.

(2) If any wear indicating pin is too long, as specified by the limits in Gulfstream Service Bulletin 200–32–389, Revision 1, dated October 27, 2011, before further flight, shorten the pin and perform a normal brake wear inspection, in accordance with the Accomplishment Instructions of Gulfstream Service Bulletin 200–32–389, Revision 1, dated October 27, 2011.

(h) Brake Replacement

If any brake fails the wear inspection required by paragraphs (g)(1) and (g)(2) of this AD, before further flight, replace the affected brakes with new brakes, in accordance with the Accomplishment Instructions of Gulfstream Service Bulletin 200–32–389, Revision 1, dated October 27, 2011.

(i) Credit for Actions Accomplished in Accordance With Previous Service Information

This paragraph provides credit for the actions required by paragraph (g) of this AD, if those actions were performed before the effective date of this AD using the Accomplishment Instructions of Gulfstream Service Bulletin 200–32–389, dated October 20, 2011.

(j) Other FAA AD Provisions

The following provisions also apply to this AD:

(1) *Alternative Methods of Compliance (AMOCs):* The Manager, International Branch, ANM–116, Transport Airplane Directorate, FAA, has the authority to approve AMOCs for this AD, if requested using the procedures found in 14 CFR 39.19. In accordance with 14 CFR 39.19, send your request to your principal inspector or local Flight Standards District Office, as appropriate. If sending information directly to the International Branch, send it to ATTN: Tom Groves, Aerospace Engineer, International Branch, ANM–116, Transport Airplane Directorate, FAA, 1601 Lind Avenue SW., Renton, Washington 98057–3356; telephone (425) 227–1503; fax (425) 227–1149. Information may be emailed to: *9-ANM-116-AMOC-REQUESTS@faa.gov.* Before using any approved AMOC, notify your appropriate principal inspector, or lacking a principal inspector, the manager of the local flight standards district office/certificate holding district office. The AMOC approval letter must specifically reference this AD.

(2) *Airworthy Product:* For any requirement in this AD to obtain corrective actions from a manufacturer or other source, use these actions if they are FAA-approved. Corrective actions are considered FAA-approved if they are approved by the State of Design Authority (or their delegated agent). You are required to assure the product is airworthy before it is returned to service.

(k) Related Information

(1) Refer to Israeli Airworthiness Directive 32–11–10–13, dated October 31, 2011; and Gulfstream Service Bulletin 200–32–389, Revision 1, dated October 27, 2011; for related information.

(2) For service information identified in this AD, contact Gulfstream Aerospace Corporation, P.O. Box 2206, Mail Station D–25, Savannah, Georgia 31402–2206; telephone 800–810–4853; fax 912–965–3520; email pubs@gulfstream.com; Internet *http://www.gulfstream.com/product_support/technical_pubs/pubs/index.htm.* You may review copies of the referenced service information at the FAA, Transport Airplane Directorate, 1601 Lind Avenue SW., Renton, Washington. For information on the availability of this material at the FAA, call 425–227–1221.

Issued in Renton, Washington, on May 18, 2012.

Michael Kaszycki,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 2012–13194 Filed 5–30–12; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Saint Lawrence Seaway Development Corporation

33 CFR Part 401

[Docket No. SLSDC–2012–0001]

RIN 2135–AA30

Seaway Regulations and Rules: Periodic Update, Various Categories

AGENCY: Saint Lawrence Seaway Development Corporation, DOT.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Saint Lawrence Seaway Development Corporation (SLSDC) and the St. Lawrence Seaway Management Corporation (SLSMC) of Canada, under international agreement, jointly publish and presently administer the St. Lawrence Seaway Regulations and Rules (Practices and Procedures in Canada) in their respective jurisdictions. Under agreement with the SLSMC, the SLSDC is amending the joint regulations by updating the Seaway Regulations and Rules in various categories. The proposed changes will update the following sections of the Regulations and Rules: Condition of Vessels; Seaway Navigation; Dangerous Cargo; Information and Reports; General; and, Navigation Closing Procedures. These proposed amendments are necessary to take account of updated procedures and will enhance the safety of transits through the Seaway. Several of the proposed amendments are merely editorial or for clarification of existing requirements.

DATES: Any party wishing to present views on the proposed amendment may file comments with the Corporation on or before July 2, 2012.

ADDRESSES: You may submit comments identified by Docket Number SLSDC 2012–0001 by any of the following methods:

- *Web Site: http://www.Regulations.gov.* Follow the online instructions for submitting comments/submissions.
- *Fax:* 1–202–493–2251.
- *Mail:* Docket Management Facility; U.S. Department of Transportation, 1200 New Jersey Avenue SE., West Building Ground Floor, Room W12–140, Washington, DC 20590–001.
- *Hand Delivery:* Documents may be submitted by hand delivery or courier to West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE., Washington, DC 20590–001, between 9 a.m. and 5 p.m., Monday through Friday, except Federal Holidays.

Instructions: All submissions must include the agency name and docket number or Regulatory Identification Number (RIN) for this rulemaking. Note that all comments received will be posted without change at *http://www.Regulations.gov* including any personal information provided. Please see the Privacy Act heading under *Regulatory Notices.*

Docket: For access to the docket to read background documents or comments received, go to *http://www.Regulations.gov;* or in person at the Docket Management Facility; U.S.

Department of Transportation, 1200 New Jersey Avenue SE., West Building Ground Floor, Room W12–140, Washington, DC 20590–001, between 9 a.m. and 5 p.m., Monday through Friday, except Federal Holidays.

FOR FURTHER INFORMATION CONTACT: Carrie Mann Lavigne, Chief Counsel, Saint Lawrence Seaway Development Corporation, 180 Andrews Street, Massena, New York 13662; 315/764–3200.

SUPPLEMENTARY INFORMATION: The Saint Lawrence Seaway Development Corporation (SLSDC) and the St. Lawrence Seaway Management Corporation (SLSMC) of Canada, under international agreement, jointly publish and presently administer the St. Lawrence Seaway Regulations and Rules (Practices and Procedures in Canada) in their respective jurisdictions. Under agreement with the SLSMC, the SLSDC is proposing to amend the joint regulations by updating the Regulations and Rules in various categories. The proposed changes would update the following sections of the Regulations and Rules: Condition of Vessels; Seaway Navigation; Dangerous Cargo; Information and Reports; General; and, Navigation Closing Procedures. These updates are necessary to take account of updated procedures which will enhance the safety of transits through the Seaway. Many of these proposed changes are to clarify existing requirements in the regulations. Where new requirements or regulations are being proposed, an explanation for such a change is provided below.

Regulatory Notices: Privacy Act: Anyone is able to search the electronic form of all comments received into any of our dockets by the name of the individual submitting the comment (or signing the comment, if submitted 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 (Volume 65, Number 70; Pages 19477–78) or you may visit *http://www.Regulations.gov.*

The SLSDC is proposing to amend three sections of the Condition of Vessels portion of the joint Seaway regulations. Under section 401.11, ''Fairleads'', due to damage from fairleads on new vessels, the SLSDC is proposing that all sharp edges be rounded. In section 401.12, ''Minimum requirements—mooring lines and fairleads'', the SLSDC is addressing the use of wire lines on vessels 100 m or less. In section 401.15, ''Stern anchors'', the Seaway entities are proposing vessels of more than 125 m in overall length as well as every integrated tug and barge or articulated tug and barge unit greater than 125 m in overall length be equipped with a stern anchor.

Several changes to the Seaway Navigation section are being proposed. The Seaway Corporations are amending its joint rules in section 401.29, ''Maximum draft'', to permit vessels using a ''Draft Information System'' (DIS) to transit the Seaway up to 7 cm (3 inches) above the maximum permissible draft allowed at the time. The use of a DIS is an optional, not a mandatory requirement, to transit the Seaway. The DIS will allow the vessel to transit the Seaway at a draft up to 3 inches (7 cm) more than the published maximum draft with prior approval from the two Seaway entities.

Benefits of Using the DIS

The primary purpose of this proposed amendment is safety. The use of the DIS will ensure that vessels maintain a safe under keel clearance as they make maximum use of the available water column. DIS uses water level measurements, bathymetry of the channel bottom, and squat of the vessel as it moves at different speeds and in different channel types. The squat of a vessel varies depending on the vessel type, hull shape, and the type of channel in which it is operating, and the vessel's speed. By including all the factors, the under keel clearance value is determined in real time. The information on the projected under keel clearance is integrated electronically with chart data, high-resolution bathymetry and other readings on a single bridge display.

The technology features an algorithm, which allows the Master to estimate under keel clearance ahead, offering time for a course change or other required reaction in transit. By Masters having more precise information regarding the available water column, the risk of a vessel touching bottom or grounding is reduced.

In addition to the safety benefits, increasing the maximum allowable draft will increase the Seaway's productivity and competitiveness. Depending on the commodity carried, an additional three inches of draft might account for as much as 360 additional metric tons per voyage.

Development of DIS Specification

The use of a DIS tool began in 2003 in the St. Mary's River. In 2006, the Seaway entities conducted 4 trials of the tool used in the St. Mary's River as a proof of concept. Three tests were conducted in the Montreal to Lake Ontario (MLO) section of the Seaway during 2007 under low water conditions. During 2008 tests were conducted in the MLO and Welland Canal sections of the Seaway. In 2009, eight (8) trials were conducted in the Welland Canal section and ten (10) trials were conducted in the MLO section of the Seaway. In 2010 a DIS pilot program was instituted in the MLO and Welland Canal. After successful completion of the test trials and pilot program and to ensure future consistency and reliability of the DIS, the two Seaway entities began the development of a standard DIS specification.

On January 19, 2011, the two Seaway Corporations jointly published an industrial implementation specification entitled, ''Implementation Specification—a Draft Information System for the St. Lawrence Seaway'' (Specification). Following a public comment period during which comments received were considered in the development of the Specification, a final Implementation Specification was published on the bi-national Web site at *http://www.greatlakes-seaway.com* on March 16, 2011. The Specification was developed under the guidance of the St. Lawrence Seaway Management Corporation, the SLSDC, together with representatives from system manufacturers and the shipping industry. The development of the Specification followed accelerated procedures derived from the International Organization for Standards (ISO) standardization process that endeavored to develop a broad based consensus standard. The DIS Implementation Specification describes the functionality and interfaces for a system which utilizes water levels, channel type, bathymetry, and vessel speed and characteristics to determine current and predicted under keel clearance. On March 18, 2012, the first DIS Tool was verified by a member of the International Association of Classification Societies (IACS) to be compliant with the Specification.

In addition, the two Seaway Corporations, in section 401.32, ''Cargo booms—deck cargo'' are proposing to require notification of the height of deck cargo in order to determine appropriate wind restrictions.

In the Information and Reports section, a change to section 401.79, ''Advance notice of arrival, vessels requiring inspection'' is being proposed. The amendments would provide requirements for reporting notice of arrival depending on the vessel's voyage time. Further, vessels requiring inspection or re-inspection would be required to provide a 24-hour notice of inspection based on certain specified factors. The Advance Notice of Arrival procedures are currently in effect pursuant to Seaway Notices.

The other changes to the joint regulations are merely editorial or to clarify existing requirements.

Regulatory Evaluation

This proposed regulation involves a foreign affairs function of the United States and therefore Executive Order 12866 does not apply and evaluation under the Department of Transportation's Regulatory Policies and Procedures is not required.

Regulatory Flexibility Act Determination

I certify that this proposed regulation will not have a significant economic impact on a substantial number of small entities. The St. Lawrence Seaway Regulations and Rules primarily relate to commercial users of the Seaway, the vast majority of whom are foreign vessel operators. Therefore, any resulting costs will be borne mostly by foreign vessels.

Environmental Impact

This proposed regulation does not require an environmental impact statement under the National Environmental Policy Act (49 U.S.C. 4321, et seq.) because it is not a major federal action significantly affecting the quality of the human environment.

Federalism

The Corporation has analyzed this proposed rule under the principles and criteria in Executive Order 13132, dated August 4, 1999, and has determined that this proposal does not have sufficient federalism implications to warrant a Federalism Assessment.

Unfunded Mandates

The Corporation has analyzed this proposed rule under Title II of the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4, 109 Stat. 48) and determined that it does not impose unfunded mandates on State, local, and tribal governments and the private sector requiring a written statement of economic and regulatory alternatives.

Paperwork Reduction Act

This proposed regulation has been analyzed under the Paperwork Reduction Act of 1995 and does not contain new or modified information collection requirements subject to the Office of Management and Budget review.

List of Subjects in 33 CFR Part 401

Hazardous materials transportation, Navigation (water), Penalties, Radio, Reporting and recordkeeping requirements, Vessels, Waterways.

Accordingly, the Saint Lawrence Seaway Development Corporation proposes to amend 33 CFR part 401as follows:

PART 401—SEAWAY REGULATIONS AND RULES

Subpart A—Regulations

1. The authority citation for subpart A of part 401 continues to read as follows:

Authority: 33 U.S.C. 983(a) and 984(a)(4), as amended; 49 CFR 1.52, unless otherwise noted.

2. In § 401.11, add paragraph (a)(4) to read as follows:

§ 401.11 Fairleads.

(a) * * *

(4) When passing synthetic lines through a type of fairlead or closed chock acceptable to the Manager and the Corporation all sharp edges of the fairlead, closed chock and/or bulwark shall be rounded to protect the line from chafing or breakage.

* * * * *

3. In § 401.12 revise paragraph (a)(1)(ii) to read as follows:

§ 401.12 Minimum requirements—mooring lines and fairleads.

(a) * * *

(1) * * *

(ii) One synthetic hawser may be hand held or if wire line is used shall be powered. The line shall lead astern from the break of the bow through a closed chock to suitable bitts on deck for synthetic line or led from a capstan, winch drum or windlass to an approved fairlead for a wire line.

* * * * *

4. Revise § 401.15 to read as follows:

§ 401.15 Stern anchors.

(a) Every vessel of more than 125 m in overall length, the keel of which is laid after January 1, 1975, shall be equipped with a stern anchor.

(b) Every integrated tug and barge or articulated tug and barge unit greater than 125 m in overall length which is constructed after January 1, 2003 shall be equipped with a stern anchor.

5. In § 401.28 revise paragraph (d) to read as follows:

§ 401.28 Speed limits.

* * * * *

(d) Notwithstanding the above speed limits, every vessel approaching a free standing lift bridge shall proceed at a speed that it will be able to stop prior to it reaching the Limit of Approach sign should the raising of the bridge be delayed.

* * * * *

6. Revise § 401.29 to read as follows:

§ 401.29 Maximum draft.

(a) Notwithstanding any provision herein, the loading of cargo, draft and speed of a vessel in transit shall be controlled by the master, who shall take into account the vessel's individual characteristics and its tendency to list or squat, so as to avoid striking bottom.[1]

(b) The draft of a vessel shall not, in any case, exceed 79.2 dm or the maximum permissible draft designated in a Seaway Notice by the Manager and the Corporation for the part of the Seaway in which a vessel is passing.

(c) Any vessel equipped with:

(1) An operational Draft Information System (DIS) Tool verified by a member of the International Association of Classification Societies (IACS) as compliant with the Implementation Specifications found at *http://www.greatlakes-seaway.com* and contained in the Seaway Handbook under ''Ship Transit and Equipment Requirements'' shall have onboard;

(2) Up-to-date electronic navigational charts; and

(3) Up-to-date charts containing high-resolution bathymetric data; and

(4) A pilot plug, if using a portable DIS Tool, will be permitted, when using the DIS Tool, subject to 33 CFR 29(a), to increase their draft by no more than 7 cm above the maximum permissible draft prescribed under 33 CFR 29(b) in effect at the time.

(d) Any vessel intending to use DIS must notify the Manager or the Corporation in writing at least 24-hours prior to commencement of its initial transit in the System with the DIS Tool.

(e) Verification document of the DIS Tool must be kept on board the vessel at all times and made available for inspection.

(f) If for any reason the DIS becomes inoperable, malfunctions, or is not used, the vessel must notify the Manager or the Corporation immediately.

(68 Stat. 93–96, 33 U.S.C. 981–990, as amended and secs. 4, 5, 6, 7, 8, 12 and 13 of Sec. 2 of Pub. L. 95–474, 92 Stat. 1471)

7. In § 401.32 add paragraph (b)(3) to read as follows:

§ 401.32 Cargo booms-deck cargo.

* * * * *

(b) * * *

(3) Seaway Traffic Control Center shall be notified of the height of deck cargo prior to transiting the Seaway or

[1] The main channels between the Port of Montreal and Lake Erie have a controlling depth of 8.23m.

when departing from a Port or Wharf within the Seaway.

8. In § 401.44, revise paragraph (b) to read as follows:

§ 401.44 Mooring in locks.

* * * * *

(b) Once the mooring lines are on the mooring posts, lines shall be kept slack until the ''all clear'' signal is given by the lock personnel. When casting off signal is received, mooring lines should be kept slack until the ''all clear'' signal is given by the lock personnel.

9. In § 401.59, add paragraph (e) to read as follows:

§ 401.59 Pollution.

* * * * *

(e) Except as authorized by the Manager or the Corporation, no over the side painting shall be allowed in the Seaway.

* * * * *

10. In § 401.72, revise paragraph (d) to read as follows:

§ 401.72 Reporting—explosive and hazardous cargo vessels.

* * * * *

(d) Every vessel carrying radioactive substances shall, when reporting in, give the number and date of issue of any required certificate issued by the Canadian Nuclear Safety Commission (CNSC) and/or the U.S. Nuclear Regulatory Commission (USNRC) authorizing such shipment.

* * * * *

11. Revise § 401.79 to read as follows:

§ 401.79 Advance notice of arrival, vessels requiring inspection.

(a) *Advance Notice of Arrival.* All foreign flagged vessels intending to transit the Seaway shall submit one complete electronic Notice of Arrival (NOA) prior to entering at call in point 2 (CIP 2) as follows:

(1) If your voyage time to CIP 2 is *96 hours or more,* you must submit an electronic NOA *96 hours* before entering the Seaway at CIP 2.

(2) If your voyage time to CIP 2 is *less than 96 hours,* you must submit an electronic NOA before departure, but at least *24 hours* before entering the Seaway at CIP 2.

(3) If there are changes to the electronic NOA, submit them as soon as practicable but at least 12 hours before entering the Seaway at CIP 2.

(4) The NOA must be provided electronically following the USCG National Vessel Movement Center's (NVMC) procedures (*http://www.nvmc.uscg.gov*).

(5) To complete the NOA correctly for Seaway entry, select the following:

(i) ''CIP 2'' as the Arrival Port,

(ii) ''Foreign to Saint Lawrence Seaway'' as the Voyage Type, and

(iii) ''Saint Lawrence Seaway Transit'' as the Arrival State, City and Receiving Facility.

(b) *Vessels requiring inspection or reinspection.* All pre-cleared vessels must provide a 24 hour notice of inspection as follows:

(1) *Enhanced Seaway inspection.* All foreign flagged vessels and vessels of unusual design are subject to a Seaway inspection prior to initial transit of the Seaway each navigation season.

(2) *Inland self-inspection.* Inland domestic vessels which are approved by the Seaway and are ISM certified and have a company quality management system, must submit the ''Self-Inspection Report'', every 2 navigation seasons and not later than 30 days after ''fit out''.

(3) Inland domestic vessels not participating in the ''Self-Inspection Program'' are subject to Seaway inspection prior to every transit of the Seaway.

(4) Tub/barge combinations not on the ''Seaway Approved Tow'' list are subject to Seaway inspection prior to every transit of the Seaway.

12. In § 401. 84, revise paragraph (c) to read as follows:

§ 401.84 Reporting of impairment or other hazard by vessels transiting within the Seaway.

* * * * *

(c) Any malfunction of equipment on the vessel

* * * * *

13. In § 401.89, add paragraph (a)(4) to read as follows:

§ 401.89 Transit refused.

(a) * * *

(4) The vessel is not in compliance with flag state and/or classification society regulations.

14. Revise § 401.92 to read as follows:

§ 401.92 Wintering and laying-up.

No vessel shall winter within the Seaway or lay-up within the Seaway during the navigation season except with the written permission of the Manager or the Corporation and subject to the conditions and charges that may be imposed.

15. In Schedule II to Subpart A of Part 401—Table of Speeds, revise section number 2 to read as follows:

SCHEDULE II TO SUBPART A OF PART 401—TABLE OF SPEEDS [1]

Column I—FROM	Column II—TO	Maximum speed over the bottom (knots)	
		Column III	Column IV
* *	* *	* *	*
2. Lake St. Louis	Lower Entrance	12 (dnb)	11(upb)
Buoy A13	Lower Beauharnois Lock	14 (upb)	13(dnb)
* *	* *	* *	*

[1] Maximum speeds at which a vessel may travel in the identified area in both normal and high water conditions are set out in this schedule. The Manager and the Corporation will, from time to time, designate the set of speed limits that is in effect.

Issued at Washington, DC, on May 21, 2012.

Saint Lawrence Seaway Development Corporation.

Craig H. Middlebrook,

Acting Administrator.

[FR Doc. 2012–12987 Filed 5–30–12; 8:45 am]

BILLING CODE 4910–61–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 62

[EPA–R05–OAR–2012–0312; FRL–9679–5]

Approval of Negative Declaration and Withdrawal of Large Municipal Waste Combustors State Plan for Designated Facilities and Pollutants: Illinois

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: EPA is proposing to approve Illinois' negative declaration and request for EPA withdrawal of its 111(d)/129 State Plan to control air pollutants from ''Large Municipal Waste Combustors'' (LMWC). On February 1, 2012, the Illinois Environmental Protection Agency submitted a letter of certification to EPA that the only designated facility in the State Plan ceased operation and is completely shut down and requested that EPA withdraw the State Plan implementing the emission guidelines for LMWCs.

DATES: Comments must be received on or before July 2, 2012.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–R05–OAR–2012–0312, by one of the following methods:

• *www.regulations.gov:* Follow the on-line instructions for submitting comments.

• *Email: nash.carlton@epa.gov.*

• *Fax:* (312) 692–2543.

• *Mail:* Carlton T. Nash, Chief, Toxics and Global Atmosphere Section, Air Toxics and Assessment Branch (AT–18J), U.S. Environmental Protection Agency, 77 West Jackson Boulevard, Chicago, Illinois 60604.

• *Hand Delivery:* Carlton T. Nash, Chief, Toxics and Global Atmosphere Section, Air Toxics and Assessment Branch (AT–18J), U.S. Environmental Protection Agency, 77 West Jackson Boulevard, Chicago, Illinois 60604. Such deliveries are only accepted during the Regional Office normal hours of operation, and special arrangements should be made for deliveries of boxed information. The Regional Office official hours of business are Monday through Friday, 8:30 a.m. to 4:30 p.m. excluding Federal holidays.

Please see the direct final rule which is located in the Rules section of this **Federal Register** for detailed instructions on how to submit comments.

FOR FURTHER INFORMATION CONTACT: Margaret Sieffert, Environmental Engineer, Environmental Protection Agency, Region 5, 77 West Jackson Boulevard (AT–18J), Chicago, Illinois 60604, (312) 353–1151, *sieffert.margaret@epa.gov.*

SUPPLEMENTARY INFORMATION: In the Rules section of this **Federal Register,** EPA is approving the State's submittal as a direct final rule without prior proposal because the Agency views this as a noncontroversial submittal and anticipates no adverse comments. A detailed rationale for the approval is set forth in the direct final rule. If no adverse comments are received in response to this rule, no further activity is contemplated. If EPA receives adverse comments, the direct final rule will be withdrawn and all public comments received will be addressed in a subsequent final rule based on this proposed rule. EPA will not institute a second comment period. Any parties interested in commenting on this action should do so at this time. Please note that if EPA receives adverse comment on an amendment, paragraph, or section of this rule and if that provision may be severed from the remainder of the rule, EPA may adopt as final those provisions of the rule that are not the subject of an adverse comment. For additional information, see the direct final rule which is located in the Rules section of this **Federal Register.**

Dated: May 16, 2012.

Susan Hedman,

Regional Administrator, Region 5.

[FR Doc. 2012–13204 Filed 5–30–12; 8:45 am]

BILLING CODE 6560–50–P

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Part 73

[MB Docket No. 99–25; Report No. 2950]

Petitions for Reconsideration of Action of Rulemaking Proceeding

AGENCY: Federal Communications Commission.

ACTION: Petition for reconsideration.

SUMMARY: In this document, Petitions for Reconsideration (Petitions) have been filed in the Commission's Rulemaking proceeding against the adoption of a national cap of 50 applications and a market-based cap of one application per applicant per market for pending Auction No. 83 translator applications.

DATES: Oppositions to the Petition must be filed on or before June 15, 2012. Replies to an opposition must be filed on or before June 25, 2012.

ADDRESSES: Federal Communications Commission, 445 12th Street SW., Washington, DC 20554.

FOR FUTHER INFORMATION CONTACT: Kelly Donohue, Media Bureau, 202–418–8192.

SUPPLEMENTARY INFORMATION: This is a summary of Commission's document, Report No. 2950, released May 24, 2012. The full text of this document is available for viewing and copying in Room CY–B402, 445 12th Street SW., Washington, DC or may be purchased from the Commission's copy contractor, Best Copy and Printing, Inc. (BCPI) (1–800–378–3160). The Commission will not send a copy of this *Notice* pursuant to the Congressional Review Act, 5 U.S.C. 801(a)(1)(A), because this *Notice* does not have an impact on any rules of particular applicability.

Subject: Creation of a Low Power Radio Service, published at 77 FR 21002, April 9, 2012, in MB Docket No. 99–25, and published pursuant to 47 CFR 1.429(e). *See* 1.4(b)(1) of the Commission's rules (47 CFR 1.4(b)(1)).

Number of Petitions Filed: 5.

Federal Communications Commission.

Marlene H. Dortch,

Secretary, Office of the Secretary, Office of Managing Director.

[FR Doc. 2012–13152 Filed 5–30–12; 8:45 am]

BILLING CODE 6712–01–P

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

50 CFR Part 17

[FWS–R1–ES–2011–0096; 4500030114]

RIN 1018–AX38

Endangered and Threatened Wildlife and Plants; Designation of Critical Habitat for the Southern Selkirk Mountains Population of Woodland Caribou (Rangifer tarandus caribou)

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Proposed rule; availability of supplementary documents and announcement of public hearing.

SUMMARY: We, the U.S. Fish and Wildlife Service (Service), announce the

reopening of the comment period on our November 30, 2011, proposed rule to designate critical habitat for the southern Selkirk Mountains population of woodland caribou (*Rangifer tarandus caribou*) under the Endangered Species Act of 1973, as amended (Act). We also announce the availability of a draft economic analysis of the proposed designation and an amended required determinations section of the proposal. We are reopening the comment period to allow all interested parties an opportunity to comment simultaneously on the proposed rule, the associated draft economic analysis, and the amended required determinations section. We will also hold a public informational session and hearing (see **DATES** and **ADDRESSES**).

DATES: *Written Comments:* We will consider comments received or postmarked on or before July 2, 2012. Comments must be received by 11:59 p.m. Eastern Time on the closing date.

Public informational session and public hearing: We will hold a public informational session from 9:30 a.m. to 11 a.m., followed by a public hearing from 2 p.m. to 5 p.m., on June 16, 2012, in Coolin, Idaho. Speaker registration will begin at 1 p.m. (see **ADDRESSES**).

ADDRESSES:

Document availability: You may obtain copies of the proposed rule and the draft economic analysis on the internet at *http://www.regulations.gov* at Docket No. FWS–R1–ES–2011–0096 or by mail from the Idaho Fish and Wildlife Office (see **FOR FURTHER INFORMATION CONTACT**).

Written Comments: You may submit comments by one of the following methods:

(1) *Federal eRulemaking Portal: http://www.regulations.gov.* In the Search box, enter the docket number for this proposed rule, which is FWS–R1–ES–2011–0096. Please ensure that you have found the correct rulemaking before submitting your comment.

(2) *U.S. mail or hand delivery:* Public Comments Processing, Attn: FWS–R1–ES–2011–0096; Division of Policy and Directives Management; U.S. Fish and Wildlife Service; 4401 N. Fairfax Drive, MS 2042–PDM; Arlington, VA 22203.

We request that you send comments only by the methods described above. We will post all comments on *http://www.regulations.gov.* This generally means that we will post any personal information you provide us (see the Public Comments section below for more information).

Public informational session and public hearing: The public informational session and hearing will be held at The Inn at Priest Lake, 5310 Dickensheet Highway, Coolin, Idaho 83821. People needing reasonable accommodations in order to attend and participate in the public hearing should contact Brian Kelly, State Supervisor, Idaho Fish and Wildlife Office, as soon as possible (see **FOR FURTHER INFORMATION CONTACT**).

FOR FURTHER INFORMATION CONTACT: Brian Kelly, State Supervisor, Idaho Fish and Wildlife Office, 1387 S. Vinnell Way, Room 368, Boise, ID 83709; telephone 208–378–5243; facsimile 208–378–5262. Persons who use a telecommunications device for the deaf (TDD) may call the Federal Information Relay Service (FIRS) at 800–877–8339.

SUPPLEMENTARY INFORMATION:

Public Comments

We will accept written comments and information during this reopened comment period on our proposed critical habitat for the southern Selkirk Mountains population of woodland caribou that was published in the **Federal Register** on November 30, 2011 (76 FR 74018), our draft economic analysis of the proposed designation, and the amended required determinations provided in this document. We will consider information and recommendations from all interested parties. We are particularly interested in comments concerning:

(1) The reasons why we should or should not designate habitat as ''critical habitat'' under section 4 of the Act (16 U.S.C. 1531 *et seq.*), including information on any threats to the southern Selkirk Mountains population of woodland caribou from human activity, the degree of which can be expected to increase due to the designation, such that the designation of critical habitat may not be prudent.

(2) Specific information on:

(a) The amount and distribution of habitat for the southern Selkirk Mountains population of woodland caribou in the United States.

(b) What areas which were occupied at the time of listing and contain the physical and biological features essential to the conservation of the species should be included in the designation and why.

(c) What areas outside the geographical area occupied at the time of listing are essential for the conservation of the species and why.

(d) Special management considerations or protections that may be required for the physical or biological features essential to the conservation of the southern Selkirk Mountains population of woodland caribou that have been identified in this proposal, including management for the potential effects of climate change.

(3) Land use designations and current or planned activities in the subject areas and their possible impacts on the proposed critical habitat.

(4) Any reasonably foreseeable economic, national security, or other relevant impacts of the proposed critical habitat designation. We are particularly interested in any impacts on small entities or families, and the benefits of including or excluding areas that exhibit these impacts.

(5) Whether any specific areas we are proposing for critical habitat designation should be considered for exclusion under section 4(b)(2) of the Act, and whether the benefits of potentially excluding any specific area outweigh the benefits of including that area under section 4(b)(2) of the Act, and why.

(6) Whether we could improve or modify our approach to designating critical habitat in any way to provide for greater public participation and understanding, or to better accommodate public concerns and comments.

(7) Information on the extent to which the description of economic impacts in the draft economic analysis is complete and accurate.

(8) The likelihood of adverse social reactions to the designation of critical habitat, as discussed in the draft economic analysis, and how the consequences of such reactions, if likely to occur, would relate to the conservation and regulatory benefits of the proposed critical habitat designation.

Public Informational Session and Public Hearing

Section 4(b)(5)(E) of the Act requires that we hold one public hearing on a proposed regulation, if any person files a request for such a hearing within 45 days after the date of publication of a general notice. At the request of the Governor of Idaho and the Commissioners of Boundary County, Idaho, we held an informational session (a brief presentation about the proposed rule with a question-and-answer period), and a public hearing on April 28, 2012, in Bonners Ferry, Idaho (77 FR 16512; March 21, 2012). With this notice, we are announcing an additional informational session and public hearing (see **DATES** and **ADDRESSES**). Anyone wishing to make an oral statement at the public hearing for the record is encouraged to provide a written copy of their statement to us at the hearing. In the event there is a large attendance, the time allotted for oral statements may be limited. Speakers can sign up at the informational meeting and hearing if they desire to make an oral statement. Oral and written statements receive equal consideration at the hearing. There are no limits on the length of written comments submitted to us. If you have any questions concerning the public hearing, please contact Brian Kelly, State Supervisor, Idaho Fish and Wildlife Office (see **FOR FURTHER INFORMATION CONTACT**).

The Service has conducted several outreach efforts to be responsive to public requests for additional information. On January 9, 2012, we presented information on the proposed critical habitat designation in Bonners Ferry, Boundary County, Idaho, at the request of the Kootenai Valley Resource Initiative (KVRI), and on January 24, 2012, we held an informational meeting in Priest Lake, at the request of the Bonner County Idaho Commission. On February 13, 2012, we participated in a meeting in Boundary County, Idaho, sponsored by the KVRI. On February 28, 2012, and March 26, 2012, we participated in meetings with the Bonner County Idaho Commission, and on April 19, 2012, we participated in a meeting with the Boundary County Idaho Commission. All meetings were open to the public.

Our final determination concerning critical habitat for the southern Selkirk Mountains population of woodland caribou will take into consideration all written comments we receive during the comment periods, comments from peer reviewers, comments and public testimony received during the public hearings, and all information we receive in response to the draft economic analysis. All public comments will be included in the public record for this rulemaking. On the basis of public comments, we may, during the development of our final determination, find that areas within the proposed designation do not meet the definition of critical habitat, that some modifications to the described boundaries are appropriate, or that areas may or may not be appropriate for exclusion under section 4(b)(2) of the Act.

If you previously submitted comments or information on this proposed rule, please do not resubmit them. We have incorporated them into the public record, and will fully consider them in the preparation of our final determination.

You may submit your comments and materials concerning our proposed rule or draft economic analysis by one of the methods listed in **ADDRESSES**.

We will post your entire comment—including any personal identifying information—on *http://www.regulations.gov.* If you provide personal identifying information, such as your street address, phone number, or email address, you may request at the top of your document that we withhold this information from public review. However, we cannot guarantee that we will be able to do so. Please include sufficient information with your comments to allow us to verify any scientific or commercial information you include.

Comments and materials we receive, as well as supporting documentation we used in preparing the proposed rule and draft economic analysis, will be available for public inspection on *http://www.regulations.gov,* or by appointment, during normal business hours, at the U.S. Fish and Wildlife Service, Idaho Fish and Wildlife Office (see **FOR FURTHER INFORMATION CONTACT**). You may obtain copies of the proposed rule and the draft economic analysis on the Internet at *http://www.regulations.gov* at Docket Number FWS–R1–ES–2011–0096, or by mail from the Idaho Fish and Wildlife Office (see **FOR FURTHER INFORMATION CONTACT**).

Background

It is our intent to discuss only those topics directly relevant to the designate of critical habitat for the southern Selkirk Mountains population of woodland caribou. For a description of the previous Federal actions concerning the southern Selkirk Mountains population of woodland caribou, please refer to the proposed critical habitat rule, as described below.

Previous Federal Actions

On November 30, 2011 (76 FR 74108), we published a proposed rule to designate critical habitat for the southern Selkirk Mountains population of woodland caribou. We proposed to designate as critical habitat approximately 375,562 acres (ac) (151,985 hectares (ha)) in a single unit (with two subunits) in Boundary and Bonner counties in Idaho, and Pend Oreille County in Washington. That proposal had a 60-day comment period, ending on January 30, 2012. On March 21, 2012 (77 FR 16512), we reopened the comment period for an additional 60 days, and we conducted a public informational session and public hearing on April 28, 2012, in Bonners Ferry, Idaho, at the request of the Governor of Idaho and the Bonner County, Idaho, Commissioners.

Critical Habitat

Section 3 of the Act defines critical habitat as the specific areas within the geographical area occupied by a species, at the time it is listed in accordance with the provisions of section 4 of the Act, on which are found those physical or biological features essential to the conservation of the species and which may require special management considerations or protection, and specific areas outside the geographical area occupied by a species at the time it is listed, upon a determination by the Secretary that such areas are essential for the conservation of the species. If the proposed rule is made final, section 7(a)(2) of the Act will prohibit destruction or adverse modification of critical habitat by any activity funded, authorized, or carried out by any Federal agency. Federal agencies proposing actions that may affect critical habitat must consult with us on the effects of their proposed actions pursuant to the requirements of section 7(a)(2) of the Act.

Consideration of Impacts Under Section 4(b)(2) of the Act

Section 4(b)(2) of the Act requires that we designate or revise critical habitat based upon the best scientific data available, and after taking into consideration the economic impact, the impact on national security, and any other relevant impact of specifying any particular area as critical habitat. The Secretary may exclude an area from critical habitat if he determines that the benefits of such exclusion outweigh the benefits of specifying such area as part of the critical habitat, unless he determines, based on the best scientific and commercial data available, that failure to designate such area will result in the extinction of the species concerned.

When considering the benefits of inclusion for an area, we consider the additional regulatory benefits that area would receive from the protection from adverse modification or destruction as a result of actions with a Federal nexus (activities conducted, funded, permitted, or authorized by Federal agencies), the educational benefits of mapping areas containing essential features that aid in the recovery of the listed species, and any benefits that may result from designation due to State or Federal laws that may apply to critical habitat.

When considering the benefits of exclusion, we consider, among other things, whether exclusion of a specific area is likely to result in conservation; the continuation, strengthening, or encouragement of partnerships; or implementation of a management plan. In the case of the southern Selkirk Mountains population of woodland caribou, the benefits of critical habitat include public awareness of the presence of the species and the importance of habitat protection, and, where a Federal nexus exists, increased habitat protection for the species due to protection from adverse modification or destruction of critical habitat. In practice, situations with a Federal nexus exist primarily on Federal lands or for projects undertaken by, or with the authorization or permission of, Federal agencies.

We have not proposed to exclude any areas from critical habitat. However, the final decision on whether to exclude any areas will be based on the best available scientific and commercial data available, information obtained during the comment period concerning economic impacts, impacts to national security, or any other relevant impacts of the proposed designation. With regard to economic impacts, we have prepared a draft economic analysis concerning the proposed critical habitat designation, which is available for review and comment (see **ADDRESSES**).

Draft Economic Analysis

The purpose of the draft economic analysis is to identify and analyze the reasonably foreseeable potential economic impacts associated with the proposed critical habitat designation for the southern Selkirk Mountains population of woodland caribou. The draft economic analysis describes the economic impacts of all potential conservation efforts for the species; some of these costs will likely be incurred regardless of whether we designate critical habitat. The economic impact of the proposed critical habitat designation is analyzed by comparing scenarios both ''with critical habitat'' and ''without critical habitat.'' The ''without critical habitat'' scenario represents the baseline for the analysis, considering protections already in place for the species (e.g., under the Federal listing and other Federal or State regulations). The baseline, therefore, represents the costs incurred regardless of whether critical habitat is designated. The ''with critical habitat'' scenario describes the incremental impacts associated specifically with the designation of critical habitat for the species. In other words, these incremental impacts would not occur but for the designation. These incremental impacts produce the costs that we consider in the final designation of critical habitat when evaluating the benefits of excluding particular areas under section 4(b)(2) of the Act. The analysis looks retrospectively at baseline impacts incurred since the species was listed, and forecasts incremental impacts likely to occur if we finalize the proposed critical habitat designation.

As described above, the draft economic analysis separates conservation measures into two distinct categories according to ''without critical habitat'' and ''with critical habitat'' scenarios. Conservation measures implemented under the baseline (without critical habitat) scenario are described qualitatively within the draft economic analysis, but economic impacts associated with these measures are not quantified. Economic impacts are only quantified for conservation measures implemented specifically due to the designation of critical habitat (i.e., incremental impacts). For a further description of the methodology of the analysis, see Chapter 2, ''Framework for the Analysis,'' of the draft economic analysis.

The draft economic analysis provides estimated costs of the foreseeable potential economic impacts of the proposed critical habitat designation for the southern Selkirk Mountains population of woodland caribou over the next 20 years, from 2012 through 2031. We determined that this 20-year timeframe was the appropriate period for analysis because the availability of land-use planning information becomes very limited for most activities beyond that timeframe. The draft economic analysis identifies potential incremental costs as a result of the proposed critical habitat designation; these are those costs attributed to critical habitat over and above those baseline costs attributed to listing and other regulatory protections. The draft economic analysis quantifies economic impacts of the southern Selkirk Mountains population of woodland caribou conservation efforts associated with the following categories of activity: (1) Timber harvest; (2) fire, fire suppression, and forest management practices; (3) transportation and electricity projects; (4) mining; and (5) recreational activities.

The primary long-term threat to the southern Selkirk Mountains population of woodland caribou is the ongoing loss and fragmentation of contiguous old growth forests and forest habitats due to a combination of timber harvest, wildfires, and human activities that involve road development. The effects to woodland caribou associated with habitat loss and fragmentation are: (1) Reduction of the amount of space available for caribou, limiting the ecological carrying capacity; (2) reduction of the arboreal lichen supply, which is the caribou's key winter food source; (3) potential impacts to caribou movement patterns; (4) potential effects to the caribou's use of remaining fragmented habitat because suitable habitat parcels will be smaller and discontinuous; and (5) increased susceptibility of caribou to predation as available habitat is compressed and fragmented (Stevenson *et al.* 2001, p. 10; MCTAC 2002, pp. 20–22; Cichowski *et al.* 2004, pp. 10, 19–20; Apps and McLellan 2006, pp. 92–93; Wittmer *et al.* 2007, pp. 576–577).

Approximately 79 percent of the proposed critical habitat area is on Federal land, most of which is managed by the U.S. Forest Service (USFS). The Bureau of Land Management (BLM) manages 231 ac (93 ha) of the proposed critical habitat as a wilderness study area and for grizzly bear conservation, and approximately 294,716 ac, (119,065 ha) are managed by the USFS. National Forest lands involved in the proposed designation include the Idaho Panhandle National Forests (IPNF) in Idaho and Washington, and Colville National Forest (CNF) in Washington. Land and resource management plans (LRMPs) for the IPNF and CNF have been revised to incorporate management objectives and standards to address the above identified threats to the southern Selkirk Mountains population of woodland caribou, as a result of section 7 consultation between the Service and USFS (USFWS 2001a, b). Standards for management of habitat for the southern Selkirk Mountains population of woodland caribou were incorporated into the IPNF's 1987 and CNF's 1988 LRMP, to avoid the likelihood of jeopardizing the continued existence of the species, to contribute to caribou conservation, and to ensure consideration of the biological needs of the species during forest management planning and implementation actions (USFS 1987, pp. II–6, II–27, Appendix N; USFS 1988, pp. 4–10—4–17, 4–38, 4–42, 4–73—4–76, Appendix I). A review of our section 7 consultation records with the USFS indicates that no project modifications have been required to date, because the activities were either not within habitat for the southern Selkirk Mountains population of woodland caribou, or conservation measures were already incorporated into project designs to avoid impacts to the species or its habitat.

Of the remaining 21 percent of the proposed critical habitat designation, 17 percent (65,218 ac, 26,393 ha) is State land, and 4 percent (15,379 ac, 6,225 ha) covers privately owned lands. The draft economic analysis concludes that critical habitat designation may affect timber harvest on private lands if Federal permits to use USFS roads are required, but estimates few additional costs associated with the implementation of other activities within the proposed critical habitat area. We believe activities on State or private lands are unlikely to have a Federal nexus or be subject to section 7 consultation, based on a review of our consultation records to date. However, the draft economic analysis includes a highly conservative estimate of potential administrative costs related to section 7 consultation on non-Federal lands, by assuming that almost all activities on non-Federal land would have a Federal nexus, and those lands would be subject to timber harvest over the next 20 years. The draft economic analysis, therefore, presents a worst-case scenario with regard to economic impacts to non-Federal lands. However, there is no information available to the Service that would indicate either of the above presumptions is reasonably foreseeable, and those estimates are included solely to provide additional perspective to reviewers regarding the potential economic impacts of the proposed critical habitat designation.

Due to the extensive existing baseline protections for caribou and other listed species (grizzly bear (*Ursus arctos horribilis*), Canada lynx (*Lynx canadensis*), and bull trout (*Salvelinus confluentus*)), the incremental impacts of critical habitat designation would be limited to Federal agency (primarily USFS) administrative costs of considering adverse modification during section 7 consultation with the Service (about 19 percent of total forecast costs) as well as incremental costs for timber harvesting on private lands, including time delays in harvesting (about 81 percent of total forecast costs). For small entities (private land owners, which comprise approximately 10 percent of the private land in the area proposed for designation), the draft economic analysis estimates incremental impacts to be $30,300 annually, or $343,000 over a 20-year period based on the present value discounted at seven percent. This estimated cost would be associated with potential reductions in timber harvest due to time delays affecting privately owned forest land controlled by small entities, if they were to occur. However, we have no available information which would indicate delays are probable or reasonably foreseeable. Forest Capital Partners, LLC, which owns 90 percent of the private land within the area proposed for designation, is not considered a small entity. The total incremental costs (including Federal, State, and private lands) are estimated to be $132,000 annually, or $1.5 million over a 20-year period, based on the present value discounted at seven percent.

The proposed critical habitat designation is unlikely to generate economic impacts beyond administrative costs of section 7 consultation associated with the adverse modification analysis. Further, project proponents and land managers are aware of the species' presence throughout its range, and the need to consult with the Service for projects that have a Federal nexus that may affect the species. In conclusion, we have no information that would indicate the proposed designation of critical habitat for the southern Selkirk Mountains population of woodland caribou would change the outcome of future section 7 consultations. Any conservation measures implemented to minimize impacts to the species would very likely be sufficient to also minimize impacts to critical habitat. Therefore, we do not believe any additional conservation measures would be needed solely to minimize impacts to critical habitat.

We are soliciting data and comments from the public on the draft economic analysis, as well as all aspects of the proposed rule and our amended required determinations. We may revise the proposed rule or supporting documents to incorporate or address information we receive during the public comment period. In particular, we may exclude an area from critical habitat if we determine that the benefits of excluding the area outweigh the benefits of including the area, provided the exclusion will not result in the extinction of the species.

Required Determinations—Amended

In our November 30, 2011, proposed rule (76 FR 74018), we indicated that we would defer our determination of compliance with several statutes and executive orders until the information concerning potential economic impacts of the designation and potential effects on landowners and stakeholders became available in the draft economic analysis. We have now made use of the draft economic analysis data to make these determinations. In this document, we affirm the information in our proposed rule concerning Executive Order (E.O.) 12866 (Regulatory Planning and Review), E.O. 12630 (Takings), E.O. 13132 (Federalism), E.O. 12988 (Civil Justice Reform), E.O. 13211 (Energy, Supply, Distribution, and Use), the Unfunded Mandates Reform Act (2 U.S.C. 1501 *et seq.*), the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*), the National Environmental Policy Act (42 U.S.C. 4321 *et seq.*), and the President's memorandum of April 29, 1994, ''Government-to-Government Relations with Native American Tribal Governments'' (59 FR 22951). However, based on the draft economic analysis data, we are amending our required determination concerning the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*).

Regulatory Flexibility Act (5 U.S.C. 601 et seq.)

Under the Regulatory Flexibility Act (RFA; 5 U.S.C. 601 *et seq.*), as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA; 5 U.S.C. 801 *et seq.*), whenever an agency is required to publish a notice of rulemaking for any proposed or final rule, it must prepare and make available for public comment a regulatory flexibility analysis that describes the effect of the rule on small entities (i.e., small businesses, small organizations, and small government jurisdictions). However, no regulatory flexibility analysis is required if the head of an agency certifies the rule will not have a significant economic impact on a substantial number of small entities. The SBREFA amended the RFA to require Federal agencies to provide a certification statement describing the factual basis for certifying that the rule will not have a significant economic impact on a substantial number of small entities. Based on comments we receive, we may revise this determination as part of our final rulemaking.

According to the Small Business Administration, small entities include small organizations, such as independent nonprofit organizations; small governmental jurisdictions, including school boards and city and town governments that serve fewer than 50,000 residents; and small businesses (13 CFR 121.201). For example, small businesses include manufacturing and mining concerns with fewer than 500 employees, wholesale trade entities with fewer than 100 employees, retail and service businesses with less than $5 million in annual sales, general and heavy construction businesses with less than $27.5 million in annual business, special trade contractors doing less than $11.5 million in annual business, and agricultural businesses with annual sales less than $750,000. To determine if potential economic impacts to these small entities are significant, we considered the types of activities that might trigger regulatory impacts under this designation as well as types of project modifications that may result. In general, the term ''significant economic impact'' is meant to apply to a typical small business firm's business operations.

To determine if the proposed designation of critical habitat for the southern Selkirk Mountains population of woodland caribou would affect a substantial number of small entities, we considered the number of small entities affected within particular types of economic activities, such as timber companies. In order to determine whether it is appropriate for our agency to certify that this rule would not have a significant economic impact on a substantial number of small entities, we considered each industry or category individually. We also considered whether their activities have any Federal involvement. Critical habitat designation will not affect activities that do not have any Federal involvement; designation of critical habitat only affects activities conducted, funded, permitted, or authorized by Federal agencies. In areas where the southern Selkirk Mountains population of woodland caribou is present, Federal agencies already are required to consult with us under section 7 of the Act on activities they fund, permit, or implement that may affect the species. If we finalize this proposed critical habitat designation, consultations to avoid the destruction or adverse modification of critical habitat would be incorporated into the existing consultation process.

In the draft economic analysis, we evaluated the potential economic effects on small entities resulting from implementation of conservation actions related to the proposed designation of critical habitat for the southern Selkirk Mountains population of woodland caribou. As estimated in Chapter 4 of the draft economic analysis, incremental impacts of the proposed designation are limited to additional administrative costs of considering adverse modification during section 7 consultation with the Service, as well as incremental costs associated with timber harvesting and permitting delays on private land. Approximately 17 percent of the total estimated incremental costs are projected to be borne by Federal agencies, and approximately 83 percent are projected to be incurred by private entities. Small entities may participate in section 7 consultation as a third party (the primary consulting parties being the Service and the Federal action agency); therefore, it is possible that small entities may spend additional time considering critical habitat during section 7 consultation for the southern Selkirk Mountains population of woodland caribou. Some of the forecast consultations for the southern Selkirk Mountains population of woodland caribou may involve third parties, such as timber companies and private land owners who may want to harvest timber on their land. The maximum annualized incremental impact to third parties is anticipated to total $107,000, based on a 7 percent discount rate; such costs are expected to be distributed between multiple third parties. The number of landowners is not known, therefore, we are unable to determine the incremental costs per entity. However, even if all incremental costs were borne by one small timber tract operations entity, which is unlikely, the entity would experience a 0.86 percent annual loss in revenue. This estimate is based on an average revenue for small timber tract operations companies of $3.53 million. Small entities are consequently anticipated to bear a relatively low cost impact as a result of the designation of critical habitat for the southern Selkirk Mountains population of woodland caribou. We do not believe this designation will have a significant impact on these small entities or affect a substantial number of them. Please refer to Appendix A of the draft economic analysis of the proposed critical habitat designation for a more detailed discussion of potential economic impacts.

In summary, we have considered whether the proposed designation would result in a significant economic impact on a substantial number of small entities. Information for this analysis was gathered from the Small Business Administration, stakeholders, and the Service. For the above reasons and based on currently available information, we certify that, if promulgated, the proposed designation would not have a significant economic impact on a substantial number of small business entities. Therefore, an initial regulatory flexibility analysis is not required.

A complete list of references cited in this rule is available on the internet at *http://www.regulations.gov* and upon request from the Idaho Fish and Wildlife Office (See **FOR FURTHER INFORMATION CONTACT**, above).

Authors

The primary authors of this notice are the staff members of the Idaho Fish and Wildlife Office, Pacific Region, U.S. Fish and Wildlife Service.

Authority

The authority for this action is the Endangered Species Act of 1973, as amended (16 U.S.C. 1531 *et seq.*).

Dated: May 14, 2012.

Rachel Jacobson,

Acting Assistant Secretary for Fish and Wildlife and Parks.

[FR Doc. 2012–12867 Filed 5–30–12; 8:45 am]

BILLING CODE 4310–55–P

Notices

Federal Register
Vol. 77, No. 105
Thursday, May 31, 2012

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.

COMMISSION ON CIVIL RIGHTS

Sunshine Act Meeting

AGENCY: United States Commission on Civil Rights.

ACTION: Notice of meeting.

DATE AND TIME: Friday, June 8, 2012; 9:30 a.m. EDT.

PLACE: 624 Ninth Street NW., Room 540, Washington, DC 20425.

Meeting Agenda

This meeting is open to the public.

I. Approval of Agenda

II. Program Planning Update and Discussion of Projects:

- Discussion on Strategic Plan
- Discussion on 2012 Statutory Report
- Vote on 2013 Statutory Report Topic

III. Management and Operations

- Discussion on 2012 Budget and 2013 Budget Request
- Discussion on Agency Staffing

IV. Adjourn Meeting

CONTACT PERSON FOR FURTHER INFORMATION: Lenore Ostrowsky, Acting Chief, Public Affairs Unit (202) 376–8591.

Hearing-impaired persons who will attend the meeting and require the services of a sign language interpreter should contact Pamela Dunston at (202) 376–8105 or at *signlanguage@usccr.gov* at least seven business days before the scheduled date of the meeting.

Dated: May 29, 2012.

Kimberly Tolhurst,

Senior Attorney-Advisor.

[FR Doc. 2012–13284 Filed 5–29–12; 11:15 am]

BILLING CODE 6335–01–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

RIN 0648–XC050

Marine Mammals; File No. 17236

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

ACTION: Notice; receipt of application.

SUMMARY: Notice is hereby given that Robert A. Garrott, Ecology Department, Montana State University, 310 Lewis Hall, Bozeman, MT, 59717, has applied in due form for a permit to conduct research on Weddell seals (*Leptonychotes weddellii*).

DATES: Written, telefaxed, or email comments must be received on or before July 2, 2012.

ADDRESSES: The application and related documents are available for review by selecting ''Records Open for Public Comment'' from the *Features* box on the Applications and Permits for Protected Species (APPS) home page, *https://apps.nmfs.noaa.gov,* and then selecting File No. 17236 from the list of available applications.

These documents are also available upon written request or by appointment in the following offices:

Permits and Conservation Division, Office of Protected Resources, NMFS, 1315 East-West Highway, Room 13705, Silver Spring, MD 20910; phone (301) 427–8401; fax (301) 713–0376; and

Southwest Region, NMFS, 501 West Ocean Blvd., Suite 4200, Long Beach, CA 90802–4213; phone (562) 980–4001; fax (562) 980–4018.

Written comments on this application should be submitted to the Chief, Permits and Conservation Division, at the address listed above. Comments may also be submitted by facsimile to (301) 713–0376, or by email to *NMFS.Pr1Comments@noaa.gov.* Please include the File No. in the subject line of the email comment.

Those individuals requesting a public hearing should submit a written request to the Chief, Permits and Conservation Division at the address listed above. The request should set forth the specific reasons why a hearing on this application would be appropriate.

FOR FURTHER INFORMATION CONTACT: Colette Cairns or Tammy Adams, (301) 427–8401.

SUPPLEMENTARY INFORMATION: The subject permit is requested under the authority of the Marine Mammal Protection Act of 1972, as amended (MMPA; 16 U.S.C. 1361 *et seq.*), and the regulations governing the taking and importing of marine mammals (50 CFR part 216).

The purpose of the research is to evaluate how environmental variability and individual heterogeneity affects the population dynamics of Weddell seals in the Antarctic. The applicant proposes to continue long-term studies of the Weddell seal population in the Erebus Bay, McMurdo Sound, Ross Sea and White Island areas of Antarctica. Up to 425 adults and 700 pups would be captured annually. Animals would be weighed, tissued sampled, flipper tagged, and released. A subset of 200 pups annually would have a small temperature logging tag attached. The applicant requests authorization to opportunistically collect, import, and export Weddell seal parts and carcasses. Annually up to 2,000 Weddell, 50 crabeater (*Lobodon carcinophagus*), and 50 leopard (*Hydrurga leptonyx*) seals may be incidentally disturbed as a result of the research activities. The applicant requests authorization for up to 4 (2 adults and 2 pups) Weddell seal research-related mortalities annually. The permit would be valid for five years from the date of issuance.

In compliance with the National Environmental Policy Act of 1969 (42 U.S.C. 4321 *et seq.*), an initial determination has been made that the activity proposed is categorically excluded from the requirement to prepare an environmental assessment or environmental impact statement.

Concurrent with the publication of this notice in the **Federal Register**, NMFS is forwarding copies of the application to the Marine Mammal Commission and its Committee of Scientific Advisors.

Dated: May 23, 2012.

Tammy C. Adams,

Acting Chief, Permits and Conservation Division, Office of Protected Resources, National Marine Fisheries Service.

[FR Doc. 2012–13113 Filed 5–30–12; 8:45 am]

BILLING CODE 3510–22–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

New England Fishery Management Council (NEFMC); Public Meeting

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

ACTION: Notice of a public meeting.

SUMMARY: The New England Fishery Management Council (Council) will hold a three-day meeting on June 19–21, 2012 to consider actions affecting New England fisheries in the exclusive economic zone (EEZ).

DATES: The meeting will be held on Tuesday, Wednesday and Thursday, June 19–21, starting at 9 a.m. on Tuesday, and at 8:30 a.m. on Wednesday and Thursday.

ADDRESSES: The meeting will be held at the Holiday Inn by the Bay, 88 Spring Street, Portland, ME 04101; telephone: (207) 775–2311; fax: (207) 761–8224.

Council address: New England Fishery Management Council, 50 Water Street, Mill 2, Newburyport, MA 01950; telephone (978) 465–0492.

FOR FURTHER INFORMATION CONTACT: Paul J. Howard, Executive Director, New England Fishery Management Council; telephone: (978) 465–0492.

SUPPLEMENTARY INFORMATION:

Tuesday, June 19, 2012

Following introductions and any announcements, brief reports will be provided by the NEFMC Chairman and Executive Director, the Acting NOAA Fisheries Regional Administrator (Northeast Region), the Northeast Fisheries Science Center and Mid-Atlantic Fishery Management Council liaisons, NOAA General Counsel, representatives of the U.S. Coast Guard and the Atlantic States Marine Fisheries Commission, and staff from the regional Vessel Monitoring Systems Operations and Law Enforcement offices. The Council will then receive an update from NOAA Fisheries Northeast Regional Office staff about the development of a new amendment to address Standard Bycatch Reporting Methodology in all NEFMC fishery management plans (FMPs).

Following a lunch break, the Northeast Fisheries Science Center (NEFSC) will present a briefing on their new social science data collection efforts. Following this report, the Council's Habitat Committee will provide an overview of the discretionary provisions of the Magnuson-Stevens Fishery Conservation and Management Act that relate to deep sea corals. Its members may ask the Council to consider removing the coral alternatives from the Omnibus Essential Fish Habitat Amendment currently under development and address them in a separate action. There also will be an NEFSC presentation summarizing the most recent scientific information about climate change and its impact on fisheries in the Northeast. NOAA Fisheries staff will then address scoping for Amendment 7 to the Consolidated Highly Migratory Species Fishery Management Plan. This will include the scope and significance of issues to be analyzed in a draft environmental impact statement on management measures that address Atlantic bluefin tuna (BFT) management. Through the scoping process, NMFS will determine if existing measures are the best means of achieving certain management objectives for BFT and provide flexibility for future management. NMFS also will hold a scoping hearing on Monday evening, June 18 at the same location as the Council meeting for interested stakeholders and the public. Attendees are encouraged to check *www.nero.noaa.gov* or *www.nefmc.org* for the time. The day will conclude with a public listening session during which the Council will hold an informal question and answer session for stakeholders and the public. There also will be an opportunity for anyone to briefly comment on items relevant to Council business that is not otherwise listed on the agenda.

Wednesday, June 20, 2012

The Council will use the entire day on Wednesday to review and approve final measures to be included in Amendment 5 to the Atlantic Herring FMP. Amendment 5 proposes to establish a catch monitoring program for the herring fishery and address bycatch. It may include: adjustments to the fishery management program; measures to address carrier vessels and transfers at-sea; trip notification and permitting, and reporting requirements. If approved, other measures may address interactions with the Atlantic mackerel fishery, allocate observer coverage on limited access herring vessels, maximize sampling and address net slippage, address river herring bycatch and establish criteria for midwater trawl vessel access to groundfish closed areas.

Thursday, June 21, 2012

The third and final day of the NEFMC meeting will begin with reports from the Monkfish and Whiting Committees. The Monkfish Committee will ask the Council to consider a motion deferred from the April Council meeting that would remove Individually Transferrable Quotas from the range of alternatives under development in Amendment 6 to the Monkfish FMP. The Whiting Committee will ask for final approval of Amendment 19 draft management measures including alternatives to increase the whiting possession limit from 30,000 up to 40,000 pounds for vessels using trawls with 3-inch or larger mesh, in all or part of the Southern New England and Mid-Atlantic Exemption Areas. The rest of the day will be spent on issues that relate to the Northeast multispecies stock complex. The Council will discuss and possibly propose action to mitigate the impact of the low catch limits recently set for Georges Bank yellowtail flounder. It also will: receive a summary of the scoping comments submitted for proposed Amendment 18 to the Northeast Multispecies FMP; approve initial action on a framework adjustment to modify sector measures (including monitoring requirements), as well as set acceptable biological catches for fishing year 2013–15; and adjust annual catch limits and accountability measures.

Although other non-emergency issues not contained in this agenda may come before this Council for discussion, those issues may not be the subjects of formal action during this meeting. Council 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 305(c) of the Magnuson-Stevens Act, provided that the public has been notified of the Council's 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 Paul J. Howard (see **ADDRESSES**) at least 5 days prior to the meeting date.

Dated: May 25, 2012.

Tracey L. Thompson,

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

[FR Doc. 2012–13178 Filed 5–30–12; 8:45 am]

BILLING CODE 3510–22–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

Gulf of Mexico Fishery Management Council; Public Meetings

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

ACTION: Notice of public meetings.

SUMMARY: The Gulf of Mexico Fishery Management Council (Council) will convene public meetings.

DATES: The meetings will be held June 18–21, 2012.

ADDRESSES: The meetings will be held at the Hilton Westshore Airport Hotel, 2225 N. Lois Avenue; Tampa, FL; telephone: (813) 877–6688.

Council address: Gulf of Mexico Fishery Management Council, 2203 North Lois Avenue, Suite 1100, Tampa, FL 33607.

FOR FURTHER INFORMATION CONTACT: Dr. Stephen Bortone, Executive Director, Gulf of Mexico Fishery Management Council; telephone: (813) 348–1630.

SUPPLEMENTARY INFORMATION:

Committees

Monday, June 18, 2012

1 p.m.–1:30 p.m.—Administrative Policy Committee will receive a staff presentation of the visit from the Inspector General's office.

1:30 p.m.–3 p.m.—Ad Hoc Restoration Committee will review State summaries and receive presentations.

3 p.m.–4:30 p.m.—Data Collection Committee will review the Ad Hoc Private Recreational Data Collection Advisory Panel Report and discuss the Public Hearing draft for a Generic Amendment for Dealer Permits/Electronic Logbook Reporting Requirements.

4:30 p.m.–5:30 p.m.—Sustainable Fisheries/Ecosystem Committee will discuss the Council's Risk Policy.

5:30 p.m.–6:30 p.m.—Shrimp Management Committee will review a report from the Shrimp Workshop and the Shrimp Scientific & Statistical Committee meetings; discuss the funding for the Electronic Logbooks Program (ELB); receive a report on the Kemps Ridley Assessment Workshop; review the Status of the National Marine Fisheries Service's Biological Opinion and Proposed Turtle Excluder Device (TEDs) Requirement; and discuss Exempted Fishing Permits related to Shrimp (if any).

—Recess—

Tuesday, June 19, 2012

8:30 a.m.–12:15 p.m. and 1:30 p.m.–5:45 p.m.—Reef Fish Management Committee will receive a presentation by Louisiana DWF on Regional Management; review Options Papers for Amendment 28—Grouper Allocation, Amendment 37—Gray Triggerfish Rebuilding Plan; and review a Framework Action for the 2013 Gag Season, a potential Split Season and possibly eliminating the February—March Shallow-Water Grouper Closure. The Committee will also review a Public Hearing draft of Amendment 38—Revise Post-Season Recreational Accountability Measures for Shallow-Water Grouper; a Revision to the Generic Framework Procedure; and a Scoping Document for Amendment 39—Sector Separation. Finally, the Committee will review possible abbreviated Framework Actions regarding Venting Tool Requirements and Definition and Intent of For-hire Fishing in the EEZ; have a discussion on the National Standard 1; and discuss Exempted Fishing Permits related to Reef Fish (if any).

—Recess—

Immediately following the Committee Recess will be the Informal Question & Answer Session on Gulf of Mexico Fishery Management Issues.

Wednesday, June 20, 2012

8:30 a.m.–9:30 a.m.—The Joint Artificial Reef/Habitat Committees will discuss Artificial Reefs and Petroleum Platforms being designated as Essential Fish Habitat.

9:30 a.m.–12 noon—The Mackerel Management Committee will review drafts for the Coastal Migratory Pelagics Amendment 19—Bag Limit Sales, Trip Limits and Latent Gill Net Permits and for Amendment 20—Boundaries and Transit Provisions and discuss Exempted Fishing Permits to Coastal Migratory Pelagics (if any).

—Recess—

Council

Wednesday, June 20, 2012

1:30 p.m.—The Council meeting will begin with a Call to Order and Introductions.

1:45 p.m.–1:55 p.m.—The Council will review the agenda and approve the minutes.

1:55 p.m.–2 p.m.—The Council will review the Action Schedule.

2 p.m.–2:15 p.m.—The Council will review Exempted Fishing Permits (EFP), if any.

2:15 p.m.–5:30 p.m.—The Council will receive public testimony on Exempted Fishing Permits (EFPs), if any; and will also hold an open public comment period regarding any other fishery issues or concern. People wishing to speak before the Council should complete a public comment card prior to the comment period.

Thursday, June 21, 2012

8:30 a.m.–8:45 a.m.—The Council will have a discussion on Exempted Fishing Permits (if any).

8:45 a.m.–3:15 p.m.—The Council will review and discuss reports from the committee meetings as follows: Administrative Policy, Reef Fish, Ad Hoc Restoration, Data Collection, Shrimp, Joint Artificial Reef/Habitat, Mackerel, and Sustainable Fisheries/Ecosystem.

3:15 p.m.–3:45 p.m.—Other Business items will follow.

The Council will conclude its meeting at approximately 3:45 p.m.

Although other non-emergency issues not on the agendas may come before the Council and Committees for discussion, in accordance with the Magnuson Stevens Fishery Conservation and Management Act (Magnuson-Stevens Act), those issues may not be the subject of formal action during these meetings. Actions of the Council and Committees will be restricted to those issues specifically identified in the agendas and any issues arising after publication of this notice that require emergency action under Section 305(c) of the Magnuson-Stevens Act, provided the public has been notified of the Council's intent to take action to address the emergency. The established times for addressing items on the agenda may be adjusted as necessary to accommodate the timely completion of discussion relevant to the agenda items. In order to further allow for such adjustments and completion of all items on the agenda, the meeting may be extended from, or completed prior to the date/time established in this notice.

Special Accommodations

These meetings are physically accessible to people with disabilities. Requests for sign language interpretation or other auxiliary aids should be directed to Kathy Pereira at the Council (see **ADDRESSES**) at least 5 working days prior to the meeting.

Dated: May 25, 2012.

Tracey L. Thompson,

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

[FR Doc. 2012–13211 Filed 5–30–12; 8:45 am]

BILLING CODE 3510–22–P

CORPORATION FOR NATIONAL AND COMMUNITY SERVICE

Information Collection; Submission for OMB Review, Comment Request

AGENCY: Corporation for National and Community Service.

ACTION: Notice.

SUMMARY: The Corporation for National and Community Service (the Corporation), has submitted a public information collection request (ICR) entitled Segal AmeriCorps Education Award Matching Program Commitment Form for review and approval in accordance with the Paperwork Reduction Act of 1995, Public Law 104–13, (44 U.S.C. chapter 35). Copies of this ICR, with applicable supporting documentation, may be obtained by calling the Corporation for National and Community Service, Calvin Dawson, at (202) 606–6897 or email to *cdawson@cns.gov.* Individuals who use a telecommunications device for the deaf (TTY–TDD) may call 1–800–833–3722 between 8 a.m. and 8 p.m. Eastern Time, Monday through Friday.

ADDRESSES: Comments may be submitted, identified by the title of the information collection activity, to the Office of Information and Regulatory Affairs, Attn: Ms. Sharon Mar, OMB Desk Officer for the Corporation for National and Community Service, by any of the following two methods within 30 days from the date of publication in the **Federal Register**:

(1) *By fax to:* (202) 395–6974, Attention: Ms. Sharon Mar, OMB Desk Officer for the Corporation for National and Community Service; and

(2) *Electronically by email to: smar@omb.eop.gov.*

SUPPLEMENTARY INFORMATION: 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 Corporation, 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;
- Propose ways to enhance the quality, utility, and clarity of the information to be collected; and
- Propose ways to 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 submissions of responses.

Comments

A 60-day public comment Notice was published in the **Federal Register** on February 28, 2012. This comment period ended April 30, 2012. One individual submitted public comments. One comment was that the form should include specific explanation of how the matching program works. In response, a program purpose section has been added to the form. Another comment was to show some links to the Corporation for National and Community Service Web site. In response, in addition to the link that already appears on the Form for FAQs, an additional link to the Corporation's Web site has been added. Additional comments related to ideas for organizing the Corporation's Web site. In response, since these ideas relate to the Web site and not to the Form itself then no changes to the Form was needed.

Description: The Corporation is seeking approval of Segal AmeriCorps Education Award Matching Program Commitment Form to be used by colleges and universities to submit to the Corporation for National and Community Service to obtain approval for information on them to appear on the Segal AmeriCorps Education Awards section of the Corporation for National and Community Service Web site.

Type of Review: New.

Agency: Corporation for National and Community Service.

Title: Segal AmeriCorps Education Award Matching Program Commitment Form.

OMB Number: TBD.

Agency Number: None.

Affected Public: Colleges and Universities.

Total Respondents: Estimated 200 Colleges and Universities.

Frequency: Once every five years.

Average Time per Response: 30 minutes.

Estimated Total Burden Hours: 100 hours.

Total Burden Cost (Capital/Startup): None.

Total Burden Cost (Operating/ Maintenance): None.

Dated: May 23, 2012.

Idara Nickelson,

Chief of Program Operations.

[FR Doc. 2012–13209 Filed 5–30–12; 8:45 am]

BILLING CODE 6050–$$–P

DEPARTMENT OF EDUCATION

Notice of Proposed Information Collection Requests; Office of Planning, Evaluation and Policy Development; EDFacts Collection of Elementary and Secondary Education Act of 1965 (ESEA) Flexibility Data

SUMMARY: On September 23, 2011, the U.S. Department of Education (ED) invited State educational agencies (SEAs) to request flexibility pursuant to the authority in section 9401 of ESEA, which allows the Secretary of Education to waive, with certain exceptions, any statutory or regulatory requirement of the ESEA for an SEA that receives funds under a program authorized by the ESEA and requests a waiver. In order to ensure that SEAs receiving ESEA flexibility are continuing to meet the intent and purpose of Title I of ESEA, including meeting the educational needs of low-achieving students, closing achievement gaps, and holding schools, local educational agencies, and SEAs accountable for improving the academic achievement of all students, ED will continue to collect all data related to student proficiency rates as well as performance against the annual measurable objectives. This collection will be applicable to SEAs with approved flexibility requests.

DATES: Interested persons are invited to submit comments on or before July 30, 2012.

ADDRESSES: Written comments regarding burden and/or the collection activity requirements should be electronically mailed to *ICDocketMgr@ed.gov* or mailed to U.S. Department of Education, 400 Maryland Avenue SW., LBJ, Washington, DC 20202–4537. 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 04860. 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., LBJ, Washington, DC 20202–4537. Requests may also be electronically mailed to *ICDocketMgr@ed.gov* or faxed to 202–401–0920. Please specify the complete title of the information collection and OMB Control Number when making your request.

Individuals who use a telecommunications device for the deaf (TDD) may call the Federal Information Relay Service (FIRS) at 1–800–877–8339.

SUPPLEMENTARY INFORMATION: Section 3506 of the Paperwork Reduction Act of 1995 (44 U.S.C. Chapter 35) requires that Federal agencies provide interested parties an early opportunity to comment on information collection requests. The Director, Information Collection Clearance Division, Privacy, Information and Records Management Services, Office of Management, publishes this notice containing proposed information collection requests at the beginning of the Departmental review of the information collection. 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. Please note that written comments received in response to this notice will be considered public records.

Title of Collection: EDFacts Collection of ESEA Flexibility Data.

OMB Control Number: Pending.

Type of Review: New.

Total Estimated Number of Annual Responses: 52.

Total Estimated Number of Annual Burden Hours: 1,248.

Abstract: On September 23, 2011, the U.S. Department of Education (ED) invited each State educational agency (SEA) to voluntarily request flexibility on behalf of itself, its local educational agencies, and schools, in order to better focus on improving student learning and increasing the quality of instruction. Since then, ED has approved 11 SEA requests for flexibility, and is currently reviewing an additional 27 requests. ED expects to receive requests from additional SEAs by September 6, 2012. SEAs are invited to request flexibility pursuant to the authority in section 9401 of the Elementary and Secondary Education Act of 1965 (ESEA), which allows the Secretary of Education to waive, with certain exceptions, any statutory or regulatory requirement of the ESEA for an SEA that receives funds under a program authorized by the ESEA and requests a waiver. This clearance request is for the collection of data that may be needed to ensure that SEAs receiving ESEA flexibility are continuing to meet the intent and purpose of Title I of ESEA, including meeting the educational needs of low-achieving students, closing achievement gaps, and holding schools, local educational agencies, and SEAs accountable for improving the academic achievement of all students. This collection will be applicable to SEAs with approved flexibility plans. In order to reduce burden on SEAs and maximize the availability and utility of the data within ED, ED plans to require states to submit these data electronically through EDFacts, as allowable under 34 CF. Part 76. ''Flexibility Clearance Attachment B'' outlines the 22 new data groups proposed for collection. ED is requesting SEAs to review the last page of Attachment B which provides two directed questions (see the link to EDICSweb to link number 04860 in the Addresses section above.) ED is requesting the data providers of each SEA respond to two specific questions about the proposed data groups. Responses to these questions will help ED determine whether or not to adjust the proposed data groups, as well as to determine which of the data can currently be provided by SEAs.

Dated: May 24, 2012.

Darrin A. King,

Director, Information Collection Clearance Division, Privacy, Information and Records Management Services, Office of Management.

[FR Doc. 2012–13182 Filed 5–30–12; 8:45 am]

BILLING CODE 4000–01–P

DEPARTMENT OF EDUCATION

Privacy Act of 1974, as Amended; Renewal of Computer Matching Program Between the U.S. Department of Education and the Internal Revenue Service

AGENCY: Department of Education.

ACTION: Notice.

SUMMARY: This document provides notice of the renewal of the computer matching program between the U.S. Department of Education (ED) and the Internal Revenue Service (IRS). The computer matching program will begin on the effective date specified in paragraph 5.

SUPPLEMENTARY INFORMATION: ED originally published the notice of the matching program between ED and IRS in the **Federal Register** on July 28, 2006 (71 FR 42839). The computer matching program became effective for a period of 18 months on January 28, 2007. On July 10, 2009, IRS and ED extended the computer matching program for an additional 12 months from July 28, 2009, through July 27, 2010. The computer matching program expired on July 27, 2010.

This notice is provided under the Privacy Act of 1974 (5 U.S.C. 552a), as amended by the Computer Matching and Privacy Protection Act of 1988 (Pub. L. 100–503) and the Computer Matching and Privacy Protection Amendments of 1990 (Pub. L. 101–508) (Privacy Act); the Office of Management and Budget (OMB) Final Guidance Interpreting the Provisions of Public Law 100–503, the Computer Matching and Privacy Protection Act of 1988, 54 FR 25818 (June 19, 1989); and OMB Circular A–130, Appendix 1.

1. Name of Participating Agencies

The U.S. Department of Education and the Internal Revenue Service.

2. Purpose of the Match

The purpose of this matching program, entitled Taxpayer Address Request (TAR), is to permit ED to have access to the mailing address of any taxpayer who owes an overpayment of a grant awarded under subpart 1 of part A of title IV of the Higher Education Act of 1965, as amended (HEA) or who has defaulted on a loan made under parts B, D, or E of title IV of the HEA. ED will use taxpayer addresses to collect grant overpayments and loan debts.

In accordance with section 6103(m)(4)(B) of the Internal Revenue Code (IRC) (26 U.S.C. 6103(m)(4)(B)), the computer matching agreement between ED and IRS provides for redisclosure by the Secretary of Education of a taxpayer's mailing address to any lender, or State or nonprofit guarantee agency that is participating under part B or D of title IV of the HEA, or any educational institution with which the Secretary of Education has an agreement under subpart 1 of part A or part D or E of title IV of the HEA. In addition, this matching program permits ED to have access to the mailing address of a taxpayer for use by ED and its agents for purposes of locating such taxpayer to collect or compromise a Federal claim against the taxpayer in accordance with 31 U.S.C. 3711, 3717, and 3718.

3. Authority for Conducting the Matching Program

The information contained in the IRS database is referred to as the TAR, and the matching program between ED and IRS is authorized under section 6103(m)(2) and (m)(4) of the IRC (26 U.S.C. 6103(m)(2) and (m)(4)).

4. Categories of Records and Individuals Covered by the Match

The records to be used in the match are described as follows:

ED will provide to the IRS the Social Security number (SSN) and first four letters of the last name of each student who has defaulted under a loan program authorized under part B, D, or E of title IV of the HEA or who owes a grant overpayment for a grant authorized under subpart 1 of part A of title IV of the HEA. This information will be extracted from ED's system of records entitled ''Common Services for Borrowers (CSB)'' (18–11–16) (71 FR 3503 (January 23, 2006)).

The ED data described in the preceding paragraph will be matched against the IRS' system of records, CADE Individual Master File (IMF), Treasury/IRS 24.030 (last published at 73 FR 13304 (March 12, 2008)) in order to collect the most recent mailing address of each taxpayer who matches the SSN and first four letters of the last name as provided by ED.

5. Effective Dates of the Matching Program

The matching program will become effective at the latest of the following dates: (1) 40 Days after the signing of the transmittal letter sending the computer matching program report to Congress and OMB, unless OMB disapproves the matching program within the 40-day review period; (2) if OMB waives 10 days of the 40-day review period, then 30 days after the signing of the transmittal letter sending the computer matching program report to Congress and OMB; or (3) 30 days after publication of this notice in the **Federal Register**. The matching program will continue for 18 months after the effective date and may be extended for an additional 12 months if the conditions specified in 5 U.S.C. 552a(o)(2)(D) have been met.

6. Address for Receipt of Public Comments or Inquiries

Individuals wishing to comment on this matching program or obtain additional information about the program, including requesting a copy of the computer matching agreement between ED and IRS, may contact Marian Currie, Management and Program Analyst, Federal Student Aid, U.S. Department of Education, 830 First Street NE., Union Center Plaza, room #43B2, Washington, DC 20202–5320. Telephone: 202–377–3212; and as a secondary contact, Dwight Vigna, Director, Default Division, Federal Student Aid, U.S. Department of Education, 830 First Street NE., Union Center Plaza, room #41F2, Washington, DC 20202–5320. Telephone: (202) 377–3436. If you use a telecommunications device for the deaf (TTD) or a text telephone (TTY), you may call the Federal Relay Service (FRS) at 1–800–877–8339.

Individuals with disabilities can obtain this document in an alternative format (e.g., braille, large print, audiotape, or computer diskette) on request to either contact person listed in the previous paragraph.

Electronic Access to the Document: 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 via the Federal Digital System at: *www.gpo.gov/fdsys.* At this site you can 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). To use PDF you must have Adobe Acrobat Reader, which is available free at the site.

You may also access documents of the Department published in the **Federal Register** by using the article search feature at: *www.federalregister.gov.* Specifically, through the advanced search feature at this site, you can limit your search to documents published by the Department.

Authority: The Privacy Act of 1974, as amended (5 U.S.C. 552a) and Sections 6103(m)(2) and (m)(4) of the Internal Revenue Code (26 U.S.C. 6103(m)(2) and (m)(4)).

Dated: May 24, 2012.

James W. Runcie,

Chief Operating Officer Federal Student Aid.

[FR Doc. 2012–13105 Filed 5–30–12; 8:45 am]

BILLING CODE 4000–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Combined Notice of Filings

Take notice that the Commission has received the following Natural Gas Pipeline Rate and Refund Report filings:

Filings Instituting Proceedings

Docket Numbers: RP12–745–000.
Applicants: Natural Gas Pipeline Company of America.
Description: Macquarie Energy Negotiated Rate to be effective 6/1/2012.
Filed Date: 5/22/12.
Accession Number: 20120522–5135.
Comments Due: 5 p.m. ET 6/4/12.

Docket Numbers: RP12–746–000.
Applicants: Northern Border Pipeline Company.
Description: Housekeeping to be effective 6/25/2012.
Filed Date: 5/23/12.
Accession Number: 20120523–5124.
Comments Due: 5 p.m. ET 6/4/12.

Docket Numbers: RP12–747–000.
Applicants: Kern River Gas Transmission Company.
Description: 2012 High Desert to be effective 8/19/2010.
Filed Date: 5/23/12.
Accession Number: 20120523–5158.
Comments Due: 5 p.m. ET 6/4/12.

Any person desiring to intervene or protest in any of the above proceedings must file in accordance with Rules 211 and 214 of the Commission's Regulations (18 CFR 385.211 and 385.214) on or before 5 p.m. Eastern time on the specified comment date. Protests may be considered, but intervention is necessary to become a party to the proceeding.

Filings in Existing Proceedings

Docket Numbers: RP12–573–001.
Applicants: Millennium Pipeline Company, LLC.
Description: Negotiated Rate SVC Agmt—130060, etc. to be effective 5/1/2012.
Filed Date: 5/9/12.
Accession Number: 20120509–5076.
Comments Due: 5 p.m. ET 5/21/12.

Any person desiring to protest in any the above proceedings must file in accordance with Rule 211 of the Commission's Regulations (18 CFR 385.211) on or before 5 p.m. Eastern time on the specified comment date.

The filings are accessible in the Commission's eLibrary system by clicking on the links or querying the docket number.

eFiling is encouraged. More detailed information relating to filing requirements, interventions, protests, and service can be found at: *http://www.ferc.gov/docs-filing/efiling/filing-req.pdf.* For other information, call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Dated: May 25, 2012.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2012–13202 Filed 5–30–12; 8:45 am]

BILLING CODE 6717–01–P

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–OA–2006–0278; FRL–9669–9]

Agency Information Collection Activities; Proposed Collection; Comment Request; Participation by Disadvantaged Business Enterprises in Procurement Under Environmental Protection Agency (EPA) Financial Assistance Agreements (Renewal); EPA ICR No. 2047.04

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: In compliance with the Paperwork Reduction Act (PRA)(44 U.S.C. 3501 *et seq.*), this document announces that EPA is planning to submit a request to reinstate an Information Collection Request (ICR) to the Office of Management and Budget (OMB). This ICR expired on January 31, 2011. Before submitting the ICR to OMB for review and approval, EPA is soliciting comments on specific aspects of the proposed information collection as described below.

DATES: Comments must be submitted on or before July 30, 2012.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–HQ–OA–2006–0278, by one of the following methods:

- *www.regulations.gov:* Follow the on-line instructions for submitting comments.
- *Email: oei.docket@epa.gov.*
- *Fax:* 202–566–9744.
- *Mail:* OEI Docket, Environmental Protection Agency, Mailcode: 28221T, 1200 Pennsylvania Ave. NW., Washington, DC 20460.
- *Hand Delivery:* EPA Docket Center, Environmental Protection Agency, Room 3334, 1301 Constitution Ave. NW., Washington, DC. 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–OA–2006–0278. 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 CBI or otherwise protected through *www.regulations.gov* or email. 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 email comment directly to EPA without going through *www.regulations.gov* your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. 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 *www.epa.gov/epahome/dockets.htm.*

FOR FURTHER INFORMATION CONTACT: Teree Henderson, Office of Small Business Programs, Mailcode: 1230T, Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20460; telephone number: 202–566–2222; fax number: 202–566–0548; email address: *Henderson.Teree@epa.gov.*

SUPPLEMENTARY INFORMATION:

How can I access the docket and/or submit comments?

EPA has established a public docket for this ICR under Docket ID No. EPA–HQ–OA–2006–0278, which is available for online viewing at *www.regulations.gov,* or in person viewing at the Office of Environmental Information Docket in the EPA Docket Center (EPA/DC), EPA West, Room 3334, 1301 Constitution Ave. NW., Washington, DC. The EPA/DC 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 Reading Room is 202–566–1744, and the telephone number for the Office of Environmental Information Docket is 202–566–1752. Use *www.regulations.gov* to obtain a copy of the draft collection of information, submit or view public comments, access the index listing of the contents of the docket, and to access those documents in the public docket that are available electronically. Once in the system, select ''search,'' then key in the docket ID number identified in this document.

What information is EPA particularly interested in?

Pursuant to section 3506(c)(2)(A) of the PRA, EPA specifically solicits comments and information to enable it to:

i. 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;

ii. 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;

iii. Enhance the quality, utility, and clarity of the information to be collected; and

iv. 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. In particular, EPA is requesting comments from very small businesses (those that employ less than 25) on examples of specific additional efforts that EPA could make to reduce the paperwork burden for very small businesses affected by this collection.

What should I consider when I prepare my comments for EPA?

You may find the following suggestions helpful for preparing your comments:

1. Explain your views as clearly as possible and provide specific examples.
2. Describe any assumptions that you used.
3. Provide copies of any technical information and/or data you used that support your views.
4. If you estimate potential burden or costs, explain how you arrived at the estimate that you provide.
5. Offer alternative ways to improve the collection activity.
6. Make sure to submit your comments by the deadline identified under **DATES**.
7. To ensure proper receipt by EPA, be sure to identify the docket ID number assigned to this action in the subject line on the first page of your response. You may also provide the name, date, and **Federal Register** citation.

What information collection activity or ICR does this apply to?

Affected entities: Entities potentially affected by this action are all recipients of EPA financial assistance agreements, and any entities receiving identified loans under a financial assistance agreement capitalizing a revolving loan fund.

Title: Participation by Disadvantaged Business Enterprises in Procurement under EPA Financial Assistance Agreements (Reinstatement).

ICR numbers: EPA ICR No. 2047.04, OMB Control No. 2090–0030.

ICR status: This ICR expired on January 31, 2011. 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 title 40 of the CFR, after appearing in the **Federal Register** when approved, are listed in 40 CFR part 9, are displayed either by publication in the **Federal Register** or by other appropriate means, such as on the related collection instrument or form, if applicable. The display of OMB control numbers in certain EPA regulations is consolidated in 40 CFR part 9.

Abstract: EPA currently requires an entity to be certified in order to be considered a Minority Business Enterprise (MBE) or Women's Business Enterprise (WBE) under EPA's Disadvantaged Business Enterprise (DBE) Program. EPA currently requires an entity to first attempt to become certified by a federal agency (*e.g.,* the Small Business Administration (SBA), or the Department of Transportation (DOT)), or by a State, locality, Indian Tribe or independent private organization so long as their applicable criteria match those under Section 8(a)(5) and (6) of the Small Business Act and applicable implementing regulations. EPA only certifies firms that are denied certification by one of these entities. To qualify as an MBE or WBE under EPA's programs an entity must establish that it is owned and/or controlled by socially and economically disadvantaged individuals who are of good character and are citizens of the United States. Entities that meet the aforementioned requirements and wish to obtain an EPA DBE certification must submit a DBE Certification Application to the Office of Small Business Programs based on business type: Sole Proprietorship (6100–1a); Limited Liability Company (6100–1b); Partnership (6100–1c); Corporation (6100–1d); Alaska Native Corporation (6100–1e); Tribally Owned Business (6100–1f); Private and Voluntary Organization (6100–1g); Native Hawaiian Organization (6100–1h); or Community Development Corporation (6100–1i).

The EPA DBE Program also includes contract administration requirements designed to prevent unfair practices that adversely affect DBEs. There are three forms associated with these requirements: EPA Form 6100–2 (DBE Subcontractor Participation Form), EPA Form 6100–3 (DBE Subcontractor Performance Form), and EPA Form 6100–4 (DBE Subcontractor Utilization Form). The requirements to complete these forms are intended to prevent any ''bait and switch'' tactics at the subcontract level by prime contractors which may circumvent the spirit of the DBE Program.

Burden Statement: The combined total annual public reporting and recordkeeping burden for all forms associated with this collection of information is estimated to average three (3) hours and fifteen (15) minutes per response. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This burden estimate 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 which have subsequently changed; 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. The ICR provides a detailed explanation of the Agency's estimate, which is only briefly summarized here:

• *Estimated total number of potential respondents:* 3600.

• *Frequency of response:* Certification: Every three years or more often as required. Form 6100–2: As needed, Form 6100–3 and Form 6100–4: At the time of bid or proposal.

• *Estimated total average number of responses for each respondent:* 3600.

• *Estimated total annual burden hours:* 11,700 (three hours and fifteen minutes per respondent).

• *Estimated total annual costs:* $146,916. This includes an estimated burden cost of $146,916, and an estimated cost of $0 for capital investment or maintenance and operational costs.

Are there changes in the estimates from the last approval?

There will be a change in the total estimated respondent burden compared with that identified in the ICR currently approved by OMB. The 6100–2, –3, and –4 forms have been revised to include more detailed instructions, which should decrease the amount of time it takes to complete each form.

What is the next step in the process for this ICR?

EPA will consider the comments received and amend the ICR as appropriate. The final ICR package will then be submitted to OMB for review and approval pursuant to 5 CFR 1320.12. At that time, EPA will issue another **Federal Register** notice pursuant to 5 CFR 1320.5(a)(1)(iv) to announce the submission of the ICR to OMB and the opportunity to submit additional comments to OMB. If you have any questions about this ICR or the approval process, please contact the technical person listed under **FOR FURTHER INFORMATION CONTACT**.

Dated: May 13, 2012.

John Reeder,

Deputy Chief of Staff.

[FR Doc. 2012–13188 Filed 5–30–12; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

EPA Board of Scientific Counselors Advisory Board; Notice of Charter Renewal

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of Charter Renewal.

Notice is hereby given that the Environmental Protection Agency (EPA) has determined that, in accordance with the provisions of the Federal Advisory Committee Act (FACA), 5 U.S.C. App.2, the EPA Board of Scientific Counselors Advisory Board (BOSC) is a necessary committee which is in the public interest. Accordingly, BOSC will be renewed for an additional two-year period. The purpose of BOSC is to provide advice and recommendations to the Administrator regarding science and engineering research, programs and plans, laboratories, and research-management practices. Inquiries may be directed to Greg Susanke, U.S. EPA, (Mail Code 8104R), 1200 Pennsylvania Avenue NW., Washington, DC 20460, telephone (202) 564–9945, or susanke.greg@epa.gov.

Dated: March 6, 2012.

Lek Kadeli,

Acting Assistant Administrator, Office of Research and Development.

[FR Doc. 2012–13184 Filed 5–30–12; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–9679–4]

Establishment of the Great Lakes Advisory Board (GLAB)

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice; establishment of a Federal Advisory Committee.

SUMMARY: As required by section 9(a)(2) of the Federal Advisory Committee Act, we are giving notice that EPA is establishing the Great Lakes Advisory Board (GLAB). The purpose of the GLAB is to provide advice to the Administrator in her capacity as Chair of the Inter-Agency Task Force established per Executive Order 13340 (May 18, 2004), on matters related to Great Lakes restoration and protection. The major objectives will be to provide advice and recommendations on: Great Lakes protection and restoration policy; long term goals and objectives for Great Lakes protection and restoration; and annual priorities to protect and restore the Great Lakes that may be used to help inform budget decisions.

EPA has determined that this federal advisory committee is in the public interest and will assist the EPA in performing its duties and responsibilities. Copies of the GLAB's charter will be filed with the appropriate congressional committees and the Library of Congress.

FOR FURTHER INFORMATION CONTACT: Rita Cestaric, U.S. Environmental Protection Agency, 77 W. Jackson, Chicago, IL 60604, Email address: *cestaric.rita@epa.gov,* Telephone number: (312) 886–6815.

SUPPLEMENTARY INFORMATION: The GLAB will be composed of approximately fifteen (15) members who will serve as representative members, Regular Government Employees (RGEs), or Special Government Employees (SGEs). The GLAB expects to meet in person or by electronic means (e.g., telephone, videoconference, webcast, etc.) approximately two (2) times a year, or as needed and approved by the Designated Federal Officer (DFO). Meetings will be held in the Great Lakes region and Washington, DC. The GLAB will be examined annually and will exist until the EPA determines that the GLAB is no longer needed. The charter will be in effect for two years from the date it is filed with Congress. After the initial two-year period, the charter may be renewed as authorized in accordance with Section 14 of FACA (5 U.S.C. App. 2 § 14).

Membership: Nominations for membership will be solicited through the **Federal Register** and other sources. In selecting members, EPA will consider candidates representing a broad range of interests relating to the Great Lakes, including, but not limited to, environmental groups, business, agricultural groups, citizen groups, environmental justice groups, foundations, academia and state, local and tribal governments. In selecting members, EPA will consider the differing perspectives and breadth of collective experience needed to address the EPA's charge.

Dated: May 17, 2012.

Susan Hedman,

Great Lakes National Program Manager.

[FR Doc. 2012–13186 Filed 5–30–12; 8:45 am]

BILLING CODE 6560–50–P

FEDERAL COMMUNICATIONS COMMISSION

Information Collections Being Submitted for Review and Approval to the Office of Management and Budget

AGENCY: Federal Communications Commission.

ACTION: Notice and request for comments.

SUMMARY: The Federal Communications Commission (FCC), as part of its continuing effort to reduce paperwork burdens, invites the general public and other Federal agencies to take this opportunity to comment on the following information collection, as required by the Paperwork Reduction Act (PRA) of 1995. 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 PRA that does not display a valid control number. Comments are requested concerning whether the proposed collection of information is necessary for the proper performance of the functions of the Commission, including whether the information shall have practical utility; the accuracy of the Commission's burden estimate; ways to enhance the quality, utility, and clarity of the information collected; ways to minimize the burden of the collection of information on the respondents, including the use of automated collection techniques or other forms of information technology; and ways to further reduce the information collection burden on small business concerns with fewer than 25 employees. The FCC may not conduct or sponsor a collection of information unless it displays a currently valid control number. No person shall be subject to any penalty for failing to comply with a collection of information subject to the PRA that does not display a valid Office of Management and Budget (OMB) control number.

DATES: Written comments should be submitted on or before July 2, 2012. 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 contacts below as soon as possible.

ADDRESSES: Direct all PRA comments to Nicholas A. Fraser, OMB, via fax 202–395–5167, or via email *Nicholas_A._Fraser@omb.eop.gov;* and to Cathy Williams, FCC, via email *PRA@fcc.gov* <*mailto:PRA@fcc.gov*> and to *Cathy.Williams@fcc.gov.* Include in the comments the OMB control number as shown in the **SUPPLEMENTARY INFORMATION** section below.

FOR FURTHER INFORMATION CONTACT: For additional information or copies of the information collection, contact Cathy Williams at (202) 418–2918. To view a copy of this information collection request (ICR) submitted to OMB: (1) Go to the Web page <*http://www.reginfo.gov/public/do/PRAMain*>, (2) look for the section of the Web page called ''Currently Under Review,'' (3) click on the downward-pointing arrow in the ''Select Agency'' box below the ''Currently Under Review'' heading, (4) select ''Federal Communications Commission'' from the list of agencies presented in the ''Select Agency'' box, (5) click the ''Submit'' button to the right of the ''Select Agency'' box, (6) when the list of FCC ICRs currently under review appears, look for the OMB control number of this ICR and then click on the ICR Reference Number. A copy of the FCC submission to OMB will be displayed.

SUPPLEMENTARY INFORMATION:

OMB Control Number: 3060–1146.

Title: Implementation of the Twenty-first Century Communications and Video Accessibility Act of 2010, Section 105, Relay Services for Deaf-Blind Individuals, CG Docket No. 10–210.

Form Number: N/A.

Type of Review: Revision of a currently approved collection.

Respondents: Individuals or households; businesses or other for-profit entities; not-for-profit Institutions; Federal government; State, local or tribal governments.

Number of Respondents and Responses: 106 respondents; 989 responses.

Estimated Time per Response: 1 to 120 hours.

Frequency of Response: Annual, on occasion, one-time, monthly, and semi-annually reporting requirements; record keeping requirement; third party disclosure requirement.

Obligation to Respond: Required to obtain or retain benefit. The statutory authority for the information collections is contained in 47 U.S.C. 154, 254(k); sections 403(b)(2)(B), (c), Public Law 104–104, 110 Stat. 56. Interpret or apply 47 U.S.C. 201, 218, 222, 225, 226, 228, 254(k), and 620.

Total Annual Burden: 21,465 hours.

Total Annual Cost: None.

Nature and Extent of Confidentiality: Confidentiality is an issue to the extent that individuals and households provide personally identifiable information (PII), which is covered under the FCC's system of records notice (SORN), FCC/CGB–3, ''National Deaf-Blind Equipment distribution Program.'' As required by the Privacy Act, 5 U.S.C. 552a, the Commission also published a SORN, FCC/CGB–3 ''National Deaf-Blind Equipment Distribution Program,'' in the **Federal Register** on January 19, 2012 (77 FR 2721) which became effective on February 28, 2012. Also, the Commission is in the process of preparing the new privacy impact assessment (PIA) related to the PII covered by these information collections, as required by OMB's Memorandum M–03–22 (September 26, 2003) and by the Privacy Act, 5 U.S.C. 552a.

Privacy Impact Assessment: Yes. The Privacy Impact Assessment (PIA) was completed on June 28, 2007. It may be reviewed at: *http:www.fcc.gov/omd/privacyact/Privacy_Impact_Assessment.html.* The Commission is in the process of updating the PIA to incorporate various revisions made to the SORN and is in the process of preparing a new SORN to cover the PII collected related thereto, as stated above.

Needs and Uses: On April 6, 2011, in document FCC 11–56, the Commission released a Report and Order adopting final rules to implement section 719 of the Communications Act of 1934 (the Act), as amended, which was added to the Act by the ''Twenty-First Century Communications and Video Accessibility Act of 2010'' (CVAA). See Public Law 111–260, § 105. Section 719 of the Act authorizes up to $10 million annually from the Interstate Telecommunications Relay Service Fund (TRS Fund) to support eligible programs that distribute equipment designed to make telecommunications service, Internet access service, and advanced communications accessible by low-income individuals who are deaf-blind. Specifically, the rules adopted in document FCC 11–56 established the National Deaf-Blind Equipment Distribution Program (NDBEDP) as a pilot program for two years with an option to extend the program for one additional year. The rules adopted in document FCC 11–56 have the following information collection requirements:

(a) State equipment distribution programs, other public programs, and private entities may submit applications for NDBEDP certification to the Commission. For each state, the Commission will certify a single program as the sole authorized entity to participate in the NDBEDP and receive reimbursement from the TRS Fund.

(b) Each program certified under the NDBEDP must submit certain program-related data electronically to the Commission, as instructed by the NDBEDP Administrator, every six months, commencing with the start of the pilot program.

(c) Each program certified under the NDBEDP must retain all records associated with the distribution of equipment and provision of related services under the NDBEDP for two years following the termination of the pilot program.

(d) Each program certified under the NDBEDP must obtain verification that NDBEDP applicants meet the definition of an individual who is deaf-blind.

(e) Each program certified under the NDBEDP must obtain verification that NDBEDP applicants meet the income eligibility requirements.

(f) Programs certified under the NDBEDP shall be reimbursed for the cost of equipment that has been distributed to eligible individuals and authorized related services, up to the state's funding allotment under this program. Within 30 days after the end of each six-month period of the Fund Year, each program certified under the NDBEDP pilot must submit documentation that supports its claim for reimbursement of the reasonable costs of equipment and related services.

On March 20, 2012 in document DA 12–430, the Commission released an order to conditionally waive the requirement in section (f), above, for NDBEDP certified programs to submit reimbursement claims at the end of each six-month period of the TRS Fund Year to permit certified programs to submit reimbursement claims as frequently as monthly. Each certified program that wishes to take advantage of this waiver will be permitted to elect a monthly or quarterly reimbursement schedule, must notify the TRS Fund Administrator of its election at the start of each Fund Year, and must maintain that schedule for the duration of the Year.

OMB Control Number: 3060–1162.

Title: Closed Captioning of Video Programming Delivered Using Internet Protocol, and Apparatus Closed Caption Requirements.

Form Number: N/A.

Type of Review: Revision of a currently approved collection.

Respondents: Individuals or households; businesses or other for-profit entities; not-for-profit institutions.

Number of Respondents and Responses: 1,762 respondents; 4,684 responses.

Estimated Time per Response: 0.084 to 10 hours.

Frequency of Response: One time and on occasion reporting requirements; recordkeeping requirement; third-party disclosure requirement.

Obligation to Respond: Mandatory; Required to obtain or retain benefits. The statutory authority for this information collection is contained in the Twenty-First Century Communications and Video Accessibility Act of 2010, Public Law 111–260, 124 Stat. 2751, and Sections 4(i), 4(j), 303, 330(b), 713, and 716 of the Communications Act of 1934, as amended, 47 U.S.C. 154(i), 154(j), 303, 330(b), 613, and 617.

Total Annual Burden: 11,685 hours.

Total Annual Cost: $307,800.

Privacy Act Impact Assessment: Yes. The Privacy Impact Assessment (PIA) was completed on June 28, 2007. It may be reviewed at: *http://www.fcc.gov/omd/privacyact/Privacy_Impact_Assessment.html.* The Commission is in the process of updating the PIA to incorporate various revisions made to the SORN.

Nature and Extent of Confidentiality: Some assurances of confidentiality are being provided to the respondents.

Parties filing petitions for exemption based on economic burden, requests for Commission determinations of technical feasibility and achievability, requests for purpose-based waivers, or responses to complaints alleging violations of the Commission's rules may seek confidential treatment of information they provide pursuant to the

Commission's existing confidentiality rules. See 47 CFR 0.459.

The Commission is not requesting that individuals who file complaints alleging violations of the Commission's rules (complainants) submit confidential information (e.g., credit card numbers, social security numbers, or personal financial information) to the Commission. The Commission requests that complainants submit their names, addresses, and other contact information, which Commission staff needs to process complaints. Any use of this information is covered under the routine uses listed in the Commission's SORN, FCC/CGB–1, ''Informal Complaints and Inquiries.''

The PIA that the FCC completed on June 28, 2007 gives a full and complete explanation of how the FCC collects, stores, maintains, safeguards, and destroys PII, as required by OMB regulations and the Privacy Act, 5 U.S.C. 552a. The PIA may be viewed at: *http://www.fcc.gov/omd/privacyact/Privacy-Impact-Assessment.html.*

Also, the Commission will prepare a revision to the SORN and PIA to cover the PII collected related to this information collection, as required by OMB's Memorandum M–03–22 (September 26, 2003) and by the Privacy Act, 5 U.S.C. 552a.

Needs and Uses: On January 13, 2012, in document FCC 12–9, the Commission released a Report and Order adopting final rules to implement sections 303, 330(b), and 713 of the Communications Act of 1934 (the Act), as amended by the ''Twenty-First Century Communications and Video Accessibility Act of 2010'' (CVAA). See Public Law 111–260, §§ 202 and 203. The Commission also released an Erratum thereto on January 30, 2012. Pursuant to Section 202 of the CVAA, the Report and Order adopts rules governing the closed captioning requirements for the owners, providers, and distributors of video programming delivered using Internet protocol (IP). Pursuant to Section 203 of the CVAA, the Report and Order adopts rules governing the closed captioning capabilities of certain apparatus on which consumers view video programming.

The following rule sections and other requirements contain revised information collection requirements for which the Commission is seeking approval from the Office of Management and Budget (OMB):

(a) 47 CFR 79.4(c)(1)(ii) and 47 CFR 79.4(c)(2)(ii) require video programming owners (VPOs) and video programming distributors and providers (VPDs) to agree upon a mechanism to inform VPDs on an ongoing basis whether video programming is subject to the IP closed captioning requirements. The Commission considered and rejected adopting a single specific mechanism that could impose greater information collection burdens on small businesses. 47 CFR 79.4(c)(2)(ii) requires VPDs to make a good faith effort to identify video programming subject to the IP closed captioning requirements using the agreed upon mechanism. A VPD may rely in good faith on a certification by a VPO that video programming need not be captioned if: (A) The certification includes a clear and concise explanation of why captioning is not required; and (B) the VPD is able to produce the certification to the Commission in the event of a complaint. VPDs may seek Commission determinations that other proposed mechanisms provide adequate information for them to rely on the mechanisms in good faith.

(b) 47 CFR 79.4(c)(2)(iii) requires VPDs to make contact information available to end users for the receipt and handling of written IP closed captioning complaints. The contact information required for written complaints shall include the name of a person with primary responsibility for IP captioning issues and who can ensure compliance with the IP closed captioning rules. In addition, this contact information shall include the person's title or office, telephone number, fax number, postal mailing address, and email address. VPDs must keep this information current and update it within 10 business days of any change.

(c) 47 CFR 79.4(d)(1) permits VPOs and VPDs to petition the Commission for a full or partial exemption from the IP closed captioning requirements, which the Commission may grant upon a finding that the requirements would be economically burdensome. 47 CFR 79.4(d)(2) requires the petitioner to support a petition for exemption with sufficient evidence to demonstrate that compliance with the requirements for closed captioning of IP-delivered video programming would be economically burdensome. The term ''economically burdensome'' means imposing significant difficulty or expense. The Commission will consider the following factors when determining whether the requirements for closed captioning of IP-delivered video programming would be economically burdensome: (i) The nature and cost of the closed captions for the programming; (ii) the impact on the operation of the VPD or VPO; (iii) the financial resources of the VPD or VPO; and (iv) the type of operations of the VPD or VPO. 47 CFR 79.4(d)(3) provides that, in addition to these factors, the petitioner must describe any other factors it deems relevant to the Commission's final determination and any available alternatives that might constitute a reasonable substitute for the IP closed captioning requirements including, but not limited to, text or graphic display of the content of the audio portion of the programming. The Commission will evaluate economic burden with regard to the individual outlet. 47 CFR 79.4(d)(4) requires the petitioner to electronically file its petition for exemption, and all subsequent pleadings related to the petition. 47 CFR 79.4(d)(6) permits any interested person to electronically file comments or oppositions to the petition within 30 days after release of the public notice of the petition. Within 20 days after the close of the period for filing comments or oppositions, the petitioner may reply to any comments or oppositions filed. 47 CFR 79.4(d)(7) requires persons who file comments or oppositions to the petition to serve the petitioner with copies of those comments or oppositions and to include a certification that the petitioner was served with a copy. Any petitioner filing a reply to comments or oppositions must serve the commenting or opposing party with a copy of the reply and must include a certification that the party was served with a copy.

Comments or oppositions and replies shall be served upon a party, its attorney, or its other duly constituted agent by delivering or mailing a copy to the party's last known address or by sending a copy to the email address last provided by the party, its attorney, or other duly constituted agent. 47 CFR 79.4(d)(8) provides that, upon a finding of good cause, the Commission may lengthen or shorten any comment period and waive or establish other procedural requirements. 47 CFR 79.4(d)(9) requires persons filing petitions and responsive pleadings to include a detailed, full showing, supported by affidavit, of any facts or considerations relied on. Overall, while there is some burden associated with requesting an exemption, when granted, an exemption will relieve the entity from complying with the IP closed captioning requirements.

(d) 47 CFR 79.4(e)(1) provides that complaints concerning an alleged violation of the IP closed captioning requirements shall be filed in writing with the Commission or with the VPD responsible for enabling the rendering or pass through of the closed captions for the video programming within sixty (60) days after the date the complainant experienced a problem with captioning. A complaint filed with the Commission must be directed to the Consumer and

Governmental Affairs Bureau and submitted through the Commission's online informal complaint filing system, U.S. Mail, overnight delivery, or facsimile. 47 CFR 79.4(e)(2) sets forth certain information that a complaint should include. 47 CFR 79.4(e)(3) states that, if a complaint is filed first with the Commission, the Commission will forward complaints satisfying the above requirements to the named VPD and/or VPO, as well as to any other VPD and/or VPO that Commission staff determines may be involved. The VPD and/or VPO must respond in writing to the Commission and the complainant within 30 days after receipt of the complaint from the Commission. 47 CFR 79.4(e)(4) states that, if a complaint is filed first with the VPD, the VPD must respond in writing to the complainant within thirty (30) days after receipt of a closed captioning complaint. If a VPD fails to respond to the complainant within thirty (30) days, or the response does not satisfy the consumer, the complainant may file the complaint with the Commission within thirty (30) days after the time allotted for the VPD to respond. If a consumer re-files the complaint with the Commission and the complaint satisfies the above requirements, the Commission will forward the complaint to the named VPD, as well as to any other VPD and/or VPO that Commission staff determines may be involved. The VPD and/or VPO must then respond in writing to the Commission and the complainant within 30 days after receipt of the complaint from the Commission. 47 CFR 79.4(e)(5) requires VPDs and/or VPOs, in response to a complaint, to file with the Commission sufficient records and documentation to prove that the responding entity was (and remains) in compliance with the Commission's rules. If the responding entity admits that it was not or is not in compliance with the Commission's rules, it shall file with the Commission sufficient records and documentation to explain the reasons for its noncompliance, show what remedial steps it has taken or will take, and show why such steps have been or will be sufficient to remediate the problem. 47 CFR 79.4(d)(6) permits the Commission to request additional information from any relevant entities when, in the estimation of Commission staff, such information is needed to investigate the complaint or adjudicate potential violation(s) of Commission rules. When the Commission requests additional information, parties to which such requests are addressed must provide the requested information in the manner and within the time period the Commission specifies. Overall, while the complaint procedures impose an information collection burden, the requirement for VPDs to publish contact information, described above, and to respond to consumer complaints provides an opportunity for VPDs to resolve complaints without Commission involvement.

(e) Under the CVAA, the requirements of Section 203 only apply to the extent they are ''technically feasible.'' Parties may raise technical infeasibility as a defense to a complaint or, alternatively, may file a request for a ruling under Section 1.41 of the Commission's rules before manufacturing or importing the product.

(f) 47 CFR 79.103(b)(3)(i) permits manufacturers of apparatus that use a picture screen of less than 13 inches in size to petition the Commission for a full or partial exemption from the closed captioning requirements pursuant to Section 1.41 of the Commission's rules, which the Commission may grant upon a finding that the requirements are not achievable. Such manufacturers may also assert that such apparatus is fully or partially exempt as a response to a complaint, which the Commission may dismiss upon a finding that the requirements are not achievable. 47 CFR 79.103(b)(3)(ii) requires the petitioner or respondent to support a petition for exemption or a response to a complaint with sufficient evidence to demonstrate that compliance with the requirements is not ''achievable'' where ''achievable'' means with reasonable effort or expense. The rule further sets forth certain factors that the Commission will consider when determining whether the requirements are not ''achievable.''

(g) 47 CFR 79.103(b)(4) permits manufacturers of apparatus to petition the Commission for a full or partial waiver of the closed captioning requirements, which the Commission may grant upon a finding that the apparatus meets one of the following provisions: (i) The apparatus is primarily designed for activities other than receiving or playing back video programming transmitted simultaneously with sound; or (ii) the apparatus is designed for multiple purposes, capable of receiving or playing back video programming transmitted simultaneously with sound but whose essential utility is derived from other purposes.

(h) The Report and Order also established procedures for the filing of written complaints alleging violations of the Commission's rules requiring apparatus designed to receive, play back, or record video programming to be equipped with built-in closed caption decoder circuitry or capability designed to display closed captions. The Commission set forth information that such complaints should include. A written complaint filed with the Commission must be transmitted to the Consumer and Governmental Affairs Bureau through the Commission's online informal complaint filing system, U.S. Mail, overnight delivery, or facsimile. The Commission may forward such complaints to the named manufacturer or provider, as well as to any other entity that Commission staff determines may be involved, and may request additional information from any relevant parties when, in the estimation of Commission staff, such information is needed to investigate the complaint or adjudicate potential violations of Commission rules.

Federal Communications Commission.

Bulah P. Wheeler,

Deputy Manager, Office of the Secretary, Office of Managing Director.

[FR Doc. 2012–13129 Filed 5–30–12; 8:45 am]

BILLING CODE 6712–01–P

FEDERAL COMMUNICATIONS COMMISSION

[AU Docket No. 12–25; DA 12–641 and DA 12–721]

Mobility Fund Phase I Auction Scheduled for September 27, 2012; Notice and Filing Requirements and Other Procedures for Auction 901

AGENCY: Federal Communications Commission.

ACTION: Notice.

SUMMARY: In this document, the Wireless Telecommunications Bureau (WTB) and the Wireline Competition Bureau (WCB) (collectively, the Bureaus) announce the procedures and filing requirements for a reverse auction to award $300 million in one-time Mobility Fund Phase I support scheduled to commence on September 27, 2012. The Bureaus also announce the availability of eligible area data in various formats.

DATES: Short-form applications are due prior to 6 p.m. on July 11, 2012.

FOR FURTHER INFORMATION CONTACT: *Wireless Telecommunications Bureau, Auctions and Spectrum Access Division:* for Mobility Fund Phase I questions: Sayuri Rajapakse or Stephen Johnson at (202) 418–0660; for auction process questions: Lisa Stover at (717) 338–2868. *Wireline Competition Bureau, Telecommunications Access Policy Division:* for general universal service questions: Alex Minard at (202) 418–7400.

SUPPLEMENTARY INFORMATION: This is a summary of two public notices related to the auction for Mobility Fund Phase I support (Auction 901): (1) The *Auction 901 Procedures Public Notice* released on May 2, 2012, and (2) a public notice released on May 8, 2012, announcing the availability of additional formats for data regarding the areas eligible for support in Auction 901. Both public notices and other related Commission documents may be purchased from the Commission's duplicating contractor, Best Copy and Printing, Inc. (BCPI), 445 12th Street SW., Room CY–B402, Washington, DC 20554, telephone 202–488–5300, fax 202–488–5563, or you may contact BCPI at its Web site: *http://www.BCPIWEB.com.* When ordering documents from BCPI, please provide the appropriate FCC document number, for example, DA 12–641 or DA 12–721. Both public notices and other related documents also are available on the Internet at the Commission's Web site: *http://wireless.fcc.gov/auctions/901/* or by using the search function for AU Docket No. 12–25 on the Commission's Electronic Comment Filing System (ECFS) Web page at *http://www.fcc.gov/cgb/ecfs/.*

I. General Information

A. Introduction and Summary

1. The Bureaus establish the procedures that will be used for the reverse auction that will award $300 million in one-time Mobility Fund Phase I support. This auction, designated as Auction 901, is scheduled to be held on September 27, 2012. The *Auction 901 Procedures Public Notice* establishes the procedures, terms, and conditions governing Auction 901 and the post-auction application process, and provides other important information for parties that wish to seek Mobility Fund Phase I support.

2. Auction 901 will award one-time support to carriers that commit to provide third-generation (3G) or better mobile voice and broadband services in census blocks where such services are unavailable. Mobility Fund Phase I support will be allocated to maximize the road miles covered by new mobile services without exceeding the budget of $300 million. Winning bidders will be obligated to choose whether to deploy 3G service within two years or fourth-generation (4G) service within three years of the award of support. The term 3G refers to mobile wireless services that provide voice telephony service on networks that also provide services such as Internet access and email. 4G services are those capable of meeting or exceeding certain data rates, as discussed below.

3. Auction 901 will be the first auction to award high-cost universal service support through competitive bidding. The *USF/ICC Transformation Order,* 76 FR 73830, November 29, 2011 and 76 FR 81562, December 28, 2011, established the Mobility Fund as a universal service support mechanism dedicated expressly to mobile services and adopted rules for distribution of the $300 million initial budget through Mobility Fund Phase I. In the *USF/ICC Transformation Order,* the Commission delegated authority to the Bureaus to implement Mobility Fund Phase I, including the authority to prepare for and conduct an auction and administer program details. On February 2, 2012, the Bureaus released the *Auction 901 Comment Public Notice,* 77 FR 7152, February 10, 2012, which identified a preliminary list of census blocks potentially eligible for Mobility Fund Phase I support and sought comment on whether census blocks should be added or removed from the list of potentially eligible census blocks, on the details of auction procedures, and on certain related program requirements for Auction 901. The Bureaus considered 69 separate filings in response to the *Auction 901 Comment Public Notice.*

4. In the *Auction 901 Procedures Public Notice,* The Bureaus, among other things: (1) Provide the final list of census blocks eligible for Mobility Fund Phase I support in Auction 901; (2) conclude that, to establish the number of qualifying road miles associated with each eligible census block, three additional Census road categories will be added to the three categories of roads proposed in the *Auction 901 Comment Public Notice;* (3) conclude that Auction 901 will be conducted as a single round, sealed bid auction; (4) provide for bidding on predefined aggregations of eligible census blocks by census tracts, except in Alaska, where bidding will be permitted on individual eligible census blocks; (5) require that each winning bidder provide coverage, consistent with the performance requirements of the rules adopted in the *USF/ICC Transformation Order,* to a minimum of 75 percent of the road miles in each census tract for which it wins support, calculated as the total of the road miles in the eligible census blocks in the tract; and (6) permit winning bidders to demonstrate that they offer supported services at rates comparable to those in urban areas by offering one stand-alone voice and one data plan in supported area(s) that match plans in urban areas, i.e., in top 100 Cellular Market Areas (CMAs), and cost no more than the matching plans.

5. Moreover, the *Auction 901 Procedures Public Notice* reviews important Mobility Fund Phase I program requirements, including eligibility requirements for participation and the public interest obligations of winning bidders; describes in detail pre-auction procedures and deadlines, including auction application requirements; explains requirements and details related to the structure and procedures for bidding as outlined above; and provides an overview of the post-auction procedures, requirements, and deadlines, including information on the post-auction application and on payment requirements that will be used to enforce carriers' obligations.

B. Overview of Mobility Fund Phase I

i. Background

6. In the *USF/ICC Transformation Order,* the Commission comprehensively reformed and modernized the high-cost component of the Universal Service Fund (USF) to help ensure the universal availability of fixed and mobile communication networks capable of providing voice and broadband services, and established a universal service support mechanism dedicated expressly to mobile services—the Mobility Fund.

7. Phase I of the Mobility Fund will provide up to $300 million in one-time support to address gaps in mobile services availability by supporting the build-out of current- and next-generation mobile networks in areas where these networks are unavailable. The support offered under Phase I of the Mobility Fund is in addition to any ongoing support provided under existing high-cost universal service program mechanisms. Phase II of the Mobility Fund will provide $500 million annually for ongoing support of mobile services. The Commission sought comment on the details for Mobility Fund Phase II in the Further Notice of Proposed Rulemaking adopted in the *USF/ICC Transformation Order.*

8. The goal for Mobility Fund Phase I is to extend the availability of mobile voice and broadband service on networks that provide 3G or better performance and to accelerate the deployment of 4G wireless networks in areas where it is cost effective to do so with one-time support. To maximize coverage in eligible unserved areas within the established budget of $300 million, the *USF/ICC Transformation Order* established general rules for a reverse auction to identify those areas where additional investment can make

as large a difference as possible, in a transparent, simple, speedy, and effective way. In this reverse auction, bidders will indicate the amount of one-time support they require to deploy service meeting the defined performance standard in given unserved areas. Because the auction will generally award support based on the lowest per-unit bid amount irrespective of geographic area, bidders will compete not only against other carriers that may be seeking support in the same areas, but also against carriers bidding for support in other areas nationwide. Support will be awarded based on the lowest bid amounts submitted, but will not be awarded to more than one provider per area. Successful bidders will be awarded support for an area at the price they bid.

ii. Identification of Unserved Census Blocks Eligible for Mobility Fund Support

9. In the *USF/ICC Transformation Order,* the Commission decided to target Mobility Fund Phase I support to census blocks without 3G or better service at the geometric center of the block, referred to as the centroid, and concluded that American Roamer data is the best available data source for determining where such service is unavailable. (The *Auction 901 Procedures Public Notice* continues to refer to the data as American Roamer data, even though the company has since changed its name to Mosaik Solutions.) In the *USF/ICC Transformation Order,* the Commission concluded that it would consider any census block in the 2010 Census as unserved—and thus eligible for support—if an analysis of the American Roamer data indicated that the centroid is not covered by networks using EV–DO, EV–DO Rev A, or UMTS/HSPA or better.

10. In the *Auction 901 Comment Public Notice,* the Bureaus concluded that January 2012 American Roamer data was the most recently available for the purpose of doing an analysis to identify eligible census blocks and described the methodology for identifying potentially eligible blocks. The Bureaus used geographic information system (GIS) software to determine whether the American Roamer data show 3G or better wireless coverage at the centroid of each block. If the American Roamer data did not show such coverage, the block was determined to be unserved. In the *Auction 901 Updated Blocks Public Notice,* 77 FR 9655, February 17, 2012, the Bureaus identified potentially eligible unserved blocks based on their analysis of 2010 Census data and January 2012 American Roamer data. Because Mobility Fund Phase I support will be awarded based on bid amounts and the number of road miles in each unserved census block, the list of potentially eligible census blocks did not include any unserved census blocks without road miles. The updated list consisted of 467,604 census blocks that lacked 3G or better service at the centroid of the block.

11. Pursuant to the *USF/ICC Transformation Order,* the Bureaus will also make ineligible for support census blocks for which, notwithstanding the absence of 3G service, any provider has made a regulatory commitment to provide 3G or better wireless service, or has received a funding commitment from a federal executive department or agency in response to the carrier's commitment to provide 3G or better wireless service. Such federal funding commitments include, but are not limited to, those made under the Broadband Technology Opportunities Program (BTOP) and Broadband Initiatives Program (BIP) authorized by the American Recovery and Reinvestment Act of 2009 (ARRA).

12. The Commission established certain bidder-specific restrictions. Specifically, each applicant for Mobility Fund Phase I support is required to certify that it will not seek support for any areas for which it has made a public commitment to deploy, by December 31, 2012, 3G or better wireless service. In determining whether an applicant has made such a public commitment, the Bureaus anticipated that they would consider any public statement made with some specificity as to both geographic area and time period. This restriction will not prevent a bidder from seeking and receiving support for an unserved area for which another provider has made such a public commitment.

13. In the *USF/ICC Transformation Order,* the Commission, responding to concerns about potential errors in determining coverage of a particular area, provided for a limited timeframe for challenges to those initial determinations. The Commission explained that it would make public a list of unserved areas as part of the pre-auction process and afford parties a reasonable opportunity to respond by demonstrating that specific areas identified as unserved are actually served and/or that additional unserved areas should be included. In the *Auction 901 Comment Public Notice,* the Bureaus therefore asked commenters to indicate which blocks included in the revised list should not be eligible for Mobility Fund Phase I support and provide supporting evidence. Similarly, the Bureaus asked commenters to indicate which blocks not included in the revised list should be eligible for support and provide supporting evidence.

14. The Bureaus received numerous comments, reply comments, *ex parte* and other submissions relating to census block eligibility. Three states requested that the Bureaus add census blocks to the revised list based on State Broadband Initiative data. Five BIP and/or BTOP awardees submitted comments requesting that the Bureaus remove census blocks. Twenty-two other providers also requested that the Bureaus either add or remove census blocks from their updated list of potentially eligible blocks.

15. Three state agencies requested that the Bureaus include census blocks that the states identify as unserved based on the State Broadband Initiative data gathered by the individual states for the National Broadband Map. In the *USF/ICC Transformation Order,* the Commission rejected the use of the National Broadband Map generally because of inconsistencies in the initial phase relating to wireless services data. While the Bureaus appreciate that data submitted for and displayed in the National Broadband Map may have improved, the Bureaus conclude that the states did not provide enough information to justify a conclusion that the states' data is more reliable than the Bureaus' analysis of American Roamer and other data, which the Commission determined to use as a consistent basis for determining eligible census blocks across all states. The Bureaus therefore decline to add as eligible census blocks those listed by the three state agencies in their filings.

16. In light of the Commission's determination to make ineligible for support census blocks where a carrier had made a commitment to provide 3G or better mobile service in return for a federal funding commitment (such as those made under BIP and BTOP), the Bureaus requested information on awards proposing mobile wireless projects using 3G or better technology. In response, the U.S. Department of Agriculture's Rural Utilities Service (USDA RUS) and the U.S. Department of Commerce's National Telecommunications and Information Administration (NTIA) submitted information on the location of their BIP and BTOP awards. Five carriers also submitted comments listing census blocks to be removed from the Bureaus' list of potentially eligible blocks based

on their receipt of BIP and/or BTOP awards to provide 3G or better service.

17. USDA RUS provided the Bureaus with a list of Census 2000 census blocks associated with BIP awards for mobile wireless projects. After converting the data to 2010 census blocks and comparing the results to the 2010 census blocks submitted by the three carriers claiming BIP awards, the Bureaus find that the blocks submitted by the carriers were also reported on the list. This consistency leads the Bureaus to conclude that the full list of census blocks receiving BIP awards should be removed from the list of eligible census blocks to comply with the *USF/ICC Transformation Order*. As a result, the Census 2000 census blocks which relate to seven awards made to six parties, including three that commented in this proceeding, will be converted to 2010 census blocks as described and removed.

18. NTIA provided the Bureaus with a list of Census 2000 census tracts associated with BTOP awards potentially for mobile wireless projects. The BTOP list may be over inclusive because the list describes areas at the census tract rather than the census block level, and it may include middle mile infrastructure projects rather than projects expressly expanding mobile services. The Bureaus compared this list with the 2010 equivalents of the census tracts associated with the 2010 census blocks submitted by the three commenters claiming BTOP awards. The census block data submitted by two of the three commenters corresponded closely to areas identified on the list. Based on that correspondence, the Bureaus remove the census blocks submitted by the two commenters from the list of eligible census blocks. However, because the likely over inclusiveness of the submitted data reduces the Bureaus' ability to ensure that they would be targeting areas with planned expansion of 3G or better coverage, the Bureaus did not remove all of the areas on the list from consideration for Mobility Fund Phase I support. Further, the Bureaus decline to remove the blocks that a third commenter identified as associated with a BTOP award, because the award and areas referenced by the commenter are not included in the list.

19. The Bureaus also received comments from 22 carriers requesting changes to their list of potentially eligible blocks—either removals based on assertions that census blocks listed as potentially eligible currently have 3G or better service (or would in the relatively near future) or additions based on assertions that census blocks not listed as potentially eligible actually lack 3G or better service. First, the Bureaus note that three parties filed comments listing census blocks for removal from the potentially eligible list based on assertions, at least in part, that they would be covered in the future, i.e., after the close of the record on March 26, 2012. The Bureaus conclude that they will not make census blocks ineligible based on these assertions. Pursuant to the *USF/ICC Transformation Order,* the Bureaus provided parties with an opportunity to demonstrate that specific areas identified as unserved are actually served or that parties had made a regulatory commitment to serve particular areas. The Bureaus finds that these assertions of coverage after the close of the record do not demonstrate actual service or a regulatory commitment that should be reflected in the Bureaus final list of eligible census blocks. Although two carriers also claimed that they currently provide service with respect to some of their listed census blocks, the Bureaus reject their requested exclusions because they do not differentiate between current and future coverage in their submissions.

20. The Bureaus received comments from 15 carriers identifying census blocks for removal and/or addition to the list of potentially eligible census blocks based on demonstrations of current coverage at the centroid, or the lack thereof, in the form of maps, discussions of drive tests, explanation of methodologies for determining coverage and in numerous cases, certifications by one or more individuals as to the veracity of the material provided. The Bureaus find these demonstrations to be sufficiently credible and convincing to meet the requirements of the *USF/ICC Transformation Order* and incorporate the requested changes in the final list of eligible census blocks, to the extent that they contain road miles in any of the six categories identified by the Bureaus in the *Auction 901 Procedures Public Notice.*

21. Finally, the Bureaus received comments from five carriers listing census blocks for removal from the potentially eligible list based on bare assertions that their own coverage maps show they serve census blocks on the Bureaus potentially eligible list. In contrast to the submissions of the 15 carriers, these five did not provide any information regarding the basis for their assertions. Reply commenters challenged several such submissions as inadequate. The Bureaus conclude that these assertions without supporting evidence do not demonstrate actual service, as envisioned by the *USF/ICC Transformation Order,* that provides a basis for the Bureaus to depart from their determination of potentially eligible census blocks.

22. The list of census blocks released with the *Auction 901 Procedures Public Notice* is the Bureaus' final list of eligible census blocks that were identified by analyzing U.S. Census data, January 2012 American Roamer data, and information submitted by third parties. The difference between this list and the list provided with the *Auction 901 Updated Blocks Public Notice* is that the Bureaus have removed and added blocks based on the comments of the 15 carriers that provided sufficiently credible and convincing demonstrations, the Bureaus removed blocks based on BTOP and BIP awards, and the Bureaus removed blocks that did not have road miles in any of the six road categories. Accordingly, the list of census blocks the Bureaus released in the *Auction 901 Procedures Public Notice* contains the final determinations with respect to the areas eligible for Mobility Fund Phase I support. These census blocks will, in most cases, be aggregated into their associated census tracts for bidding purposes. Concurrent with the release of the *Auction 901 Procedures Public Notice,* the Bureaus released an interactive map of the eligible census blocks. The map is a visual representation of data from the Attachment A files, which contain more information and generally more detail than is displayed on the map. The map is available at *http://wireless.fcc.gov/auctions/901/* and at *http://www.fcc.gov/maps/*. The Bureaus have also announced the availability of a spreadsheet of biddable geographic areas for Auction 901 and geographic information system (GIS) data for the census blocks eligible for Mobility Fund Phase I support to be offered in Auction 901. These data in additional formats are available at *http://wireless.fcc.gov/auctions/901/.*

23. The Bureaus remind those interested in seeking Mobility Fund Phase I support that applicants for Auction 901 are required to certify that they will not seek support for any areas in which they have made a public commitment to deploy 3G or better service by December 31, 2012.

iii. Establishing Unserved Road Mile Units

24. In the *Auction 901 Comment Public Notice,* the Bureaus proposed to establish road mile units based on three road categories defined and reported by the U.S. Census Bureau: S1100, primary roads; S1200, secondary roads; and

S1400, local and rural roads and city streets. The Bureaus sought comment on this proposal and provided data on nine categories—the proposed three categories and six more categories. Several commenters asked us to include additional road categories. Specifically, parties requested the addition of road categories S1500, 4WD vehicular trails; S1640, service drives; and S1740, private roads for service vehicles. Based on these comments and an analysis of 2010 census blocks and TIGER road mile data, the Bureaus decide to include these additional road categories. These categories will add three types of roads that are particularly important in some rural areas: unpaved dirt trails where a four-wheel drive vehicle is required, service drives that typically connect to highways and other types of roads, and private roads that are used in areas with logging, mining, oil fields, and ranches. Adding these categories provides a better representation of roads where people live, work, and travel since it means that, in every state and territory, the Bureaus are making support possible for 98 percent or more of the total road miles in eligible blocks. Furthermore, adding these three categories includes more unserved road miles in almost all states and, comparing the road miles in the selected categories to the road miles for all nine categories, increases the parity among the states of the proportion of unserved road miles that are included.

25. The list of census blocks released with the *Auction 901 Procedures Public Notice* includes, for each block, the number of road miles in each of the six selected road categories.

iv. Public Interest Obligations

26. *Voice and Broadband Service.* All Mobility Fund Phase I recipients must satisfy specified public interest obligations in exchange for the support they receive, as must all recipients of any Connect America Fund (CAF) support for fixed locations. Specifically, all CAF recipients, including Mobility Fund Phase I recipients, must offer stand-alone voice service to the public. Mobility Fund Phase I recipients must offer voice service with coverage of at least 75 percent or more of the designated road miles within the area for which support is provided. Furthermore, receipt of Mobility Fund Phase I support is conditioned upon the recipient providing service over a network that achieves particular data rates under particular conditions, which the Commission, for this purpose, refers to as third generation (3G) networks or better.

27. *Data Rates.* To provide specificity, and solely for purposes of Mobility Fund Phase I, the Commission refers to a network as a 3G network if it achieves outdoor minimum data transmission rates of 50 kilobits per second (kbps) uplink and 200 kbps downlink at vehicle speeds appropriate for the roads covered. Also solely for purposes of Mobility Fund Phase I, the Commission refers to a network as a fourth generation (4G) network if it achieves outdoor minimum data transmissions rates of 200 kbps uplink and 768 kbps downlink at vehicle speeds appropriate for the roads covered. With respect to both 3G and 4G networks, transmission latency must be low enough to enable the use of real-time applications, such as Voice over Internet Protocol (VoIP).

28. *Performance Deadlines.* Winning bidders in Auction 901 will commit to provide service over either a 3G or a 4G network, as those terms are used with respect to Mobility Fund Phase I, in their post-auction long-form applications for support. Those parties committing to provide service over a 3G network must do so for at least 75 percent or more of the designated road miles within the relevant area within two (2) years of being authorized to receive support. Winning bidders committing to provide service over a 4G network must do so for at least 75 percent or more of the designated road miles within the relevant area within three (3) years of being authorized to receive support. To the extent that a recipient covers road miles in excess of the minimum, support will be available for up to 100 percent of the designated road miles for which the recipient demonstrates coverage within the required timeframe associated with the technology deployed.

29. *Reasonably Comparable Rates.* Recipients of Mobility Fund Phase I support must certify annually that they offer service in areas with support at rates that are within a reasonable range of rates for similar service plans offered by mobile wireless providers in urban areas. This requirement extends for a period ending five years after the date of award of support.

30. *Collocation.* In exchange for the support provided, Mobility Fund Phase I recipients shall allow for reasonable collocation by other providers of services that would meet the voice and data requirements of Mobility Fund Phase I on newly constructed towers that the recipient owns or manages in the area for which it receives support. Consistent with this requirement, a recipient may not enter into facilities access arrangements regarding relevant facilities that restrict any party to the arrangement from allowing others to collocate on the facilities.

31. *Voice and Data Roaming.* Recipients of Mobility Fund Phase I support must provide voice and data roaming on networks built with the support, consistent with the requirements of 47 CFR 20.12 as those rules were in effect on the date the Commission adopted the *USF/ICC Transformation Order.* This condition of support is independent of subsequent changes to the Commission's rules on voice and data roaming, though to the extent any new rules are generally applicable, recipients of Mobility Fund Phase I support may be subject to those as well. As these requirements, as well as all the public interest obligations, are a condition of Mobility Fund Phase I support, violations may result in the withholding or clawing back of universal service support in addition to any other applicable sanctions.

v. Mobility Fund Phase I Eligibility Requirements

32. In order to participate in Auction 901 and receive Mobility Fund Phase I support, an applicant must demonstrate, for the areas on which it wishes to bid, that it has been designated as an eligible telecommunications carrier (ETC) and has access to the spectrum necessary to satisfy the applicable performance requirements. In addition, an applicant must certify that it is financially and technically capable of providing 3G or better service.

33. One commenter advocates restricting eligibility to participate in the auction based on additional factors, primarily related to the size of the applicant. The Commission previously considered and rejected similar proposals in the *USF/ICC Transformation Order.* The Commission concluded that the competitive bidding rules and the procedures to be developed by the Bureaus would promote its objectives for the Mobility Fund and provide a fair opportunity for serious, interested parties to participate. The Bureaus cannot modify the eligibility requirements because the changes the commenter advocates are beyond the scope of the Bureaus' delegated authority and the scope of this proceeding and would require action by the Commission to reconsider its determination in the *USF/ICC Transformation Order.*

34. On a related note, in connection with the *USF/ICC Transformation Order,* the Commission prepared a Final Regulatory Flexibility Analysis concerning the possible impact on small entities of, among other things, the Mobility Fund Phase I rules, as

implemented by the Bureaus in the *Auction 901 Procedures Public Notice.*

vi. Annual Reporting and Record Retention Requirements

35. Winning bidders that are authorized to receive Mobility Fund Phase I support are required to submit to the Commission an annual report each year for the five years after being so authorized. The information and certifications required to be included in the annual report are described in 47 CFR 54.1009. In addition, authorized winning bidders are required to submit certain reports before receiving disbursements of support. Mobility Fund Phase I support will be available for disbursement to authorized winning bidders in three stages, with the first disbursement made when the winning bidder is authorized to receive support. A recipient will be eligible to receive the second disbursement when it submits a report demonstrating coverage of 50 percent of the applicable coverage requirements of 47 CFR 54.1006. A recipient will be eligible to receive the final disbursement when it submits a report demonstrating coverage meeting the applicable requirements of 47 CFR 54.1006.

36. A winning bidder authorized to receive Mobility Fund Phase I support and all of its agents are required to retain any documentation prepared for, or in connection with, the award of Mobility Fund Phase I support for a period of not less than ten years after the date on which the winning bidder receives its final disbursement of Mobility Fund Phase I support.

C. Auction Specifics

i. Auction Start Date

37. Bidding in Auction 901 will be held on Thursday, September 27, 2012. Two commenters contend that the auction should be delayed in light of pending litigation regarding the source of funds to be disbursed based on the auction and in light of pending petitions for reconsideration of various aspects of the *USF/ICC Transformation Order.* Neither pending litigation nor the pending petitions are a sufficient basis for the Bureaus to delay the scheduled auction start date. The Commission already has considered the issues in the pending litigation at length in proceedings before it, and no action taken in the *Auction 901 Procedures Public Notice* would prejudge the Commission's review of the petitions seeking reconsideration of the *USF/ICC Transformation Order.*

38. The start and finish time of bidding in Auction 901 will be announced by public notice approximately one week before the start of the auction. Unless otherwise announced, bidding for all census blocks will be offered at the same time.

ii. Bidding Methodology

39. The bidding methodology for Auction 901 will be single-round reverse format. The Commission will conduct this auction over the Internet using the FCC Auction System. Qualified bidders are permitted to bid electronically via the Internet. Telephonic bidding will not be available for Auction 901 because it will not be feasible given the number of eligible geographic areas and the manner in which bids will be uploaded.

iii. Pre-Auction Dates and Deadlines

40. The following dates and deadlines apply to Auction 901: (1) An auction tutorial will available (via Internet) by June 27, 2012; (2) short-form application (FCC Form 180) filing window opens on June 27, 2012, at 12 noon ET; (3) short-form application (FCC Form 180) filing window closes on July 11, 2012, at 6:00 p.m. ET; (4) a mock auction will be held on September 25, 2012; and (5) Auction 901 will be held on September 27, 2012.

iv. Requirements for Participation

41. Those wishing to participate in this auction must: (1) submit a short-form application (FCC Form 180) electronically prior to 6 p.m. ET on July 11, 2012, following the electronic filing procedures that will be provided in a future public notice; and (2) comply with all provisions outlined in the *Auction 901 Procedures Public Notice* and applicable Commission rules.

D. Rules and Disclaimers

i. Relevant Authority

42. Prospective applicants in Auction 901 must familiarize themselves with the Commission's general universal service rules, contained in 47 CFR part 54, and the Mobility Fund specifically, 47 CFR 54.1001- 54.1010. They should also familiarize themselves with the Commission's decision in the *USF/ICC Transformation Order* to implement the Mobility Fund Phase I. Prospective bidders in Auction 901 must be familiar with the specific competitive bidding rules for universal service support contained in 47 CFR 1.21000—1.21004, as well as the procedures, terms and conditions contained in the *Auction 901 Procedures Public Notice,* the *Auction 901 Comment Public Notice,* and all other public notices related to Auction 901 (AU Docket No. 12–25). Additionally, prospective Auction 901 bidders will find it helpful to familiarize themselves with the Commission's general competitive bidding rules, including recent amendments and clarifications, as well as Commission decisions in proceedings regarding competitive bidding procedures, application requirements, and obligations of Commission licensees.

43. The terms contained in the Commission's rules, relevant orders, and public notices are not negotiable. The Commission may amend or supplement the information contained in its public notices at any time, and will issue public notices to convey any new or supplemental information to applicants. It is the responsibility of all applicants to remain current with all Commission rules and with all public notices pertaining to this auction.

ii. Prohibited Communications and Compliance With Antitrust Laws

44. To ensure the competitiveness of the auction process, 47 CFR 1.21002 prohibits an applicant in a Mobility Fund auction from cooperating or collaborating with any other applicant with respect to its own, or one another's, or any other competing applicant's bids or bidding strategies, and from communicating with any other applicant in any manner the substance of its own, or one another's, or any other competing applicant's bids or bidding strategies, until after the post-auction deadline for winning bidders to submit applications for support, unless such applicants are members of a joint bidding arrangement identified on the short form application(s) pursuant to 47 CFR 1.21001(b)(3)–(4).

45. 47 CFR 1.21002 is based on a similar rule used by the Commission in competitive bidding for spectrum licenses, 47 CFR 1.2105(c). Potential bidders should familiarize themselves with 47 CFR 1.2105(c) and 1.21002, as well as the judicial, Commission and Wireless Bureau decisions addressing application of the rule prohibiting certain communications listed in Attachment E of the *Auctions 901 Procedures Public Notice.* The Bureaus encourage applicants to review information regarding the Commission's interpretation of 47 CFR 1.2105(c) to gain insight into its views on prohibited communications during competitive bidding for Mobility Fund support.

a. Entities Subject to Section 1.21002, the Rule on Prohibited Communications

46. The prohibition on certain communications contained in 47 CFR 1.21002 will apply to any applicant that submits a short-form application to participate in Auction 901. Thus, unless they have identified each other on their

short-form applications as parties with whom they have entered into agreements under 47 CFR 1.21001(b)(3), applicants in Auction 901 must affirmatively avoid all communications with or disclosures to each other that affect or have the potential to affect bids or bidding strategy. In some instances, this prohibition extends to communications regarding the post-auction market structure. This prohibition applies to all applicants regardless of whether such applicants become qualified bidders or actually bid.

47. For the Mobility Fund Phase I auction, all bidders will compete for support with all other bidders in Auction 901, regardless of the geographic areas they seek to serve with Mobility Fund support. Therefore, applicants will be prohibited from making certain communications with all other applicants in Auction 901 regardless of the geographic areas they select, unless the parties disclose agreements reached between the parties on their short-form applications.

48. For purposes of the prohibition on certain communications, 47 CFR 1.21002 defines *applicant* broadly to include the applicant, each party capable of controlling the applicant, including all officers and directors, and each party that may be controlled by the applicant or by a party capable of controlling the applicant.

49. Individuals and entities subject to 47 CFR 1.21002 should take special care in circumstances where their officers, directors and employees may receive information directly or indirectly relating to any competing applicant's bids or bidding strategies.

50. Moreover, Auction 901 applicants are encouraged not to use the same individual as an authorized bidder. A violation of 47 CFR 1.21002 could occur if an individual acts as the authorized bidder for two or more competing applicants, and conveys information concerning the substance of bids or bidding strategies between such applicants. Also, if the authorized bidders are different individuals employed by the same organization (e.g., a law firm or engineering firm or consulting firm), a violation similarly could occur. In such a case, at a minimum, applicants should certify on their applications that precautionary steps have been taken to prevent communication between authorized bidders, and that the applicant and its bidders will comply with 47 CFR 1.21002.

b. Prohibition Applies Until Long Form Application Deadline

51. 47 CFR 1.21002 prohibition on certain communications begins at the short-form application filing deadline and ends at the long form application deadline after the auction closes, which will be announced in a future public notice.

c. Prohibited Communications

52. Applicants must not communicate directly or indirectly about bids or bidding strategy to other applicants. 47 CFR 1.21002 prohibits not only communication about an applicant's own bids or bidding strategy, it also prohibits communication of another applicant's bids or bidding strategy. While the rule does not prohibit non-auction-related business negotiations among auction applicants, each applicant must remain vigilant so as not to directly or indirectly communicate information that affects, or could affect, bids, bidding strategy, or the negotiation of settlement agreements.

53. Applicants are cautioned that the Commission remains vigilant about prohibited communications taking place outside of the auction itself. The Commission has warned that prohibited communications concerning bids and bidding strategies may include communications regarding capital calls or requests for additional funds in support of bids or bidding strategies to the extent such communications convey information concerning the bids and bidding strategies directly or indirectly. Moreover, the Commission has found a violation of the rule against prohibited communications where an applicant used the Commission's bidding system to disclose its bidding strategy in a manner that explicitly invited other auction participants to cooperate and collaborate in specific markets, and has placed auction participants on notice that the use of its bidding system to disclose market information to competitors will not be tolerated and will subject bidders to sanctions. Applicants also should use caution in their dealings with other parties, such as members of the press, financial analysts, or others who might become conduits for the communication of prohibited bidding information. For example, an applicant's statement to the press that it intends to stop bidding in the auction could give rise to a finding of 47 CFR 1.21002 violation. Similarly, an applicant's public statement of intent not to participate in Auction 901 bidding could also violate the rule. Applicants are hereby placed on notice that public disclosure of information relating to bids, or bidding strategies, or to post auction market structures may violate 47 CFR 1.21002.

d. Disclosure of Bidding Agreements and Arrangements

54. The Commission's rules do not prohibit applicants from entering into otherwise lawful bidding agreements before filing their short-form applications, as long as they disclose the existence of the agreement(s) in their short-form applications. Applicants must identify in their short-form applications all parties with whom they have entered into any agreements, arrangements, or understandings of any kind relating to the Mobility Fund Phase I support they seek, including any agreements relating to post-auction market structure.

55. If parties agree in principle on all material terms prior to the short-form application filing deadline, each party to the agreement must identify the other party or parties to the agreement on its short-form application under 47 CFR 1.21001(b)(3), even if the agreement has not been reduced to writing. If the parties have not agreed in principle by the short-form filing deadline, they should not include the names of parties to discussions on their applications, and they may not continue negotiation, discussion or communication with any other applicants after the short-form application filing deadline.

56. 47 CFR 1.21002 does not prohibit non-auction-related business negotiations among auction applicants. However, certain discussions or exchanges could touch upon impermissible subject matters because they may convey pricing information and bidding strategies. Such subject areas include, but are not limited to, issues such as management, sales, local marketing agreements, and other transactional agreements.

e. Section 1.21001(b)(4)–(5) Applicant Certifications

57. By electronically submitting a short-form application, each applicant in Auction 901 certifies its compliance with 47 CFR 1.21001(b)(3) and 1.21002. In particular, an applicant must certify under penalty of perjury that the application discloses all real parties in interest to any agreements involving the applicant's participation in the competitive bidding for Mobility Fund support. Also, the applicant must certify that it and all applicable parties have complied with and will continue to comply with 47 CFR 1.21002.

58. The Bureaus caution, however, that merely filing a certifying statement as part of an application will not

outweigh specific evidence that a prohibited communication has occurred, nor will it preclude the initiation of an investigation when warranted. The Commission has stated that it intends to scrutinize carefully any instances in which bidding patterns suggest that collusion may be occurring. Any applicant found to have violated 47 CFR 1.21001(b)(4) and (5) may be subject to sanctions.

f. Duty To Report Prohibited Communications

59. 47 CFR 1.21002(c) provides that any applicant that makes or receives a communication that appears to violate 47 CFR 1.21002 must report such communication in writing to the Commission immediately, and in no case later than five business days after the communication occurs. An applicant's obligation to make such a report continues until the report has been made.

60. In addition, 47 CFR 1.65 requires an applicant to maintain the accuracy and completeness of information furnished in its pending application and to notify the Commission of any substantial change that may be of decisional significance to that application. Thus, the rule requires an Auction 901 applicant to notify the Commission of any substantial change to the information or certifications included in its pending short-form application. An applicant is therefore required by 47 CFR 1.65 to report to the Commission any communication the applicant has made to or received from another applicant after the short-form application filing deadline that affects or has the potential to affect bids or bidding strategy, unless such communication is made to or received from a party to an agreement identified under 47 CFR 1.21001(b)(4).

61. 47 CFR 1.65(a) and 1.21002 require each applicant in competitive bidding proceedings to furnish additional or corrected information within five days of a significant occurrence, or to amend its short-form application no more than five days after the applicant becomes aware of the need for amendment. These rules are intended to facilitate the auction process by making the information available promptly to all participants and to enable the Bureaus to act expeditiously on those changes when such action is necessary.

g. Procedure for Reporting Prohibited Communications

62. A party reporting any prohibited communication pursuant to 47 CFR 1.65, 1.21001(b), or 1.21002(c) must take care to ensure that any report of the prohibited communication does not itself give rise to a violation of 47 CFR 1.21002. For example, a party's report of a prohibited communication could violate the rule by communicating prohibited information to other applicants through the use of Commission filing procedures that would allow such materials to be made available for public inspection.

63. Parties must file only a single report concerning a prohibited communication and must file that report with Commission personnel expressly charged with administering the Commission's auctions. This rule is designed to minimize the risk of inadvertent dissemination of information in such reports. Any reports required by 47 CFR 1.21002(c) must be filed consistent with the instructions set forth in the *Auction 901 Procedures Public Notice.* For Auction 901, such reports must be filed with the Chief of the Auctions and Spectrum Access Division, Wireless Telecommunications Bureau, by the most expeditious means available. Any such report should be submitted by email to the following email address: *auction901@fcc.gov.* If you choose instead to submit a report in hard copy, any such report must be delivered only to: Margaret W. Wiener, Chief, Auctions and Spectrum Access Division, Wireless Telecommunications Bureau, Federal Communications Commission, 445 12th Street SW., Room 6423, Washington, DC 20554.

64. A party seeking to report such a prohibited communication should consider submitting its report with a request that the report or portions of the submission be withheld from public inspection by following the procedures specified in 47 CFR 0.459. The Bureaus encourage such parties to coordinate with the Auctions and Spectrum Access Division staff about the procedures for submitting such reports.

h. Winning Bidders May Need To Disclose Terms of Agreements

65. Each applicant that is a winning bidder may be required to disclose in its long-form application the specific terms, conditions, and parties involved in any agreement it has entered into. This may apply to any bidding consortia, joint venture, partnership, or agreement, understanding, or other arrangement entered into relating to the competitive bidding process, including any agreement relating to the post-auction market structure. Failure to comply with the Commission's rules can result in enforcement action.

i. Antitrust Laws

66. The Bureaus also remind applicants that, regardless of compliance with the Commission's rules, they remain subject to the antitrust laws, which are designed to prevent anticompetitive behavior in the marketplace. Compliance with the disclosure requirements of 47 CFR 1.21002 will not insulate a party from enforcement of the antitrust laws. For instance, a violation of the antitrust laws could arise out of actions taking place well before any party submitted a short-form application. Similarly, the Wireless Bureau previously reminded potential applicants and others that even where the applicant discloses parties with whom it has reached an agreement on the short-form application, thereby permitting discussions with those parties, the applicant is nevertheless subject to existing antitrust laws.

67. To the extent the Commission becomes aware of specific allegations that suggest that violations of the federal antitrust laws may have occurred, the Commission may refer such allegations to the United States Department of Justice for investigation. If an applicant is found to have violated the antitrust laws or the Commission's rules in connection with its participation in the competitive bidding process, it may be subject to a forfeiture and may be prohibited from participating in future auctions, among other sanctions.

iii. Due Diligence

68. The Bureaus remind each potential bidder that it has sole responsibility for investigating and evaluating all technical and marketplace factors that may have a bearing on the level of Mobility Fund Phase I support it submits as a bid in Auction 901. Each bidder is responsible for assuring that, if it wins the support, it will be able to build and operate facilities in accordance with the Mobility Fund obligations and the Commission's rules generally.

69. Applicants should be aware that Auction 901 represents an opportunity to apply for Mobility Fund support, subject to certain conditions and regulations. Auction 901 does not constitute an endorsement by the FCC of any particular service, technology, or product, nor does Mobility Fund support constitute a guarantee of business success.

70. An applicant should perform its due diligence research and analysis before proceeding, as it would with any new business venture. In particular, the Bureaus strongly encourage each

potential bidder to review all underlying Commission orders, including the *USF/ICC Transformation Order.* Each potential bidder should perform technical analyses or refresh its previous analyses to assure itself that, should it become a winning bidder for Mobility Fund Phase I support, it will be able to build and operate facilities that will fully comply with all applicable technical and legal requirements. The Bureaus strongly encourage each applicant to inspect any prospective transmitter sites located in, or near, the service area for which it plans to construct transmitters with Mobility Fund support, to confirm the availability of such sites, and to familiarize itself with the Commission's rules regarding environmental compliance.

71. The Bureaus strongly encourage each applicant to conduct its own research prior to Auction 901 in order to determine the existence of pending administrative or judicial proceedings, including pending allocation rulemaking proceedings that might affect its decision to participate in the auction. The due diligence considerations mentioned in the *Auction 901 Procedures Public Notice* do not comprise an exhaustive list of steps that should be undertaken prior to participating in this auction. As always, the burden is on the potential bidder to determine how much research to undertake, depending upon specific facts and circumstances related to its interests.

72. The Bureaus also remind each applicant that pending and future judicial proceedings, as well as certain pending and future proceedings before the Commission—including applications, applications for modification, petitions for rulemaking, requests for special temporary authority, waiver requests, petitions to deny, petitions for reconsideration, informal objections, and applications for review—may relate to particular licensees or applicants for support in Auction 901. Each prospective applicant is responsible for assessing the likelihood of the various possible outcomes and for considering the potential impact on Mobility Fund Phase I support available through this auction.

73. Each applicant is solely responsible for identifying associated risks and for investigating and evaluating the degree to which such matters may affect its ability to bid on or otherwise receive Mobility Fund Phase I support. Each potential bidder is responsible for undertaking research to ensure that any support won in this auction will be suitable for its business plans and needs. Each potential bidder must undertake its own assessment of the relevance and importance of information gathered as part of its due diligence efforts.

74. The Commission makes no representations or guarantees regarding the accuracy or completeness of information in its databases or any third party databases, including, for example, court docketing systems. To the extent the Commission's databases may not include all information deemed necessary or desirable by an applicant, it must obtain or verify such information from independent sources or assume the risk of any incompleteness or inaccuracy in said databases. Furthermore, the Commission makes no representations or guarantees regarding the accuracy or completeness of information that has been provided by incumbent licensees and incorporated into its databases.

iv. Use of FCC Auction System

75. Bidders will be able to participate in Auction 901 over the Internet using the FCC Auction System. The Commission makes no warranty whatsoever with respect to the FCC Auction System. In no event shall the Commission, or any of its officers, employees, or agents, be liable for any damages whatsoever (including, but not limited to, loss of business profits, business interruption, loss of business information, or any other loss) arising out of or relating to the existence, furnishing, functioning, or use of the FCC Auction System that is accessible to qualified bidders in connection with this auction. Moreover, no obligation or liability will arise out of the Commission's technical, programming, or other advice or service provided in connection with the FCC Auction System.

v. Environmental Review Requirements

76. Recipients of Mobility Fund support, like all licensees, must comply with the Commission's rules regarding implementation of the National Environmental Policy Act and other federal environmental statutes. The construction of a wireless antenna facility is a federal action, and any entity constructing a wireless antenna facility must comply with the Commission's environmental rules for each such facility. The Commission's environmental rules require, among other things, that the entity constructing the facility consult with expert agencies having environmental responsibilities, including the U.S. Fish and Wildlife Service, the State Historic Preservation Office, the Army Corps of Engineers and the Federal Emergency Management Agency (through the local authority with jurisdiction over floodplains). In assessing the effect of facilities construction on historic properties, the entity constructing the facility must follow the provisions of the Nationwide Programmatic Agreement Regarding the Section 106 National Historic Preservation Act Review Process. The entity must prepare environmental assessments for facilities that may have a significant impact in or on wilderness areas, wildlife preserves, threatened or endangered species or designated critical habitats, historical or archaeological sites, Indian religious sites, floodplains, and surface features. The entity also must prepare environmental assessments for facilities that include high intensity white lights in residential neighborhoods or excessive radio frequency emission, or that are over 450 feet in height. Facilities that require antenna registration will also be required to complete an environmental notification process.

II. Short-Form Application Requirements

A. General Information Regarding Short-Form Applications

77. An application to participate in Auction 901, referred to as a short-form application or FCC Form 180, provides information used to determine whether the applicant is legally, technically, and financially qualified to participate in Commission auctions for universal service funding support. The short-form application is the first part of the Commission's two-phased auction application process. In the first phase, each party desiring to participate in the auction must file a streamlined, short-form application in which it certifies under penalty of perjury as to its qualifications. Each applicant must take seriously its duties and responsibilities and carefully determine before filing an application that it has the legal, technical and financial resources to participate in the auction and be able to meet the public interest obligations associated with Mobility Fund Phase I support. Eligibility to participate in bidding is based on the applicant's short-form application and certifications. In the second phase of the process, each winning bidder must file a more comprehensive long-form application (FCC Form 680).

78. Every entity seeking support available in Auction 901 must file a short-form application electronically via the FCC Auction System prior to 6 p.m.

ET on July 11, 2012. The short-form application requires each applicant to establish its eligibility for bidding for Mobility Fund Phase I support. Among other things, to establish eligibility at the short-form stage, an applicant must certify that it is a designated ETC in any geographic area for which it will seek support, or that it is a Tribally-owned or controlled entity with a pending application for ETC designation, and provide the Study Area Code(s) (SAC(s)) associated with its ETC designation and/or provide the name(s) of its corresponding Tribal land(s) in lieu of a SAC. Each applicant will also be required to provide a general narrative description of its access to the spectrum it plans to use to meet Mobility Fund obligations in the particular area(s) for which it plans to bid and certify that it will retain its access to the spectrum for at least five years from the date of award of support. If an applicant claims eligibility for a Tribal land bidding credit as a Tribally-owned or controlled entity, the information provided in its FCC Form 180 will be used in determining whether the applicant is eligible for the claimed bidding credit. Each applicant filing a short-form application is subject to the Commission's rule prohibiting certain communications beginning on the deadline for filing.

79. Each applicant bears full responsibility for submitting an accurate, complete, and timely short-form application. Each applicant must certify on its short-form application under penalty of perjury that it is legally, technically, financially and otherwise qualified to receive universal service support funding. Each applicant should consult the Commission's rules to ensure that all the information required is included in its short-form application.

80. A party may not submit more than one short-form application for Auction 901. If a party submits multiple short-form applications, only one application may be accepted for filing.

81. Each applicant also should note that submission of a short-form application (and any amendments thereto) constitutes a representation by the certifying official that he or she is an authorized representative of the applicant, that he or she has read the form's instructions and certifications, and that the contents of the application, its certifications, and any attachments are true and correct. An applicant is not permitted to make major modifications to its application; such impermissible changes include a change of the certifying official to the application. Submission of a false certification to the Commission may result in penalties, including monetary forfeitures, the forfeiture of universal service support, license forfeitures, ineligibility to participate in future auctions, and/or criminal prosecution.

B. SAC Identification

82. An applicant will not be required to select the specific census blocks on which it wishes to bid when submitting its short-form application. Based on the SAC(s) or Tribal land(s) information entered by an applicant, the FCC Auction System will identify eligible tracts and blocks in the associated state(s) or Tribal land(s) for each applicant during the application process.

C. Disclosure of Bidding Arrangements

83. An applicant will be required to identify in its short-form application all real parties-in-interest to any agreements relating to the participation of the applicant in the competitive bidding for Mobility Fund support.

84. Each applicant will also be required to certify under penalty of perjury in its short-form application that it has disclosed all real parties-in-interest to any agreements involving the applicant's participation in the competitive bidding for Mobility Fund support. If an applicant has had discussions, but has not reached an agreement by the short-form application filing deadline, it should not include the names of parties to the discussions on its application and may not continue such discussions with any applicants after the deadline.

85. Moreover, each applicant will also be required to certify under penalty of perjury in its short-form application that it and all applicable parties have complied with and will continue to comply with 47 CFR 1.21002. While 47 CFR 1.21002 does not prohibit non-auction-related business negotiations among auction applicants, the Bureaus remind applicants that certain discussions or exchanges could touch upon impermissible subject matters because they may convey pricing information and bidding strategies. Compliance with the disclosure requirements of 47 CFR 1.21002 will not insulate a party from enforcement of the antitrust laws.

D. Ownership Disclosure Requirements

86. Each applicant must comply with the uniform Part 1 ownership disclosure standards and provide information required by 47 CFR 54.1005(a)(1) and 1.2112(a). Specifically, in completing the short-form application, an applicant will be required to fully disclose information on the real party- or parties-in-interest and the ownership structure of the applicant, including both direct and indirect ownership interests of 10 percent or more, as prescribed in 47 CFR 1.2112(a). Each applicant is responsible for ensuring that information submitted in its short-form application is complete and accurate.

87. In certain circumstances, an applicant's most current ownership information on file with the Commission, if in an electronic format compatible with the short-form application (FCC Form 180) (such as information submitted in an FCC Form 602 or in an FCC Form 175 filed for a previous Commission spectrum license auction using the FCC Auction System), will automatically be entered into the applicant's short-form application. Each applicant must carefully review any information automatically entered to confirm that it is complete and accurate as of the deadline for filing the short-form application. Any information that needs to be corrected or updated must be changed directly in the short-form application.

E. Specific Mobility Fund Phase I Eligibility Requirements and Certifications

i. ETC Designation Certification

88. In the *USF/ICC Transformation Order,* the Commission concluded that, in order to apply to participate in an auction offering Mobility Fund support, any entity first had to be designated as an ETC pursuant to section 214 of the Communications Act in any geographic area for which it seeks support, with one narrow exception for Tribally-owned or controlled entities. An applicant must be the entity designated by a State or the Commission as an ETC in that geographic area. For example, if a designated ETC is a subsidiary of a parent holding company, only the subsidiary that is designated an ETC, and not the holding company, would be eligible to participate in the auction. For purposes of participation in the Mobility Fund, a party's ETC designation may not be limited in any way. Accordingly, a party designated as an ETC solely for purposes of the Low Income Program cannot satisfy the ETC eligibility requirement for the Mobility Fund on that basis. Of course, nothing prohibits such a party from seeking a general designation as an ETC and then, if it receives such a designation, participating in the Mobility Fund.

89. ETC status carries with it certain obligations. So that a party might obtain the required ETC designation but not be subject to those obligations unless and

until it wins any Mobility Fund support, the Commission further determined that a party might participate with an ETC designation conditioned upon the party winning support in the auction. At the short-form application stage, an applicant will be required to state that it is designated as an ETC in any area for which it will seek support, or is a Tribal entity with a pending application to become an ETC in any such area, and certify that the disclosure is accurate. A winning bidder will be required to provide proof of its ETC designation in all of the areas in which it will receive support before it may receive support.

90. *Pending ETC Designations.* The Commission further decided to permit participation by a Tribally-owned or controlled entity that at the short-form application deadline has an application for ETC designation pending for the provision of service within the boundaries of the associated Tribal land. The Commission did so to afford Tribes an increased opportunity to participate at auction, in recognition of their interest in self-government and self-provisioning on their own lands. A Tribally-owned or controlled entity whose application for ETC designation remains pending at the short-form application deadline is requested to provide the date the application was filed, with whom (i.e. the Commission or relevant state regulatory agency), any file or case number associated with the application, and its current status.

ii. Access to Spectrum Description and Certification

91. Pursuant to the *USF/ICC Transformation Order,* any applicant for Auction 901 must have access to the necessary spectrum to fulfill any obligations related to support. In an application to participate in Auction 901, each applicant must describe its required spectrum access and certify that the description is accurate and the applicant will retain such access for at least five (5) years from the date on which it is authorized to receive support. Specifically, an applicant will be required to disclose whether it currently holds or leases the spectrum and whether such spectrum access is contingent on obtaining support in Auction 901. For the described spectrum access to be sufficient as of the date of the short-form application, the applicant must obtain any necessary approvals from the Commission for the spectrum access prior to filing the application. A pending request for such an approval is not sufficient to satisfy this requirement. Furthermore, only assured access is sufficient, which means that the access must be to licensed spectrum subject to limited access. Accordingly, the applicant should identify the license applicable to the spectrum to be accessed, the licensee, and, if the licensee is a different party than the applicant, the relationship between the applicant and the licensee that provides the applicant with the required access. With the exception of the certification, the terms of which are set forth in FCC Form 180, an applicant must provide all required information relating to spectrum access in an attachment to FCC Form 180.

iii. Financial and Technical Capability Certification

92. The Commission requires that an applicant certify in the pre-auction short-form application that it is financially and technically capable of providing 3G or better service within the specified timeframe in the geographic areas for which it seeks support. This certification indicates that an applicant for Mobility Fund Phase I funds can provide the requisite service without any assurance of ongoing support for the areas in question after Mobility Fund Phase I support has been exhausted. An applicant should be aware that in making a certification to the Commission it exposes itself to liability for a false certification. An applicant should take care to review its resources and its plans before making the required certification and be prepared to document its review, if necessary.

iv. Certification That Applicant Will Not Seek Support for Areas in Which It Has Made a Public Commitment To Deploy 3G or Better Service by December 31, 2012

93. The Commission requires each applicant for Mobility Fund Phase I support to certify that the applicant will not seek support for any areas in which it has made a public commitment to deploy 3G or better wireless service by December 31, 2012. In determining whether an applicant has made such a public commitment, the Bureaus would consider any public statement made with some specificity as to both geographic area and time period as well as level of service. For example, in the public record generated in response to the *Auction 901 Comment Public Notice,* which sought comment on a list of census blocks potentially eligible for Mobility Fund Phase I support, more than one party publicly identified areas that they intend to cover with 3G or better service no later than December 31, 2012. This requirement helps to assure that Mobility Fund Phase I support will not go to finance coverage that carriers would have provided in the near term without any subsidy. Furthermore, the requirement may conserve funds and avoid displacing private investment by making a carrier that made such a commitment ineligible for Mobility Fund Phase I support with respect to the identified geographic area(s). Because circumstances are more likely to change over a longer term, the Bureaus do not hold providers to any statements for any time period beyond December 31, 2012. Applicants should note that this restriction does not prevent a party from seeking and receiving support for an eligible geographic area where another provider has announced such a commitment to deploy 3G or better.

F. Tribally-Owned or Controlled Providers—25 Percent Reverse Bidding Credit

94. The Commission adopted a 25 percent reverse bidding credit for Tribally-owned or controlled providers seeking either general or Tribal Mobility Fund Phase I support. In order to be eligible for the bidding credit, a qualifying Tribally-owned or controlled provider must certify in its short-form application that it is qualified and identify the applicable Tribe and Tribal lands.

95. The bidding credit will effectively reduce the Tribal entity's bid amount by 25 percent for the purpose of comparing it to other bids, thus increasing the likelihood that Tribally-owned and controlled entities will receive funding. If the Tribally-owned or controlled entity were to win, support would be calculated at the full, undiscounted bid amount. The preference is available with respect to the eligible census blocks located within the geographic area defined by the boundaries of the Tribal land associated with the Tribally-owned or controlled provider seeking support.

G. Commission Red Light Rules

96. Applications to participate in Auction 901 are subject to the Commission's rules regarding an applicant with delinquent debts, often referred to as the Commission Red Light Rules. Pursuant to these rules, unless otherwise expressly provided for, the Commission will withhold action on an application by any entity found to be delinquent in its debt to the Commission for purposes of the Red Light Rules. Accordingly, parties interested in filing applications to participate in Auction 901 should review the status of any debts that they owe the Commission before submitting their application and resolve any

delinquent debts. The Commission maintains a Red Light Display System (RLD) to enable entities doing business with the FCC to determine if they have any outstanding delinquent debt. The RLD enables a party to check the status of its account by individual FCC Registration Numbers (FRNs), and links other FRNs sharing the same Tax Identification Number (TIN) when determining whether there are outstanding delinquent debts. The RLD is available at *http://www.fcc.gov/redlight/.* Additional information is available at *http://transition.fcc.gov/debt_collection/.*

H. USF Debarment

97. The Commission's rules provide for the debarment of those convicted of or found civilly liable for defrauding the high-cost support program. Applicants are reminded that those rules apply with equal force to the Mobility Fund Phase I.

I. Minor Modifications to Short-Form Applications

98. After the deadline for filing initial applications, an Auction 901 applicant is permitted to make only minor changes to its application. Permissible minor changes include, among other things, deletion and addition of authorized bidders (to a maximum of three) and revision of the addresses and telephone numbers of the applicant and its contact person. An applicant is not permitted to make a major modification to its application (e.g., change in control of the applicant or change of the certifying official) after the initial application filing deadline. Thus, any change in control of an applicant, resulting from a merger, for example, will be considered a major modification, and the application will consequently be dismissed.

99. If an applicant wishes to make permissible minor changes to its short-form application, such changes should be made electronically to its short-form application using the FCC Auction System whenever possible. For the change to be submitted and considered by the Commission, be sure to click on the SUBMIT button. After the revised application has been submitted, a confirmation page will be displayed that states the submission time, submission date and a unique file number.

100. An applicant cannot use the FCC Auction System outside of the initial and resubmission filing windows to make changes to its short-form application other than administrative changes (e.g., changing certain contact information or the name of an authorized bidder). If these or other permissible minor changes need to be made outside of these windows, the applicant must submit a letter briefly summarizing the changes and subsequently update its short-form application in the FCC Auction System once it is available. Moreover, after the filing window has closed, the system will not permit applicants to make certain changes, such as the applicant's legal classification.

101. Any letter describing changes to an applicant's short-form application must be submitted by email to *auction901@fcc.gov.* The email summarizing the changes must include a subject or caption referring to Auction 901 and the name of the applicant, for example, ''RE: Changes to Auction 901 Short-Form Application of ABC Corp.'' Questions about short-form application amendments should be directed to the Auctions and Spectrum Access Division at (202) 418–0660.

102. Any application amendment and related statements of fact must be certified by an appropriate party. For example, one of the partners if the applicant is a partnership; or an officer, director, or duly authorized employee, if the applicant is a corporation; or a member who is an officer, if the applicant is an unincorporated association.

103. Applicants must not submit application-specific material through the Commission's Electronic Comment Filing System (ECFS), which was used for submitting comments regarding Auction 901. Parties submitting information related to their applications should use caution to ensure that their submissions do not contain confidential information or communicate information that would violate 47 CFR 1.21002 or the limited information procedures adopted for Auction 901. A party seeking to submit information that might reflect non-public information should consider submitting any such information along with a request that the filing or portions of the filing be withheld from public inspection until the end of the prohibition of certain communications pursuant to 47 CFR 1.21002.

J. Maintaining Current Information in Short-Form Applications

104. 47 CFR 1.65 requires an applicant to maintain the accuracy and completeness of information furnished in its pending application. If an amendment reporting changes is a major amendment, as defined by 47 CFR 1.21001(d)(4), the major amendment will not be accepted and may result in the dismissal of the application. After the application filing deadline, applicants may make only minor changes to their applications. For changes to be submitted and considered by the Commission, be sure to click on the SUBMIT button in the FCC Auction System. In addition, an applicant cannot update its short-form application using the FCC Auction System after the initial and resubmission filing windows close. If information needs to be submitted pursuant to 47 CFR 1.65 after these windows close, a letter briefly summarizing the changes must be submitted by email to *auction901@fcc.gov.* This email must include a subject or caption referring to Auction 901 and the name of the applicant. Applicants must not submit application-specific material through ECFS. A party seeking to submit information that might reflect non-public information should consider submitting any such information along with a request that the filing or portions of the filing be withheld from public inspection until the end of the prohibition of certain communications pursuant to 47 CFR 1.21002.

III. Pre-Auction Procedures

A. Online Auction Tutorial—Available June 27, 2012

105. No later than Wednesday, June 27, 2012, the Commission will post an educational auction tutorial on the Auction 901 web page for prospective bidders to familiarize themselves with the auction process. This online tutorial will provide information about pre-auction procedures, completing short-form applications, auction conduct, the FCC Auction System, auction rules, and Mobility Fund rules. The tutorial will also provide an avenue to ask FCC staff questions about the auction, auction procedures, filing requirements, and other matters related to this auction.

106. This interactive, online tutorial should provide an efficient and effective way for interested parties to further their understanding of the auction process. The Auction 901 online tutorial will allow viewers to navigate the presentation outline, review written notes, listen to audio of the notes, and search for topics using a text search function. Additional features of this web-based tool include links to auction-specific Commission releases, email links for contacting Commission licensing and auction staff, and a timeline with deadlines for auction preparation. The online tutorial will be accessible through a web browser with Adobe Flash Player. As always, Commission staff will be available to promptly answer questions posed by telephone and email throughout the

auction process. The auction tutorial will be accessible from the FCC's Auction 901 Web page at *http://wireless.fcc.gov/auctions/901/* through an Auction Tutorial link.

B. Short-Form Applications—Due Prior to 6 p.m. ET on July 11, 2012

107. In order to be eligible to bid in this auction, applicants must first follow the procedures to submit a short-form application (FCC Form 180) electronically via the FCC Auction System. This short-form application must be submitted prior to 6 p.m. ET on July 11, 2012. Late applications will not be accepted. No application fee is required.

108. Applications may generally be filed at any time beginning at noon ET on June 27, 2012, until the filing window closes at 6 p.m. ET on July 11, 2012. Applicants are strongly encouraged to file early and are responsible for allowing adequate time for filing their applications. Applications can be updated or amended multiple times until the filing deadline on July 11, 2012.

109. An applicant must always click on the SUBMIT button on the Certify & Submit screen to successfully submit its FCC Form 180 and any modifications; otherwise the application or changes to the application will not be received or reviewed by Commission staff. Additional information about accessing, completing, and viewing the FCC Form 180 will be provided in a future public notice. FCC Auctions Technical Support is available at (877) 480–3201, option nine; (202) 414–1250; or (202) 414–1255 (text telephone (TTY)); hours of service are Monday through Friday, from 8:00 a.m. to 6:00 p.m. ET. In order to provide better service to the public, all calls to Technical Support are recorded.

C. Application Processing and Minor Corrections

110. After the deadline for filing FCC Form 180 applications, Commission staff will process all timely submitted applications to determine which are complete, and subsequently will issue a public notice identifying (1) those that are complete; (2) those that are rejected; and (3) those that are incomplete or deficient because of minor defects that may be corrected. The public notice will include the deadline for resubmitting corrected applications.

111. After the application filing deadline on July 11, 2012, applicants can make only minor corrections to their applications. They will not be permitted to make major modifications (e.g., change control of the applicant or change of the certifying official).

112. Commission staff will communicate only with an applicant's contact person or certifying official, as designated on the short-form application, unless the applicant's certifying official or contact person notifies the Commission in writing that applicant's counsel or other representative is authorized to speak on its behalf. Authorizations may be sent by email to *auction901@fcc.gov.*

D. Auction Registration

113. Approximately ten days before the auction, the Bureaus will issue a public notice announcing all qualified bidders for the auction. Qualified bidders are those applicants with submitted FCC Form 180 applications that are deemed timely-filed, accurate, and complete.

114. All qualified bidders are automatically registered for the auction. Registration materials will be distributed prior to the auction by overnight mail. The mailing will be sent only to the contact person at the contact address listed in the FCC Form 180 and will include the SecurID® tokens that will be required to place bids, the FCC Auction System Bidder's Guide, and the Auction Bidder Line phone number.

115. Qualified bidders that do not receive this registration mailing will not be able to submit bids. Therefore, any qualified bidder that has not received this mailing by noon on Thursday, September 20, 2012, should call the Auctions Hotline at (717) 338–2868. Receipt of this registration mailing is critical to participating in the auction, and each applicant is responsible for ensuring it has received all of the registration material.

116. In the event that SecurID® tokens are lost or damaged, only a person who has been designated as an authorized bidder, the contact person, or the certifying official on the applicant's short-form application may request replacements. To request replacement of these items, call Technical Support at (877) 480–3201, option nine; (202) 414–1250; or (202) 414–1255 (TTY).

E. Remote Electronic Bidding

117. The Commission will conduct this auction over the Internet. Only qualified bidders are permitted to bid. Each authorized bidder must have its own SecurID® token, which the Commission will provide at no charge. Each applicant with one authorized bidder will be issued two SecurID® tokens, while applicants with two or three authorized bidders will be issued three tokens. A bidder cannot bid without their SecurID® tokens. For security purposes, the SecurID® tokens, a telephone number for bidding questions, and the FCC Auction System Bidder's Guide are only mailed to the contact person at the contact address listed on the FCC Form 180. Each SecurID® token is tailored to a specific auction. SecurID® tokens issued for other auctions or obtained from a source other than the FCC will not work for Auction 901.

118. Please note that the SecurID® tokens can be recycled and the Bureaus encourage bidders to return the tokens to the FCC. Pre-addressed envelopes will be provided to return the tokens once the auction has ended.

F. Mock Auction—September 25, 2012

119. All qualified bidders will be eligible to participate in a mock auction on Tuesday, September 25, 2012. The mock auction will enable qualified bidders to become familiar with the FCC Auction System and to practice submitting bids prior to the auction. The Bureaus strongly recommend that all qualified bidders participate to gain experience with the bidding procedures. Details will be announced in a future public notice.

IV. Auction Event

A. Auction Structure—Reverse Auction Mechanism

120. Auction 901 will be held on Thursday, September 27, 2012. The start and finish time of the bidding round will be announced in a public notice listing the qualified bidders, which will be released approximately 10 days before the start of the auction. The Bureaus choice of auction design for Auction 901 is specific to the particular context of the Mobility Fund Phase I auction. The choices made in the *Auction 901 Procedures Public Notice* do not prejudge future auction design choices for other phases of the Mobility Fund or other competitive bidding mechanisms related to the USF.

i. Single Round Sealed Bid Reverse Auction Format

121. The Bureaus will conduct Auction 901 using a single round of bidding. The Bureaus concluded in the *Auction 901 Procedures Public Notice* that a multiple round auction would not be appropriate in the context of the Mobility Fund Phase I, especially in light of the complications involved in conducting multiple rounds with many thousands of items. The Bureaus recognized that multiple round auctions can have important advantages, and in fact, the Commission generally uses a multiple round format for its spectrum license auctions. However, the Bureaus

did not believe that the circumstances favoring a multiple round auction—i.e., when there are strong interactions among items and when bidders are unsure as to the market value of the item—are significant enough here to outweigh concerns about the complexity it would add to the auction. As a result, the Bureaus will conduct Auction 901 using a single round of bidding.

ii. Aggregation Method—Predefined Aggregations

a. Census Blocks Aggregated to Census Tracts

122. Consistent with the framework laid out by the Commission in the *USF/ICC Transformation Order,* the Bureaus discussed in the *Auction 901 Comment Public Notice* several approaches to aggregating census blocks for bidding, noting that some aggregation of census blocks will be necessary because census blocks are on average far smaller than the average area covered by a single cell tower, which is likely to be the minimum incremental geographic area of expanded coverage. The *Auction 901 Comment Public Notice* proposed an approach that would give bidders the ability to create a limited number of package bids of blocks within a CMA—the bidder-defined option—and also described a predefined aggregation option whereby bidders would bid to cover the eligible blocks within census tracts. The record the Bureaus received in response to the *Auction 901 Comment Public Notice* was mixed.

123. Given the schedule for the Mobility Fund Phase I auction, the record received, and the amount of support being provided here, the Bureaus adopt a predefined aggregation approach, largely on considerations of speed and simplicity of implementation. Under that approach, all eligible census blocks will be grouped by the census tract in which they are located, and bidders will be able to bid for support for the eligible census blocks in a census tract, not on individual blocks. For each tract a bidder bids on, the bidder will indicate a per-unit price to cover the road miles in the eligible census blocks within that tract. The auction will assign support to awardees equal to the per-road mile rate of their bid multiplied by the number of road miles associated with the eligible census blocks within the tract as shown in the files provided by the Bureaus. Bidders may bid on multiple tracts and win support for any or all of them. Awardees will be required to cover a given percentage of the total eligible units in the tract—that is, a percentage of the total road miles that are in the eligible census blocks in the tract. Blocks in Alaska will not be aggregated for bidding, however, and bidders can place bids for support on individual census blocks in Alaska. The Bureaus also modify their tract aggregation approach for some tracts that include census blocks covering Tribal lands.

124. The Bureaus conclude that aggregating census blocks into tracts for bidding, except in Alaska, will provide a manageable bidding process, both for participants and the Commission, particularly in light of the speed with which the Bureaus want to proceed in distributing this one-time support. As noted in the *Auction 901 Updated Blocks Public Notice,* the Bureaus' list of potentially eligible census blocks includes over 460,000 blocks; bundled into tracts for bidding, there are approximately 6,100 tracts.

125. The predefined aggregation option that the Bureaus adopt does not permit package bidding—that is, it does not permit bidders to create their own groupings of census tracts on which to submit all-or-nothing bids. It does allow bidders to bid on as many individual tracts as they wish, and to win support for any or all of those tracts. The absence of explicit package bidding simplifies the process of determining which bids will be awarded support, relative to the proposed bidder-defined option (that allows bidders to create packages of census blocks), and consequently, may simplify the bidding process.

b. Exception, for Alaska, to Aggregation by Census Tract

126. The Bureaus will not aggregate eligible census blocks in Alaska into tracts for bidding, but will permit bidders to bid for support for individual census blocks. Bidders seeking support for eligible blocks in Alaska will indicate a per-unit price to cover the road miles in the eligible census block. The auction will assign support to awardees equal to the per-road mile rate of their bid multiplied by the number of road miles associated with the eligible census block, as shown in the files provided by the Bureaus. Bidders may bid on multiple blocks—including, if they wish, all the eligible census blocks in a tract, but they will have to bid on the blocks individually—and may win support for any or all of them.

127. In the *Auction 901 Comment Public Notice,* the Bureaus sought comment on this alternative approach for areas in Alaska under the suggested predefined aggregation option, which the Bureaus adopt here. In the *USF/ICC Transformation Order,* the Commission noted the large size of census blocks in Alaska, and in the *Auction 901 Comment Public Notice,* the Bureaus further pointed out that the average area of the Alaska census blocks on the preliminary list of eligible areas is approximately 40 square miles compared to an average area of approximately 1.1 square miles for blocks in the rest of the country. Given the extreme difference in average size of census areas in Alaska relative to those in the rest of the country, and because census blocks in Alaska may be closer in size to a minimum scale of buildout than are most blocks elsewhere, the Bureaus believe it will be helpful to give bidders the flexibility to bid on individual census blocks in Alaska.

128. The Bureaus do not make a more general size-based exception to the decision to conduct bidding on a census tract basis. Specifically, the *Auction 901 Comment Public Notice* asked whether, outside of Alaska, the Commission should use a geographic area other than tracts in areas where tracts exceed a certain size. The Bureaus received only limited response. An analysis of the census blocks in the list from the *Auction 901 Updated Blocks Public Notice* demonstrates that the average size of the blocks in Alaska are much larger than the average size of the blocks in other states. Based on the record (including the absence of any input on an appropriate size cutoff point at which the Bureaus would switch from bidding on a tract basis to bidding on a block basis), the Bureaus decline to extend their provisions for block-by-block bidding beyond Alaska.

c. Census Block Aggregation for Tracts With Tribal Lands

129. Another exception to aggregation by census tract will exist for some tracts that include census blocks covering Tribal lands. For tracts that contain some eligible blocks that are in a Tribal land and other eligible blocks that are not in a Tribal land, there will be separate aggregations of the Tribal blocks and the non-Tribal blocks. If the Tribal blocks in a tract are located in more than one Tribal area, there will be separate aggregations for each Tribal area.

d. Coverage Requirement

130. A winning bidder will be required to provide coverage to a minimum of 75 percent of the road miles associated with the eligible blocks in each tract for which it is awarded support within two years after its award of support is authorized for 3G deployments or three years for 4G deployments. If a winning bidder covers more than the minimum 75 percent of

qualifying road miles within the required timeframe, it may collect support for up to 100 percent of the qualifying road miles in each tract. This requirement is consistent with the coverage requirement associated with the predefined approach described in the *Auction 901 Comment Public Notice.*

iii. Winner Selection Process

131. Under the auction format that the Bureaus adopt, during the single bidding round, bidders will be able to submit bids that indicate a per-road mile support price at which they are willing to meet the Mobility Fund requirements to cover the qualifying road miles in a given tract. The qualifying road miles in a tract are the road miles in the selected road categories in the eligible census blocks in the tract.

132. After the single bidding round closes, in order to select winning bidders, the FCC Auction System will rank bids from lowest to highest per-road mile bid amount and assign support first to the bidder making the lowest per-road mile bid. For bidders claiming eligibility for a Tribal land bidding credit, the auction system will reduce the Tribal entity's bid amount by 25 percent for the purpose of comparing it to other bids, thus increasing the likelihood that Tribally-owned and controlled entities will receive funding. For all selected bids, an amount equal to the per-mile bid times the number of qualifying road miles in the area will be deducted from the total available funds. The auction system will continue to assign support to the next lowest per-unit bids in turn, as long as support has not already been assigned for that geographic area, deducting assigned support funds from the remaining available funds, and will continue until the sum of support funds of the winning bids is such that no further winning bids can be supported given the funds available. If there are any identical bids—in the same per-unit amounts to cover the same tract, submitted by different bidders—only one such bid, chosen randomly, will be considered in the ranking. A bidder will be eligible to receive support for each of its winning bids equal to the per-unit rate of a winning bid multiplied by the number of road miles in the eligible census blocks covered by the bid, subject to meeting the obligations associated with receiving support.

133. This method of identifying winning bidders will likely result in monies remaining in the fund after identifying the last lowest per-unit bid that does not exceed the funds available. When the auction reaches this point, the FCC Auction System will continue to consider bids in order of per-unit bid amount while skipping bids that would require more support than is available. In the unlikely event that the winner selection procedure arrives at a situation where there are two or more bids for the same per-unit amount but for different areas and remaining funds are insufficient to satisfy all of the tied bids, the auction system will award support to that combination of tied bids that will most nearly exhaust the available funds.

134. The Bureaus recognize that this approach may result in some unused funds when support awardees do not fully build out, but the Bureaus wish to encourage the extension of services as completely as possible within the tracts that are awarded support, and therefore the Bureaus must reserve funds sufficient to fully cover the supported tracts. The Bureaus anticipate that funds unused under Mobility Fund Phase I will be put to productive use under later stages of the Mobility Fund program or other USF reform efforts.

iv. Limited Information Disclosure Procedures: Information Available to Bidders Before and During the Auction

135. The Bureaus will conduct Auction 901 using procedures for limited information disclosure. That is, for Auction 901, the Bureaus will withhold, until after the close of bidding and announcement of auction results, the public release of (1) information from applicants' short-form applications regarding their interests in eligible census tracts and/or blocks in particular states and/or Tribal lands and (2) information that may reveal the identities of bidders placing bids and taking other bidding-related actions. Because the Bureaus will conduct Auction 901 using a single round of bidding, the Bureaus do not anticipate a need to release bidding-related actions during the auction as they would in a multiple round auction. If such circumstances arise prior to the release of non-public information and auction results, however, the Bureaus will not indicate the identity of any bidders taking such actions. After the close of bidding, information regarding applicants' interests in eligible geographic areas in particular state and/or Tribal lands, their bids, and any other bidding-related actions and information will be made publicly available.

v. Auction Delay, Suspension, or Cancellation

136. In the *Auction 901 Comment Public Notice,* the Bureaus proposed that, by public notice or by announcement during the auction, they may delay, suspend, or cancel the auction in the event of natural disaster, technical obstacle, administrative or weather necessity, evidence of an auction security breach or unlawful bidding activity, or for any other reason that affects the fair and efficient conduct of competitive bidding. The Bureaus received no comments on this issue.

137. Because this approach has proven effective in resolving exigent circumstances in previous auctions, the Bureaus adopt these proposals regarding auction delay, suspension, or cancellation. By public notice or by announcement during the auction, the Bureaus may delay, suspend, or cancel the auction in the event of natural disaster, technical obstacle, administrative or weather necessity, evidence of an auction security breach or unlawful bidding activity, or for any other reason that affects the fair and efficient conduct of competitive bidding. In such cases, the Bureaus, in their sole discretion, may elect to resume the auction starting from the point at which the auction was suspended, or cancel the auction in its entirety. Network interruption may cause the Bureaus to delay or suspend the auction. The Bureaus emphasize that they will exercise this authority solely at their discretion.

B. Bidding Procedures

i. Bidding

138. All bidding in Auction 901 will take place through the web-based FCC Auction System. To place bids, a bidder will upload a text file that includes, for each tract in the bid file, the tract number and the bid for the tract, expressed in dollars per road mile. For areas in Alaska, bids will include block numbers instead of tract numbers. When a bidder uploads a bid file, the FCC Auction System will provide a verification that includes the tract and/or block numbers, the dollars per road mile bid for each tract and/or block, the number of road miles in each tract and/or block, the total bid amount for each tract and/or block, and the county and state for each tract and/or block. The bidder then submits the bids, or the bidder can cancel the bids if it wishes to make changes.

139. Bidders must submit their bids before the finish time of the bidding round, which will be announced in a public notice listing the qualified bidders, which will be released approximately 10 days before the start of the auction.

ii. Reserve Prices

140. Under the Commission's rules on competitive bidding for high-cost universal service support adopted in the *USF/ICC Transformation Order,* the Bureaus have discretion to establish maximum acceptable per-unit bid amounts and reserve amounts, separate and apart from any maximum opening bids. As proposed, the Bureaus choose not to establish any maximum acceptable per-unit bid amounts or reserve prices. Although two commenters suggest that the Bureaus may want to consider some sort of reserve price, the Bureaus continue to believe that cross-area competition for support from a budget that is not likely to cover support for all of the areas receiving bids will constrain the bid amounts, and that a reserve price is not needed to guard against any unreasonably high winning bids.

iii. Bid Removal

141. For Auction 901, before the end of the single round of bidding, a bidder will have the option of removing any bid it has placed. By removing a selected bid(s), a bidder may effectively ''undo'' any of its bids placed within the single round of bidding. Once the single round of bidding ends, a bidder may no longer remove any of its bids.

142. To remove bids a bidder will upload a text file that includes the tract or block number for each bid it wants to remove. When a bidder uploads such a file, the FCC Auction System will provide a verification that includes the tract and/or block numbers, and the county and state for each tract and/or block.

iv. Auction Announcements

143. The Bureaus will use auction announcements to report necessary information. All auction announcements will be available by clicking a link in the FCC Auction System.

v. Auction Results

144. The Bureaus will determine the winning bids based on the lowest per-road mile bids. After the Bureaus announce the auction results, the Bureaus will provide downloadable files of the bidding and results data.

V. Post-Auction Procedures

A. General Information Regarding Long-Form Applications

145. For the Mobility Fund Phase I auction, the Commission adopted a two-phased auction application process. Pursuant to 47 CFR 54.1005(b), winning bidders for Mobility Fund Phase I support are required to file an application for support, referred to as a long-form application, no later than 10 business days after the public notice identifying them as winning bidders. Shortly after bidding has ended, the Commission will issue a public notice declaring the auction closed, identifying the winning bidders, and establishing the deadline for the long-form application. Winning bidders will use the new FCC Form 680 and the FCC Auction System to submit the long-form application. Details regarding the submission and processing of the long-form application will be provided in the public notice issued after the close of the auction.

146. In addition to the long-form application process, any bidder winning support for areas within Tribal lands must notify the relevant Tribal government no later than five business days after being identified by public notice as such a winning bidder. Information identifying the appropriate point of contact for the Tribal governments will be available through the Commission's Office of Native Affairs and Policy (ONAP), in coordination with the Wireless Bureau.

B. Long-Form Application: Disclosures and Certifications

147. Unless otherwise provided by public notice, within ten business days after release of the public notice announcing the close of Auction 901, a winning bidder must electronically submit a properly completed long-form application (FCC Form 680) for the areas for which it submitted winning bids. A Tribally-owned or controlled provider claiming eligibility for a Tribal land bidding credit must certify as to its eligibility for the bidding credit. Further filing instructions will be provided to winning bidders in the auction closing public notice.

i. Ownership Disclosure

148. In the *USF/ICC Transformation Order,* the Commission adopted for the Mobility Fund the existing Part 1 ownership disclosure requirements that already apply to short-form applicants to participate in spectrum license auctions and long-form applicants for licenses in wireless services. Under these requirements, an applicant for Mobility Fund support must fully disclose its ownership structure as well as information regarding the real party- or parties-in-interest of the applicant or application. To minimize the reporting burden on winning bidders, the Bureaus will allow them to use ownership information stored in existing Commission databases and update that information as necessary.

ii. Documentation of ETC Designation

149. A winning bidder is required to submit with its long-form application appropriate documentation of its ETC designation in all of the areas for which it will receive support and certify that its proof is accurate. Appropriate documentation should include the original designation order, any relevant modifications, e.g., expansion of service area or inclusion of wireless, along with any name-change orders. Any relevant information provided as an attachment to the long-form application must be designated as an Eligible Telecommunications Carrier attachment.

iii. Financial and Technical Capability Certification

150. As in the pre-auction short-form application stage, a long-form applicant must certify that it is financially and technically capable of providing 3G or better service within the specified timeframe in the geographic areas in which it seeks support. This certification indicates that an applicant for Mobility Fund Phase I funds can provide the requisite service without any assurance of ongoing support for the areas in question after Mobility Fund Phase I support has been exhausted. An applicant should be aware that in making a certification to the Commission it exposes itself to liability for a false certification. An applicant should take care to review its resources and its plans before making the required certification and be prepared to document its review, if necessary.

iv. Project Construction Schedule/ Specifications

151. Applicants are required to provide in their long-form application an attachment for each winning bid with a detailed project description which describes the network, identifies the proposed technology, demonstrates that the project is technically feasible, discloses the complete project budget and describes each specific phase of the project, e.g., network design, construction, deployment, and maintenance. A complete project schedule, including timelines, milestones and costs must be provided. Milestones should include the start and end date for network design; start and end date for drafting and posting requests for proposal (RFPs); start and end date for selecting vendors and negotiating contracts; start date for commencing construction and end date for completing construction; and the

dates by which it will meet applicable requirements to receive the installments of Mobility Fund support.

152. Applicants will indicate for each winning bid whether the supported network will provide 3G mobile service within the period prescribed by 47 CFR 54.1006(a) or 4G mobile service within the period prescribed by 47 CFR 54.1006(b). The description of the proposed technology should include information on whether the network will qualify as either a 3G or 4G network.

v. Spectrum Access

153. Applicants are required to provide a description of the spectrum access that the applicant will use to meet its obligations in areas for which it is the winning bidder, including whether the applicant currently holds a license for or leases the spectrum. The description should identify the license applicable to the spectrum to be accessed. The description of the license must include the type of service, e.g., AWS, 700 MHz, BRS, PCS, the particular frequency bands and the call sign. If the licensee is a different party than the applicant, the description should include the licensee name and the relationship between the applicant and the licensee that provides the applicant with the required access. If the applicant is leasing spectrum, the lease number should be provided along with the license information. An applicant must provide this required information relating to spectrum access in an attachment to the long-form application that is designated as a Spectrum Access attachment.

154. Applicants must also certify that the description of the spectrum access is accurate and that the applicant will retain such access for at least five (5) years after the date on which it is authorized to receive support. Applications will be reviewed to assess the reasonableness of the certification.

vi. Letter of Credit Commitment Letter

155. Within ten business days after release of the auction closing public notice, a winning bidder must submit with its long-form application either a Letter of Credit (LOC) for each winning bid or a written commitment letter from an acceptable bank to issue such an LOC. If the applicant submits a commitment letter, the letter will at a minimum provide the dollar amount of the LOC and the issuing bank's agreement to follow the terms and conditions of the Commission's model LOC, found in Appendix N of the *USF/ICC Transformation Order.* The commitment letter must be from an acceptable bank, as defined in 47 CFR 54.1007(a)(1).

vii. Letter of Credit and Bankruptcy Code Opinion Letter

156. After receipt and review of the long-form applications, the Commission will issue a public notice identifying each winning bidder that may be authorized to receive Mobility Fund Phase I support. Upon notice from the Commission, a winning bidder for Mobility Fund Phase I support must submit an irrevocable stand-by LOC, issued in substantially the same form as set forth in the model LOC provided in Appendix N of the *USF/ICC Transformation Order* by a bank that is acceptable to the Commission. An LOC must be submitted for each winning bid in an amount equal to one-third of the winning bid amount, plus an additional 10 percent of the winning bid amount which shall serve as a performance default payment. The Commission's rules provide specific requirements, as defined in 47 CFR 54.1007(a)(1), for a bank to be acceptable to the Commission to issue the LOC. Those requirements vary for United States banks and non-U.S. banks.

157. In addition, a winning bidder will be required to provide with the LOC an opinion letter from legal counsel clearly stating, subject only to customary assumptions, limitations and qualifications, that, in a proceeding under the Bankruptcy Code, the bankruptcy court would not treat the LOC or proceeds of the LOC as property of winning bidder's bankruptcy estate, or the bankruptcy estate of any other bidder-related entity requesting issuance of the LOC, under section 541 of the Bankruptcy Code.

viii. Certification as to Program Requirements

158. The long-form application contains certifications that the applicant has available funds for all project costs that exceed the amount of support to be received and will comply with all program requirements. The requirements include the public interest obligations contained in the Commission's rules. Applicants must certify that they will meet the applicable deadline for construction of a network meeting the coverage and performance requirements set forth in the rules, that they will comply with the Mobility Fund Phase I collocation obligations specified in the rules, and that they will comply with the voice and data roaming obligations the Commission has established with respect to Phase I of the Mobility Fund. With respect to demonstrating compliance with the coverage requirements, the Commission rules set forth the standards for applicable drive test data.

ix. Reasonably Comparable Rate Certification

159. To satisfy one of the public interest obligations that an applicant will have if it receives support, the long-form application also must contain a certification that the applicant will offer service in supported areas at rates that are within a reasonable range of rates for similar service plans offered by mobile wireless providers in urban areas for a period extending until five (5) years after the date on which it is authorized to receive support. As noted in the *Auction 901 Comment Public Notice,* the Commission delegated authority to the Bureaus to specify how support recipients could demonstrate compliance with this rate certification, in light of the fact that the voice and broadband rates survey data the Commission will collect pursuant to the *USF/ICC Transformation Order* will not be available prior to the Mobility Fund Phase I auction. The approach adopted for Phase I of the Mobility Fund in no way prejudges the approach to be taken with respect to Phase II of the Mobility Fund or the CAF generally. The appropriate approach for purposes of later phases of the Mobility Fund or other components of the CAF will be determined after review of the record developed in response to the Further Notice of Proposed Rulemaking portion of the *USF/ICC Transformation Order.*

160. The Bureaus proposed in the *Auction 901 Comment Public Notice* that a Mobility Fund Phase I support recipient could demonstrate compliance with the required certification that its rates are reasonably comparable if each of its service plans in supported areas is substantially similar to a service plan offered by at least one mobile wireless service provider in an urban area and is offered for the same or a lower rate than the matching urban service plan. The Bureaus expressly noted that any provider that itself offers the same service plan for the same rate in a supported area and in an urban area would meet this requirement.

161. The Bureaus crafted this proposal in order to provide recipients with flexibility to tailor their offerings to consumer demand while complying with the rule. Solely for purposes of Phase I of the Mobility Fund, the proposal would treat any rate equal to or less than the highest rate for a matching service charged in an urban area as reasonably comparable to, i.e., within a reasonable range of rates for similar service in urban areas. Urban

areas are generally served by multiple and diverse providers offering a range of rates and service offerings in competition with one another. Consequently, even the highest rate might be considered as being within a reasonable range of rates for similar service in urban areas, because the rates for the matching urban services reflect the effects of competition in the urban area. For purposes of this requirement, the Bureaus proposed defining urban area as one of the 100 most populated CMAs in the United States. Multiple providers currently serve these areas—99.2 percent of the population in these markets is covered by between four to six operators—offering a range of different service plans at prices generally constrained by the numerous providers. Finally, the Bureaus further proposed that they would retain discretion to consider whether and how variable rate structures should be taken into account.

162. The Bureaus sought comment on all aspects of the proposal, and specifically sought comment on whether a support recipient should be required to make this comparison for all of its service plans, or just its required stand-alone voice plan and one other plan offering broadband, or a set of its plans adopted by a specified percentage of its customers. With respect to the rates for services to which supported services are to be compared, the Bureaus asked whether additional information was required to validate the assumption that an urban service rate reflects the effects of competition in the urban area—for example, whether an urban service used for matching should be required to have a certain number of subscribers or percentage of the relevant market in order to demonstrate its market acceptance. The Bureaus noted that detailed information about the number of subscribers at a particular rate might be difficult to obtain. The Bureaus further sought comment on whether parties should be required to make comparisons only to a subset of the most populated CMAs that are geographically closest to the supported area, such as the 30 or 50 of the top 100 CMAs that are closest to the supported service area. This might protect against regional economic variations distorting the range of prices useable for comparison. For example, such a restriction might cause providers to compare supported rates in Oklahoma to rates in Houston or Chicago rather than in New York City.

163. There was support among some commenters for the framework of the Bureaus' proposal. Most commenters that addressed this issue generally favored employing as simple a standard as possible for determining whether a supported provider offered rates reasonably comparable to those in urban areas. Some parties advocated allowing supported parties to satisfy the requirement based on their offering the same rate, either nationwide, statewide, or in non-supported areas. The Bureaus note that, to the extent a provider offers the same service at the same rate in an urban area, as the Bureaus define it for these purposes, these proposals are all consistent with the Bureaus' proposal. The commenters' proposals diverge from the Bureaus' in so far as a provider offers the same rate for the same service in an unsupported area but that unsupported area does not qualify as urban for purpose of this requirement. Two parties specifically object to the use of out-of-Alaska areas as points of comparison for service within Alaska. They both argue that, given the unique challenges of offering service anywhere in Alaska, parties offering service in supported areas in Alaska only should have to demonstrate that their rates are reasonably comparable with more urban areas of Alaska, even though those areas do not qualify as urban under the Bureaus' proposal.

164. The Bureaus decline generally to alter the proposal to permit comparisons with rates for services in areas that are not within the definition of urban that the Bureaus proposed for this purpose in the *Auction 901 Comment Public Notice.* As the Bureaus explained in the *Auction 901 Comment Public Notice,* the areas proposed both meet a population-based definition of urban and have a degree of competition among wireless service providers that should help to assure that the rates offered are reasonable. None of the parties advocating intrastate comparisons, or reliance on comparisons between the rates a supported carrier offers in supported areas and other areas, provides a basis for concluding that the other areas proposed have a comparable level of competition. Nevertheless, in light of the distinct character of Alaska and the related costs of providing service, the Bureaus will make an exception for supported parties in Alaska and allow them to demonstrate comparability by comparison with rates offered in the CMA for Anchorage, Alaska. In this regard, the Bureaus note that the Anchorage CMA has a population of over 250,000 and four wireless providers, which indicates that, while reflecting the particular challenges of offering service in Alaska, competition for customers there could act to keep rates for offered services reasonable.

165. One commenter expressly supported the proposed requirement that supported providers demonstrate that all of their service plans are offered at comparable rates while another argued that providing one such plan should be sufficient. On further review, the Bureaus conclude that it will be sufficient for a supported provider to demonstrate that its required stand-alone voice plan and one service plan that offers data services, presuming it offers such plans, satisfies the reasonably comparable rate requirement. The Bureaus conclude that customers should have available to them other rate plans should they so choose, so long as the provider satisfies the reasonably comparable rate requirement with respect to a stand-alone voice plan and one of any plans that offer data services. In addition, this will simplify the supported parties' compliance with the rule.

x. Tribal Engagement Requirements: Certification and Summary of Engagement Results

166. Beginning at the long-form application stage, and continuing throughout the term of support, Mobility Fund Phase I winning bidders are required to comply with the Tribal engagement obligations applicable to all ETCs. As the Commission discussed in the *USF/ICC Transformation Order,* these obligations are designed to ensure that Tribal governments have been formally and effectively engaged in the planning process and that the services to be provided will advance the goals established by the Tribal government. At a minimum, such discussions must include: (1) A needs assessment and deployment planning with a focus on Tribal community anchor institutions; (2) feasibility and sustainability planning; (3) marketing services in a culturally sensitive manner; (4) rights of way processes, land use permitting, facilities siting, environmental and cultural review processes; and (5) compliance with Tribal business and licensing requirements.

167. Specific procedures and further guidance regarding the Tribal engagement process are being developed by ONAP, in coordination with the Bureaus. Winning bidders are encouraged to initiate the engagement process as soon as possible. The Bureaus contemplate that, at a minimum, a long-form applicant would be required to include a certification and detailed description of its efforts to contact the relevant Tribal government(s) and initiate substantive discussions regarding the topics noted above. Any information provided as an

attachment to the long-form application must be designated as a Tribal Information attachment. Such certification and description must also be submitted to the appropriate Tribal government official concurrent with the filing of the long-form application. Thereafter, support recipients will be obligated to demonstrate their compliance with Tribal engagement requirements on an annual basis, and prior to any disbursement of support from the Universal Service Administrative Company (USAC). The Bureaus remind carriers that failure to satisfy the Tribal government engagement obligation could subject them to financial consequences, including potential reduction in support should they fail to fulfill their obligations.

C. Default Payment Requirements

168. In the *USF/ICC Transformation Order,* the Commission determined that it would impose two types of default payment obligations on winning bidders: A default payment owed by Mobility Fund winning bidders that default on their winning bids prior to approval for receiving support and a default payment owed by Mobility Fund winning bidders that apply for and are approved to receive support but subsequently fail to meet their public interest obligations or other terms and conditions of Mobility Fund support. Under the competitive bidding rules adopted in the *USF/ICC Transformation Order,* bidders selected by the auction process to receive USF support have a binding obligation to file a post-auction long-form application—by the applicable deadline and consistent with other requirements of the long-form application process—and failure to do so constitutes an auction default. In addition, a performance default occurs when a winning bidder that the Commission has authorized to receive support fails to meet its minimum coverage requirement or adequately comply with quality of service or any other requirements upon which support was granted.

i. Auction Default Payment

169. Any winning bidder that fails to timely file a long-form application, is found ineligible or unqualified to receive Mobility Fund support, has its long-form application dismissed, or otherwise defaults on its bid or is disqualified for any reason after the close of the auction and prior to the authorization of support for each winning bid will be subject to an auction default payment. Agreeing to such payment in event of a default is a condition for participating in bidding. In the event of an auction default, the Bureaus will assess a default payment of five percent of the total defaulted bid.

170. In the *USF/ICC Transformation Order,* the Commission determined that a default payment is appropriate to ensure the integrity of the auction process and safeguard against costs to the Commission and the USF. The Commission left it to the Bureaus to consider methodologies for determining such a payment, but specified that if the Bureaus established a default payment to be calculated as a percentage of the defaulted bid, that percentage was not to exceed 20 percent of the total amount of the defaulted bid. Accordingly, in the *Auction 901 Comment Public Notice,* the Bureaus proposed an auction default payment of five percent of the total defaulted bid. The Bureaus also sought comment on alternative methodologies, such as basing the auction default payment on the difference between the defaulted bid and the next best bid to cover the same number of road miles as without the default. The Bureaus further sought comment on whether, prior to bidding, all applicants for Auction 901 should be required to furnish a bond or place funds on deposit with the Commission in the amount of the maximum anticipated auction default payment.

171. Commenters supported the Bureaus' proposal for a rate of five percent of the total defaulted bid. A commenter urges the Bureaus to consider adopting a higher figure, such as ten percent, saying that if the penalty percentage is too low it will not serve as a sufficient deterrent. Other commenters suggest a less punitive approach or ask the Bureaus to refrain from enforcing default payments except in cases of egregious failure, such as the failure to submit any long-form application. The Bureaus received no comments on any alternative methodologies for determining an appropriate auction default penalty.

172. The Bureaus are not persuaded that they should modify the proposal to establish an auction default payment at the rate of five percent of the total defaulted bid. Such a requirement should serve to deter failures to fulfill auction obligations that might undermine the stability and predictability of the auction process and impose costs on the Commission as well as higher support costs for USF, and is yet not unduly punitive. Liability for the auction default payment will be imposed without regard to the intentions or fault of any specific defaulting bidder. The Bureaus therefore adopt its proposal.

173. The Bureaus received a single comment addressing whether auction applicants should be required to furnish a bond or place funds on deposit prior to bidding. The Bureaus think their adoption of an auction default payment will provide adequate protection against costs to the Commission and the USF, and therefore the Bureaus find that establishing a bond or deposit requirement is unnecessary.

ii. Performance Default Payment

174. A winning bidder that has received notice from the Commission that it is authorized to receive Mobility Fund support will be subject to a performance default payment if it fails or is unable to meet its minimum coverage requirement, other service requirements, or fails to fulfill any other term or condition of Mobility Fund Phase I support. The Bureaus will assess a performance default penalty of ten percent on the total level of support for which a winning bidder is eligible.

175. The Commission recognized in the *USF/ICC Transformation Order* that a Mobility Fund recipient's failure to fulfill its obligations may impose significant costs on the Commission and higher support costs for the USF and concluded that it was necessary to adopt a default payment obligation for performance defaults. In addition to being liable for a performance default payment, the recipient will be required to repay the Mobility Fund all of the support it has received, and depending on circumstances, could be disqualified from receiving any additional Mobility Fund or other USF support. In the *Auction 901 Comment Public Notice,* the Bureaus proposed to establish the performance default payment percentage at ten percent of the total level of support for which a winning bidder is eligible. Under this proposal, the irrevocable stand-by LOC that winning bidders will be required to provide would include an additional ten percent based on the total level of support for which a winning bidder is eligible. The Bureaus received support for this proposal. While both auction defaults and performance defaults may threaten the integrity of the auction process and impose costs on the Commission and the USF, an auction default occurs earlier in the process and may facilitate an earlier use of the funds that were assigned to the defaulted bid consistent with the purposes of the universal service program. The Bureaus therefore proposed that the performance default payment be set at a higher percentage than the auction default payment percentage. The Bureaus did not receive specific comments on their

proposal to establish the performance default payment percentage at ten percent. The Bureaus anticipate that a performance default payment of ten percent of the defaulted support level will be effective in encouraging those seeking support to make every effort to assure that they are capable of meeting their obligations and protecting against costs to the Commission and the USF without unduly discouraging auction participation. The Bureaus therefore adopt this proposal.

Federal Communications Commission.

Gary Michaels,

Deputy Chief, Auctions and Spectrum Access Division, WTB.

[FR Doc. 2012–13223 Filed 5–30–12; 8:45 am]

BILLING CODE 6712–01–P

FEDERAL COMMUNICATIONS COMMISSION

Privacy Act System of Records

AGENCY: Federal Communications Commission.

ACTION: Notice; one new Privacy Act system of records.

SUMMARY: Pursuant to subsection (e)(4) of the Privacy Act of 1974, as amended (''Privacy Act''), 5 U.S.C. 552a, the FCC's Media Bureau (MB) proposes to add a new system of records, FCC/MB–2, ''Broadcast Station Public Inspection Files.'' The enactment of the Standardized and Enhanced Disclosure Requirements for Television Broadcast Licensee Public Interest Obligations and Extension of the Filing Requirement for Children's Television Programming Report (FCC Form 398), *Second Report and Order,* MM Docket 00–168, FCC 12–44, on April 27, 2012, adopted rules that require television broadcasters to submit their public filing information to the FCC to be posted in an on-line Broadcast Station Public Inspection File. The Commission's purpose for establishing this system of records, FCC/MB–2, ''Broadcast Station Public Inspection Files,'' is to cover the personally identifiable information (PII) that may be contained in the Broadcast Station Public Inspection Files.

DATES: In accordance with subsections (e)(4) and (e)(11) of the Privacy Act, any interested person may submit written comments concerning this new system of records on or before July 2, 2012. The Office of Information and Regulatory Affairs (OIRA), Office of Management and Budget (OMB), which has oversight responsibility under the Privacy Act to review the system of records, and Congress may submit comments on or before July 10, 2012. The proposed new system of records will become effective on July 10, 2012 unless the FCC receives comments that require a contrary determination. The Commission will publish a document in the **Federal Register** notifying the public if any changes are necessary. As required by 5 U.S.C. 552a(r) of the Privacy Act, the FCC is submitting reports on this proposed new system to OMB and Congress.

ADDRESSES: Address comments to Leslie F. Smith, Privacy Analyst, Performance Evaluation and Records Management (PERM), Room 1–C216, Federal Communications Commission (FCC), 445 12th Street SW., Washington, DC 20554, or via the Internet at *Leslie.Smith@fcc.gov<mailto:Leslie.Smith@fcc.gov>.*

FOR FURTHER INFORMATION CONTACT: Leslie F. Smith, Performance Evaluation and Records Management (PERM), Room 1–C216, Federal Communications Commission (FCC), 445 12th Street SW., Washington, DC 20554, (202) 418–0217, or via the Internet at *Leslie.Smith@fcc.gov<mailto:Leslie.Smith@fcc.gov>.*

SUPPLEMENTARY INFORMATION: As required by the *Privacy Act of 1974,* as amended, 5 U.S.C. 552a(e)(4) and (e)(11), this document sets forth notice of the proposed new system of records to be maintained by the FCC. This notice is a summary of the more detailed information about the proposed new system of records, which may be obtained or viewed pursuant to the contact and location information given above in the **ADDRESSES** section. The Commission's purpose for establishing this new system of records, FCC/MB–2, ''Broadcast Station Public Inspection Files,'' is to cover the personally identifiable information (PII) that may be contained in the Broadcast Station Public Inspection Files, which broadcasters are required to submit to the FCC to be posted in an on-line Broadcast Station Public Inspection File, as required by 47 CFR 73.3526 and 73.3527.

This notice meets the requirement documenting the proposed new system of records that is to be added to the systems of records that the FCC maintains, and provides the public, OMB, and Congress with an opportunity to comment.

FCC/MB–2

SYSTEM NAME:

Broadcast Station Public Inspection Files.

SECURITY CLASSIFICATION:

The FCC's Security Operations Center (SOC) has not assigned a security classification to this system of records.

SYSTEM LOCATION:

Media Bureau (MB), Federal Communications Commission (FCC), 445 12th Street SW., Washington, DC 20554.

CATEGORIES OF INDIVIDUALS COVERED BY THE SYSTEM:

The categories of individuals in this system include, but are not limited to:

1. Individuals who are required to file personal information pertaining to their political campaigns and other requirements; and

2. Individuals who are associated with a television broadcast station license and are required to submit information under 47 CFR 73.3526 and 73.3527.

CATEGORIES OF RECORDS IN THE SYSTEM:

The categories of records in this system may include, but are not limited to an individual's name, home address, home telephone number, personal cell phone number, personal email address(es), personal fax number, bank check routing number, credit card number, and other personal information (*i.e.,* personally identifiable information (PII)) that stations may include in their public files, and which may be included in the PII contained in the documents, files, and records that television broadcast stations and certain individuals are required to submit to the FCC to be posted in the FCC's on-line Broadcast Station Public Inspection Files. FCC Rules do not require submission of bank check routing numbers and credit card numbers, but the broadcast stations may choose to include such information in their public files as a means of indicating fulfillment of contracts.

AUTHORITY FOR MAINTENANCE OF THE SYSTEM:

47 U.S.C. 151, 152, 154(i), 303, 307, and 315.

PURPOSES:

The Commission will be hosting all Broadcast Station Public Inspection Files in an online database. Stations have been required to maintain their public files at their main studios for decades, pursuant to 47 CFR 73.3526 and 73.3527. The Commission will now begin hosting such files online in order to make the files more accessible to the public. Records in this system are available for public inspection.

ROUTINE USES OF RECORDS MAINTAINED IN THE SYSTEM, INCLUDING CATEGORIES OF USERS AND THE PURPOSES OF SUCH USES:

Information about individuals in this system of records may routinely be disclosed under the following conditions:

1. Public Access—Under the rules of the Commission, documents filed under the Consolidated Database System (CDBS) or in the online Broadcast Station Public Inspection Files are available for public inspection;

2. Public Access—Copies of FCC enforcement actions are available for public inspection via the Internet at <*http://www.fcc.gov/eb/*>, and in the FCC's Reference Information Center at <*http://www.fcc.gov/cgb/ric.html*>;

3. Law Enforcement and Investigation—Where there is an indication of a violation or potential violation of a statute, regulation, rule, or order, records from this system may be shared with appropriate Federal, State, or local authorities either for purposes of obtaining additional information relevant to a FCC decision or for referring the record for investigation, enforcement, or prosecution by another agency;

4. Adjudication and Litigation—Where by careful review, the Agency determines that the records are both relevant and necessary to litigation and the use of such records is deemed by the Agency to be for a purpose that is compatible with the purpose for which the Agency collected the records, these records may be used by a court or adjudicative body in a proceeding when: (a) The Agency or any component thereof; or (b) any employee of the Agency in his or her official capacity; or (c) any employee of the Agency in his or her individual capacity where the Agency has agreed to represent the employee; or (d) the United States Government is a party to litigation or has an interest in such litigation;

5. Department of Justice—A record from this system of records may be disclosed to the Department of Justice (DOJ) or in a proceeding before a court or adjudicative body when:

(a) The United States, the Commission, a component of the Commission, or, when represented by the government, an employee of the Commission is a party to litigation or anticipated litigation or has an interest in such litigation, and

(b) The Commission determines that the disclosure is relevant or necessary to the litigation;

6. Congressional Inquiries—When requested by a Congressional office in response to an inquiry by an individual made to the Congressional office for the individual's own records;

7. Government-wide Program Management and Oversight—When requested by the General Services Administration (GSA), the National Archives and Records Administration (NARA), and/or the Government Accountability Office (GAO) for the purpose of records management inspections conducted under authority of 44 U.S.C. 2904 and 2906 (such disclosure(s) shall not be used to make a determination about individuals); when the U.S. Department of Justice (DOJ) is contacted in order to obtain that department's advice regarding disclosure obligations under the Freedom of Information Act; or when the Office of Management and Budget (OMB) is contacted in order to obtain that office's advice regarding obligations under the Privacy Act;

8. Breach Notification—A record from this system may be disclosed to appropriate agencies, entities, and persons when: (1) The Commission suspects or has confirmed that the security or confidentiality of information in the system of records has been compromised; (2) the Commission has determined that as a result of the suspected or confirmed compromise there is a risk of harm to economic or property interests, identity theft or fraud, or harm to the security or integrity of this system or other systems or programs (whether maintained by the Commission or another agency or entity) that rely upon the compromised information; and (3) the disclosure made to such agencies, entities, and persons is reasonably necessary to assist in connection with the Commission's efforts to respond to the suspected or confirmed compromise and prevent, minimize, or remedy such harm;

9. FCC Enforcement Actions—When a record in this system involves a formal and/or informal complaint or inquiry filed alleging a violation of FCC Rules and Regulations by an applicant, licensee, certified or regulated entity or an unlicensed person or entity, the complaint may be provided to the alleged violator for a response. When an order or other Commission-issued document that includes consideration of a formal or informal complaint or complaints or inquiries is issued by the FCC to implement or to enforce FCC Rules and Regulations, the complainant's name or other PII may be made public in that order or document. Where a complainant in filing his or her complaint explicitly requests confidentiality of his or her name or other PII from public disclosure, the Commission will endeavor to protect such information from public disclosure. Complaints that contain requests for confidentiality may be dismissed if the Commission determines that the request impedes the Commission's ability to investigate and/or resolve the complaint;

10. Due Diligence Inquiries—Where there is an indication of a violation or potential violation of FCC Rules and Regulations (as defined above), records from this system may be shared with a requesting individual, or representative thereof, for purposes of obtaining such information so long as relevant to a pending transaction of a FCC-issued license; and

11. Financial Obligations under the Debt Collection Acts—A record from this system may be disclosed to other Federal agencies for the purpose of collecting and reporting on delinquent debts as authorized by the Debt Collection Act of 1982 or the Debt Collection Improvement Act of 1996. A record from this system may be disclosed to any Federal, state, or local agency to conduct an authorized computer matching program in compliance with the Privacy Act of 1974, as amended, to identify and locate individuals who are delinquent in their repayment of certain debts owed to the U.S. Government. A record from this system may be used to prepare information on items considered income for taxation purposes to be disclosed to Federal, state, and local governments.

In each of these cases, the FCC will determine whether disclosure of the records is compatible with the purpose(s) for which the records were collected.

DISCLOSURE TO CONSUMER REPORTING AGENCIES:

None.

POLICIES AND PRACTICES FOR STORING, RETRIEVING, ACCESSING, RETAINING, AND DISPOSING OF RECORDS IN THE SYSTEM:

STORAGE:

The information in the Broadcast Station Public Inspection Files includes electronic data, records, and files that are stored in the FCC's computer network databases.

RETRIEVABILITY:

Information in the Broadcast Station Public Inspection Files electronic databases can be retrieved by categories of information that each individual must provide as required by 47 CFR 73.3526 and 73.3527, including the individual's name(s), street address, email address(es), landline phone and cell phone number(s), complainant(s), and file identification name and/or number, etc.

SAFEGUARDS:

Access to the information, *e.g.,* electronic records, files, and data, in the Broadcast Station Public Inspection Files, which is housed in the FCC computer network databases, is posted on the Internet to be publicly accessible. Only the broadcast stations who upload information into the broadcast station files can alter their information. The FCC's computer network databases are protected by the FCC's security protocols, which include controlled access, passwords, and other IT security features and requirements. Information resident on the database servers is backed-up routinely onto magnetic media. Back-up tapes are stored on-site and at a secured off-site location.

RETENTION AND DISPOSAL:

The FCC will retain these records until a records schedule has been approved by the National Archives and Records Administration (NARA).

SYSTEM MANAGERS AND ADDRESS:

Address inquiries to the Media Bureau (MB), Federal Communications Commission (FCC), 445 12th Street SW., Washington, DC 20554.

NOTIFICATION PROCEDURE:

Address inquiries to the Media Bureau (MB), Federal Communications Commission (FCC), 445 12th Street SW., Washington, DC 20554.

RECORD ACCESS PROCEDURES:

Address inquiries to the Media Bureau (MB), Federal Communications Commission (FCC), 445 12th Street SW., Washington, DC 20554.

CONTESTING RECORD PROCEDURES:

Address inquiries to the Media Bureau (MB), Federal Communications Commission (FCC), 445 12th Street SW., Washington, DC 20554.

RECORD SOURCE CATEGORIES:

The sources for the information in the Broadcast Station Public Inspection Files include, but are not limited to the PII that may be included in the documents, records, and files that television broadcasters are required to submit to the FCC for posting in the FCC's on-line Broadcast Station Public Inspection Files as required by 47 U.S.C. 315; 47 CFR 73.3526 and 73.3527.

EXEMPTIONS CLAIMED FOR THE SYSTEM:

None.

Federal Communications Commission.

Marlene H. Dortch,

Secretary, Office of the Secretary, Office of Managing Director.

[FR Doc. 2012–13128 Filed 5–30–12; 8:45 am]

BILLING CODE 6712–01–P

FEDERAL COMMUNICATIONS COMMISSION

[WC Docket Nos. 10–90 and 05–337; DA 12–639]

Wireline Competition Bureau Announces Support Amounts for Connect America Fund Phase One Incremental Support

AGENCY: Federal Communications Commission.

ACTION: Notice; solicitation of comments.

SUMMARY: In this document, the Wireline Competition Bureau (Bureau), identifies the data sources it relied on and announce support amounts for CAF Phase I incremental support for 2012.

DATES: Carriers must file notices stating the amount of support each wishes to accept, and the areas by wire center and census block in which the carrier intends to deploy broadband, or stating that the carrier declines incremental support for 2012, no later than July 24, 2012.

ADDRESSES: You may submit notices stating the amount of support you wish to accept, identified by WC Docket Nos. 10–90 and 05–337, by any of the following methods:

- *Electronic Filers:* Comments may be filed electronically using the Internet by accessing the ECFS: *http://fjallfoss.fcc.gov/ecfs2/*.
- *Paper Filers:* Parties who choose to file by paper must file an original and four copies of each filing. If more than one docket or rulemaking number appears in the caption of this proceeding, filers must submit two additional copies for each additional docket or rulemaking number.
- *People with Disabilities:* To request materials in accessible formats for people with disabilities (Braille, large print, electronic files, audio format), send an email to *fcc504@fcc.gov* or call the Consumer & Governmental Affairs Bureau at (202) 418–0530 (voice), (202) 418–0432 (tty).

FOR FURTHER INFORMATION CONTACT: Joseph Cavender, Wireline Competition Bureau at (202) 418–1548 or TTY (202) 418–0484.

SUPPLEMENTARY INFORMATION:

1. The *USF/ICC Transformation Order and FNPRM,* 76 FR 76623, December 8, 2011, comprehensively reformed and modernized the universal service and intercarrier compensation systems. Among other things, the Commission established a transitional mechanism to distribute high-cost universal service support to price cap carriers, known as the Connect America Fund Phase I (CAF Phase I). In addition to freezing existing high-cost support for price cap carriers, the Commission adopted a process to distribute up to $300 million of additional, incremental support in 2012 among such carriers to advance broadband deployment. The Commission delegated to the Wireline Competition Bureau (Bureau) the task of performing the calculations necessary to determine support amounts and selecting the necessary data.

2. In an earlier Notice, 77 FR 9653, February 17, 2012, we sought comment on wire center data submitted by Windstream Communications that the carrier proposed we use for CAF Phase I. We also sought data for areas for which Windstream had not submitted data and sought comment on alternate approaches to generating sufficiently reliable data for such areas. In addition, because only the wire centers of price cap carriers and their affiliates would be relevant to the distribution of incremental high cost support; we sought comment on a proposed list of wire centers to include in our analysis. In a subsequent letter, we identified various additional data sources we might rely on. In this Notice, we identify the data sources we rely on and announce support amounts for CAF Phase I incremental support for 2012.

3. For wire centers in the contiguous territory of the United States plus Hawaii, we use the data submitted by Windstream. US Telecom, on behalf of nine holding companies of price cap carriers serving that area, filed comments supporting the use of those data, and provided a detailed explanation of the commercially available sources relied upon and the statistical techniques used to generate the data. No party objected to the use of such data.

4. For Alaska, we use data submitted by Alaska Communications Systems Group, Inc. for its wire centers in that state, which it developed using both internal and commercially available resources. No party objected to the use of those data.

5. For the Commonwealth of the Northern Marianas, we use mapping data and business count data submitted by Micronesian Telecom for its wire centers in that territory. No party objected to the use of those data. In addition, for household counts, we use Geolytics estimates data. For road feet, we use US Census TIGER data. We allocate census block data to wire centers based on the mapping data submitted by the carrier. We calculate business counts for each census block using data supplied by the carrier in conjunction with an estimation

technique intended to ensure that the carrier is not deprived of the opportunity to receive incremental support solely because we lack adequate data.

6. For the United States Virgin Islands, we use mapping data submitted by the Virgin Islands Telephone Company (Vitelco). No party objected to the use of those data. In addition, for household counts, we use Geolytics estimates. For road feet, we use US Census TIGER data. For business counts, we use data from the CostQuest Broadband Availability Tool. We allocate census block data to wire centers based on the mapping data submitted by the carrier.

7. No party submitted data for Puerto Rico. For our analysis, we use mapping data from TomTom (formerly Tele Atlas North America). For household counts, we use Geolytics estimates. For business counts, we use data from the CostQuest Broadband Availability Tool. For road feet, we use US Census TIGER data.

8. In addition, we adopt the following data sources for the lists of wire centers of price cap carriers and their affiliates to be included in our analysis. For the contiguous territory of the United States plus Hawaii, we use the list of wire centers submitted by US Telecom, which filed on behalf of the price cap carriers serving those areas. For Puerto Rico, we use the list of wire centers included in the CostQuest Broadband Availability Tool data. For all other areas, we use wire center information provided by the price cap carrier providing service in that area.

9. Using these data, allocated support amounts for 2012, by holding company, are as follows.

Company	Support amount
Alaska Communications Systems	$4,185,103
AT&T	47,857,148
CenturyLink	89,904,599
Cincinnati Bell	0
Consolidated Communications	421,247
Fairpoint Communications	4,856,858
Frontier Communications	71,979,104
Hawaiian Telcom	402,171
Virgin Islands Telephone Co. (Vitelco)	255,231
Micronesian Telecommunications	0
Puerto Rico Telephone Company	0
Verizon	19,734,224
Windstream Communications	60,404,310

10. No later than 90 days after release of this Notice, carriers must file notices stating the amount of support each wishes to accept, and the areas by wire center and census block in which the carrier intends to deploy broadband to meet its obligation, or stating that the carrier declines incremental support for 2012. We encourage carriers to file their notices in advance of the deadline. Copies of such notices must be filed with the Commission, USAC, the relevant state or territorial commissions, and any affected Tribal government.

11. Pursuant to the rules established by the Commission in the *Order,* carriers must deploy broadband to a number of unserved locations equal to the amount of incremental support each accepts, divided by $775. Carriers accepting incremental support must certify that deployment funded through CAF Phase I incremental support will occur in areas shown as unserved by any other carrier on the National Broadband Map, and that, to the best of the carrier's knowledge, the locations to be served are, in fact, unserved. Carriers must further certify that the carrier's current capital improvement plan did not already include plans to complete broadband deployment within the next three years to the locations to be counted to satisfy the deployment obligation, and that incremental support will not be used to satisfy any merger commitment or similar obligation. Carriers must complete deployment to two-thirds of the required number of locations within two years of the date they accept support, and to all required locations within three years.

12. *Paperwork Reduction Act.* This document contains modified information collection requirements subject to the Paperwork Reduction Act of 1995 (PRA), Public Law 104–13. It was submitted to the Office of Management and Budget (OMB) for review under Section 3507(d) of the PRA. OMB, the general public, and other Federal agencies were invited to comment on the modified information collection requirements contained in this proceeding. OMB approved the requirements on April 16, 2012.

13. *Congressional Review Act.* The Commission will send a copy of this notice to Congress and the Government Accountability Office pursuant to the Congressional Review Act.

14. *Final Regulatory Flexibility Certification.* The Regulatory Flexibility Act (RFA) requires that agencies prepare a regulatory flexibility analysis for notice-and-comment rulemaking proceedings, unless the agency certifies that ''the rule will not have a significant economic impact on a substantial number of small entities.'' The RFA generally defines ''small entity'' as having the same meaning as the terms ''small business,'' ''small organization,'' and ''small governmental jurisdiction.'' In addition, the term ''small business'' has the same meaning as the term ''small business concern'' under the Small Business Act. A small business concern is one which: (1) Is independently owned and operated; (2) is not dominant in its field of operation; and (3) satisfies any additional criteria established by the Small Business Administration (SBA). This Public Notice selects data sources necessary to implement the Connect America Fund Phase I incremental support mechanism adopted by the Commission in the *USF/ICC Transformation Order,* which provides additional support to price cap carriers to deploy broadband facilities. This Public Notice also notifies carriers of the support for which they are eligible. It does not modify the rules governing the Connect America Fund Phase I incremental support mechanism. Selecting these data sources and publishing eligible support amounts imposes no new burden on any company and has no negative economic impact on any company. Accordingly, we certify that the measures taken herein will not have a significant impact on a substantial number of small entities.

The Commission will send a copy of this Public Notice, including this certification, to the Chief Counsel for Advocacy of the Small Business Administration. In addition, the notice (or a summary thereof) and certification will be published in the **Federal Register**.

Federal Communications Commission.

Trent Harkrader,

Division Chief, Telecommunications Access Policy Division, Wireline Competition Bureau.

[FR Doc. 2012–13127 Filed 5–30–12; 8:45 am]

BILLING CODE 6712–01–P

FEDERAL DEPOSIT INSURANCE CORPORATION

Agency Information Collection Activities: Proposed Collection Renewal; Comment Request

AGENCY: Federal Deposit Insurance Corporation (FDIC).

ACTION: Notice and request for comment.

SUMMARY: The FDIC, as part of its continuing effort to reduce paperwork and respondent burden, invites the general public and other Federal agencies to take this opportunity to comment on the renewal of an existing information collection, as required by the Paperwork Reduction Act of 1995 (44 U.S.C. chapter 35). Currently, the FDIC is soliciting comment on renewal

of the information collection described below.

DATES: Comments must be submitted on or before July 30, 2012.

ADDRESSES: Interested parties are invited to submit written comments to the FDIC by any of the following methods:

- *http://www.FDIC.gov/regulations/laws/federal/notices.html.*
- *Email: comments@fdic.gov.* Include the name of the collection in the subject line of the message.
- *Mail:* Gary A. Kuiper (202.898.3877), Counsel, Room NYA–5046, Federal Deposit Insurance Corporation, 550 17th Street NW., Washington, DC 20429.
- *Hand Delivery:* Comments may be hand-delivered to the guard station at the rear of the 17th Street Building (located on F Street), on business days between 7:00 a.m. and 5:00 p.m.

All comments should refer to the relevant OMB control number. A copy of the comments may also be submitted to the OMB desk officer for the FDIC: Office of Information and Regulatory Affairs, Office of Management and Budget, New Executive Office Building, Washington, DC 20503.

FOR FURTHER INFORMATION CONTACT: Gary A. Kuiper, at the FDIC address above.

SUPPLEMENTARY INFORMATION: Proposal to renew the following currently-approved collection of information:

Title: Home Mortgage Disclosure Act.

OMB Number: 3064–0046.

Affected Public: Insured state nonmember banks.

Frequency of Response: On occasion.

Estimated Number of Respondents: 2,773.

Estimated Number of Responses: 1,063,700.

Estimated Time per Response: 5 minutes.

Estimated Total Annual Burden: 88,642 hours.

General Description: To permit the FDIC to detect discrimination in residential mortgage lending, certain insured state nonmember banks are required by FDIC Regulation 12 CFR 338 to maintain various data on home loan applicants.

Request for Comment

Comments are invited on: (a) Whether the collection of information is necessary for the proper performance of the FDIC's functions, including whether the information has practical utility; (b) the accuracy of the estimates of the burden of the information collection, including the validity of the methodology and assumptions used; (c) ways to enhance the quality, utility, and clarity of the information to be collected; and (d) ways to minimize the burden of the information collection on respondents, including through the use of automated collection techniques or other forms of information technology. All comments will become a matter of public record.

Federal Deposit Insurance Corporation.

Dated at Washington, DC, this 25th day of May 2012.

Robert E. Feldman,

Executive Secretary.

[FR Doc. 2012–13195 Filed 5–30–12; 8:45 am]

BILLING CODE 6714–01–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 the 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 the agreements are available through the Commission's Web site (*www.fmc.gov*) or by contacting the Office of Agreements at (202) 523–5793 or *tradeanalysis@fmc.gov.*

Agreement No.: 011516–008.

Title: Voluntary Intermodal Sealift Discussion Agreement.

Parties: American President Lines, Ltd.; CP Ships USA, LLC; Crowley Liner Services, Inc.; Crowley Marine Services, Inc.; Farrell Lines, Inc.; Matson Navigation Company; and Totem Ocean Trailer Express, Inc.

Filing Party: Wayne R. Rohde, Esquire; Cozen O'Connor; 1627 I Street NW., Suite 1100; Washington, DC 20006–4007.

Synopsis: The amendment deletes Maersk Line Limited and Maersk Line, Inc. as parties to the agreement.

Agreement No.: 012061–004.

Title: CMA CGM/Maersk Line Space Charter, Sailing and Cooperative Working Agreement Western Mediterranean-U.S. East Coast.

Parties: CMA CGM, S.A. and A.P. Moller-Maersk A/S.

Filing Party: Wayne R. Rohde, Esquire; Cozen O'Connor; 1627 I Street NW., Suite 1100; Washington, DC 20006–4007.

Synopsis: The amendment would add Morocco to the geographic scope of the agreement.

Agreement No.: 012171.

Title: CMA CGM/SSL Puerto Rico-Leeward Islands Space Charter Agreement.

Parties: CMA CGM S.A. and Sea Star Line LLC.

Filing Party: Wayne R. Rohde, Esquire; Cozen O'Connor; 1627 I Street NW., Suite 1100; Washington, DC 20006–4007.

Synopsis: The agreement authorizes CMA to charter space to Sea Star in the trade between Puerto Rico on the one hand, and the U.S. Virgin Islands and Saint Maarten on the other hand.

Agreement No.: 012172.

Title: Maersk Line/MSC Caribbean Space Charter Agreement.

Parties: A.P. Moller-Maersk A/S trading under the name Maersk Line and Mediterranean Shipping Company S.A.

Filing Party: Wayne R. Rohde, Esquire; Cozen O'Connor; 1627 I Street NW., Suite 1100; Washington, DC 20006–4007.

Synopsis: The agreement would authorize Maersk Line to charter space to MSC in the trade between ports in Puerto Rico and ports in the Dominican Republic and Panama.

By Order of the Federal Maritime Commission.

Dated: May 24, 2012.

Karen V. Gregory,

Secretary.

[FR Doc. 2012–13136 Filed 5–30–12; 8:45 am]

BILLING CODE P

FEDERAL MARITIME COMMISSION

Ocean Transportation Intermediary License Applicants

Notice is hereby given that the following applicants have filed with the Federal Maritime Commission an application for a license as a Non-Vessel-Operating Common Carrier (NVO) and/or Ocean Freight Forwarder (OFF)—Ocean Transportation Intermediary (OTI) pursuant to section 19 of the Shipping Act of 1984 as amended (46 U.S.C. chapter 409 and 46 CFR 515). Notice is also hereby given of the filing of applications to amend an existing OTI license or the Qualifying Individual (QI) for a license.

Interested persons may contact the Office of Transportation Intermediaries, Federal Maritime Commission, Washington, DC 20573, by telephone at (202) 523–5843 or by email at *OTI@fmc.gov.*

Agunsa Logistics & Distribution (Los Angeles), Inc. (NVO & OFF), 19600 South Alameda Street, Rancho Dominguez, CA 90221, *Officers:* Eduardo Cabello, Vice President (Qualifying Individual), Rodrigo Jimenez, President, *Application Type:* QI Change.

American Global Logistics LLC dba AGL (NVO & OFF), 3399 Peachtree Road NE., #1130, Atlanta, GA 30326, *Officers:* Chad J. Rosenberg, President/CEO (Qualifying Individual), Otto J. Valdes, Vice President, *Application Type:* Trade Name Change.

Ark Shipping Line Limited Liability Company (NVO & OFF), 250 Lackland Drive, Suite 6, Middlesex, NJ 08846, *Officer:* Fawwad Mohammad, Chief Executive Manager (Qualifying Individual), *Application Type:* New NVO & OFF License.

Asencoex, LLC (NVO & OFF), 7788 NW 71st Street, Miami, FL 33166, *Officers:* Juan P. Constain, Managing Member (Qualifying Individual), Natalia I. Rondinel, Managing Member, *Application Type:* New NVO & OFF License.

Blue Axis Shipping & Freight Inc (NVO), 1109 Burnett Drive, Allen, TX 75002, *Officer:* Sinu Jacob, President/Secretary/Treasurer (Qualifying Individual), *Application Type:* New NVO License.

Blue Global Line, Inc. dba CFS Logistics (NVO), 455 E. State Parkway, #105, Schaumburg, IL 60173, *Officers:* Kook (A.K.A. Joseph) S. Lee, President/Treasurer/Secretary (Qualifying Individual), Eun J. Lim, Vice President, *Application Type:* New NVO License.

BM Forwarding Inc. (OFF), 1290 Maple View Drive, Pomona, CA 91766, *Officer:* Mei Zhu, President/CEO/Secretary/CFO (Qualifying Individual), *Application Type:* New OFF License.

Brilliant Group Logistics Corp. (NVO), 159 N. Central Avenue, Valley Stream, NY 11580, *Officer:* Shuping Wang, President/VP/Sec/Treasurer (Qualifying Individual), *Application Type:* New NVO License.

Concord Atlantic Inc. dba Concord Atlantic Shipping (NVO & OFF) 10095 Washington Blvd., North, #211 Laurel, MD 20723, *Officer:* Olufemi A. Asabi President, (Qualifying Individual), *Application Type:* New NVO & OFF License.

CTL Lax, Inc. (NVO), 10622 Tammy Street, Cypress, CA 90630, *Officers:* Jason Hsu, Director/Secretary/Treasurer/CFO (Qualifying Individual), Sin F. Chan, Director/President, *Application Type:* New NVO License.

Eagle Van Lines, Inc. (OFF), 5041 Beech Place, Temple Hills, MD 20748, *Officers:* George Georgakopoulos, President (Qualifying Individual), Marika Georgakopoulos, Secretary, *Application Type:* QI Change.

EZ Forwarding LLC (NVO & OFF), 3050 North 29th Court, Hollywood, FL 33020, *Officer:* Frances M. Simons, Vice President (Qualifying Individual), *Application Type:* Trade Name Change.

Fast Global Logistics, LLC (NVO & OFF), 3505 NW 113th Court, Miami, FL 33178, *Officers:* Rayani A. Vllias, Member/Manager/President (Qualifying Individual), Anderson Miera, Member/Manager/Vice President, *Application Type:* New NVO & OFF License.

ISS Marine Services, Inc. dba Inchcape Shipping Services (NVO & OFF), 11 N. Water Street, #9290, Mobile, AL 36602, *Officers:* Elaine T. Dearmond, Vice President (Qualifying Individual), Lar D. Westerberg, CEO, *Application Type:* Add NVO Service.

Jo-Sak Shipping USA, Inc. (NVO & OFF), 3100 Arapahoe Avenue, #104, Boulder, CO 80303, *Officers:* Pauline Yagjhiayan, President (Qualifying Individual), Duncan Alex, Chairman, *Application Type:* Name Change.

Quasar Logistics Inc. (NVO), 18460 Jamaica Avenue, Hollis, NY 11423, *Officers:* Rene G. Madrazo, Chief Logistics Officer (Qualifying Individual), Qaiser Choudri, President, *Application Type:* New NVO License.

Shipping Logistics, LLC (NVO & OFF), 3340–C Greens Road, #200, Houston, TX 77032, *Officer:* Mary K. Francis, Manager (Qualifying Individual), *Application Type:* Add NVO Service.

Tradelanes, Inc. (NVO & OFF), 61 Saint Joseph Street, Suite 1000, Mobile, AL 36602, *Officers:* Raymond K. Jones, Vice President (Qualifying Individual), Lloyd C. Garrison, President, *Application Type:* QI Change.

US Pacific Transportation Group, Inc. (NVO), 1290 Maple View Drive, Pomona, CA 91766, *Officer:* Mei Zhu, President/CEO/Secretary/CFO (Qualifying Individual), *Application Type:* New NVO License.

W8 Shipping LLC (NVO & OFF), 8 Aviation Court, Savannah, GA 31408, *Officers:* Darius Ziulpa, Member (Qualifying Individual), Gediminas Garmus, Member/Manager, *Application Type:* Add NVO Service.

Waterline International Logistics, Inc. (NVO & OFF), 24178 Alicia Parkway, Mission Viejo, CA 92691, *Officer:* Khalid E. Fahssi, Pres/CEO/Treas/CFO/Sec/VP (Qualifying Individual), *Application Type:* New NVO & OFF License.

Dated: May 25, 2012.

Rachel E. Dickon,

Assistant Secretary.

[FR Doc. 2012–13216 Filed 5–30–12; 8:45 am]

BILLING CODE 6730–01–P

FEDERAL MARITIME COMMISSION

Ocean Transportation Intermediary License Revocation

The Federal Maritime Commission hereby gives notice that the following Ocean Transportation Intermediary licenses have been revoked pursuant to section 19 of the Shipping Act of 1984 (46 U.S.C. Chapter 409) and the regulations of the Commission pertaining to the licensing of Ocean Transportation Intermediaries, 46 CFR part 515, effective on the corresponding date shown below:

License Number: 004661N.
Name: Jacob Fleishman Transportation, Inc.
Address: 1177 NW 81st Street, Miami, FL 33150.
Date Revoked: April 25, 2012.
Reason: Voluntarily surrendered license.

License Number: 020163N.
Name: Global Services of Nevada, Inc.
Address: 1607 Guilford Drive, Henderson, NV 89014.
Date Revoked: May 4, 2012.
Reason: Voluntarily surrendered license.

License Number: 021803NF.
Name: Skyline Customs Services, LLC.
Address: 7539 NW 52nd Street, Miami, FL 33166.
Date Revoked: April 30, 2012.
Reason: Voluntarily surrendered license.

Vern W. Hill,

Director, Bureau of Certification and Licensing.

[FR Doc. 2012–13215 Filed 5–30–12; 8:45 am]

BILLING CODE 6730–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Office of the Secretary

Findings of Research Misconduct

AGENCY: Office of the Secretary, HHS.

ACTION: Notice.

SUMMARY: Notice is hereby given that the Office of Research Integrity (ORI) has taken final action in the following case:

Juan Ma, Ph.D., Brigham and Women's Hospital and Harvard Medical

School: Based on evidence and findings of an inquiry conducted jointly by Brigham and Women's Hospital (BWH) and Harvard Medical School (HMS) and additional evidence gathered by the Office of Research Integrity (ORI) during its oversight review, ORI found that Dr. Juan Ma, former Research Fellow, BWU, engaged in research misconduct in research supported by National Cancer Institute (NCI), National Institutes of Health (NIH), grant 5 P01 CA120964.

ORI found that the Respondent knowingly and intentionally fabricated and falsified data in portions of figures in an unpublished manuscript titled ''TSC1 loss synergizes with KRAS activation in lung cancer development and confers rapamycin sensitivity'' by M.-C. Liang, J. Ma, L. Chen, P. Kozlowski, W. Qin, D. Li, T. Shimamura, M.L. Sos, R. Thomas, D. Neil Hayes, M. Meyerson, D.J. Kwiatkowski, and K.-K. Wong, submitted to the *Journal of Clinical Investigation* (*JCI*) on August 5, 2008, and in revised form on October 21, 2008 (hereafter referred to as the ''*JCI* manuscript''). Specifically, Respondent committed research misconduct by knowingly and intentionally:

• Falsifying and/or fabricating those portions of the immunoblots in *JCI* manuscript Figure 1C, to show that in Tscl$^{L/L}$ and Tsc$^{L/+}$ mouse lung cancer cells compared with KRAS induced lung cancer cells, there were reduced Tsc1 and Tsc2 protein levels, reduced phospho-AKT–S473 levels, and increased phospho-S6–S249/244 levels, consistent with the hypothesis that introduction of the Tsc1^{L} gene resulted in mTORC1 activation.

• Falsifying and/or fabricating those portions of the immunoblots in Figure 3A of the *JCI* manuscript to show data consistent with the hypothesized TNS null signaling lung tumor cells: Functional loss of Tsc1/Tsc2, high phospho-S6–S249/244 levels, and low phospho-AKT–S473, with recovery of phospho-AKT–S473 after Rapamycin treatment.

• Falsifying and/or fabricating those portions of the immunoblots in Figure 3B of the *JCI* manuscript by (i) adding a band in the Tsc2 lane for control cells for the IP blot, and (ii) weakening the Tsc2 band for one of the tumor lysates.

• Falsifying and/or fabricating immunoblots in Figures 5A and 5B of the *JCI* manuscript so that the data appeared to indicate that TSC reconstitution in TSC null (TNS) cell lines led to reduction of pS6–S240/244 levels during serum deprivation (in the absence of growth factors), as well as increased pAKT(S473) levels in response to serum stimulation.

• The *JCI* manuscript was accepted by *JCI* on December 8, 2008, but it was withdrawn by one of the authors on January 6, 2009.

ORI found that Respondent's knowing and intentional falsification and fabrication of data constitutes research misconduct within the meaning of 42 CFR 93.103.

The following administrative actions have been implemented for a period of three (3) years, beginning on May 12, 2012:

(1) Any institution that submits an application for U.S. Public Health Service (PHS) support for a research project on which Respondent's participation is proposed or that uses him in any capacity on PHS-supported research must concurrently submit a plan for supervision of his duties to the funding agency for approval; the supervisory plan must be designed to ensure the scientific integrity of his research contribution; Respondent must ensure that a copy of the supervisory plan is also submitted to ORI by the institution; Respondent will not participate in any PHS-supported research until such a supervisory plan is submitted to ORI;

(2) Respondent will ensure that any institution employing him submits, in conjunction with application for PHS funds or any report, manuscript, or abstract of PHS-funded research in which he is involved, a certification that the data provided by him are accurately reported in the application or report; Respondent must ensure that the institution send the certification to ORI; this certification shall be submitted no later than one month before funding and concurrently with any report, manuscript, or abstract; and

(3) Respondent 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 a 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.

John Dahlberg,

Director, Division of Investigative Oversight, Office of Research Integrity.

[FR Doc. 2012–13126 Filed 5–30–12; 8:45 am]

BILLING CODE 4150–31–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Disease Control and Prevention

Advisory Board on Radiation and Worker Health (ABRWH or Advisory Board), National Institute for Occupational Safety and Health (NIOSH)

In accordance with section 10(a)(2) of the Federal Advisory Committee Act (Pub. L. 92–463), and pursuant to the requirements of 42 CFR 83.15(a), the Centers for Disease Control and Prevention (CDC), announces the following meeting of the aforementioned committee:

Board Public Meeting Times and Dates (All times are Mountain Time):
8:15 a.m.–5:15 p.m., June 19, 2012.
8:15 a.m.–5:45 p.m., June 20, 2012.
8:15 a.m.–12 p.m., June 21, 2012.

Public Comment Times and Dates (All times are Mountain Time):
5:15 p.m.–6:15 p.m.*, June 19, 2012.
6 p.m.–7 p.m.*, June 20, 2012.

* Please note that the public comment periods may end before the times indicated, following the last call for comments. Members of the public who wish to provide public comments should plan to attend public comment sessions at the start times listed.

Place: Courtyard Santa Fe, 3347 Cerrillos Road, Santa Fe, New Mexico 87507, Telephone: (800) 777–3347, Fax: (505) 473–5128. Audio Conference Call via FTS Conferencing, the USA toll-free, dial-in number is 1–866–659–0537 with a pass code of 9933701.

Status: Open to the public, limited only by the space available. The meeting space accommodates approximately 150 people.

Background: The Advisory Board was established under the Energy Employees Occupational Illness Compensation Program Act of 2000 to advise the President on a variety of policy and technical functions required to implement and effectively manage the new compensation program. Key functions of the Advisory Board include providing advice on the development of probability of causation guidelines which have been promulgated by the Department of Health and Human Services (HHS) as a final rule, advice on methods of dose reconstruction which have also been promulgated by HHS as a final rule, advice on the scientific validity and quality of dose estimation and reconstruction efforts being performed for purposes of the compensation program, and advice on petitions to add classes of workers to the Special Exposure Cohort (SEC).

In December 2000, the President delegated responsibility for funding, staffing, and operating the Advisory Board to HHS, which subsequently delegated this authority to the CDC. NIOSH implements this responsibility for CDC. The charter was issued on August 3, 2001, renewed at appropriate intervals, and will expire on August 3, 2013.

Purpose: This Advisory Board is charged with (a) providing advice to the Secretary, HHS, on the development of guidelines under Executive Order 13179; (b) providing advice to the Secretary, HHS, on the scientific validity and quality of dose reconstruction efforts performed for this program; and (c) upon request by the Secretary, HHS, advise the Secretary on whether there is a class of employees at any Department of Energy facility who were exposed to radiation but for whom it is not feasible to estimate their radiation dose, and on whether there is reasonable likelihood that such radiation doses may have endangered the health of members of this class.

Matters To Be Discussed: The agenda for the Advisory Board meeting includes: NIOSH Program Update; Department of Labor Program Update; Department of Energy Program Update; NIOSH 10-Year Program Review Implementation; SEC petitions for: Winchester Engineering and Analytical Center (Winchester, MA), Weldon Spring Plant (Weldon Spring, MO), Hanford (1972–1983), Los Alamos National Laboratory, General Steel Industries (Granite City, IL), Clarksville Facility (Clarksville, TN), Mound Plant, Titanium Alloys Manufacturing (Niagara Falls, NY), and Medina Facility (San Antonio, TX); Non-qualifying SEC Petitions and SEC Petitions Status Update; Linde Ceramics Work Group Site Profile Review; and Board Work Sessions.

The agenda is subject to change as priorities dictate.

In the event an individual cannot attend, written comments may be submitted in accordance with the redaction policy provided below. Any written comments received will be provided at the meeting and should be submitted to the contact person below well in advance of the meeting.

Policy on Redaction of Board Meeting Transcripts (Public Comment): (1) If a person making a comment gives his or her name, no attempt will be made to redact that name. (2) NIOSH will take reasonable steps to ensure that individuals making public comment are aware of the fact that their comments (including their name, if provided) will appear in a transcript of the meeting posted on a public Web site. Such reasonable steps include: (a) A statement read at the start of each public comment period stating that transcripts will be posted and names of speakers will not be redacted; (b) A printed copy of the statement mentioned in (a) above will be displayed on the table where individuals sign up to make public comments; (c) A statement such as outlined in (a) above will also appear with the agenda for a Board Meeting when it is posted on the NIOSH Web site; (d) A statement such as in (a) above will appear in the **Federal Register** Notice that announces Board and Subcommittee meetings. (3) If an individual in making a statement reveals personal information (e.g., medical information) about themselves that information will not usually be redacted. The NIOSH FOIA coordinator will, however, review such revelations in accordance with the Freedom of Information Act and the Federal Advisory Committee Act and if deemed appropriate, will redact such information. (4) All disclosures of information concerning third parties will be redacted. (5) If it comes to the attention of the DFO that an individual wishes to share information with the Board but objects to doing so in a public forum, the DFO will work with that individual, in accordance with the Federal Advisory Committee Act, to find a way that the Board can hear such comments.

CONTACT PERSON FOR MORE INFORMATION: Theodore Katz, Executive Secretary, NIOSH, CDC, 1600 Clifton Road, M/S E–20, Atlanta, Georgia 30333, telephone: (513) 533–6800, toll free: 1 (800) CDC–INFO, email: *dcas@cdc.gov.*

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 the Centers for Disease Control and Prevention and the Agency for Toxic Substances and Disease Registry.

Dated: May 23, 2012.

Elaine L. Baker,

Director, Management Analysis and Services Office, Centers for Disease Control and Prevention.

[FR Doc. 2012–13154 Filed 5–30–12; 8:45 am]

BILLING CODE 4163–18–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Medicare & Medicaid Services

[Document Identifier: CMS–10436 and CMS–855B]

Agency Information Collection Activities: Proposed Collection; Comment Request

AGENCY: Centers for Medicare & Medicaid Services, HHS.

In compliance with the requirement of section 3506(c)(2)(A) of the Paperwork Reduction Act of 1995, the Centers for Medicare & Medicaid Services (CMS) is publishing the following summary of proposed collections for public comment. Interested persons are invited to send comments regarding this burden estimate or any other aspect of this collection of information, including any of the following subjects: (1) The necessity and utility of the proposed information collection for the proper performance of the agency's functions; (2) the accuracy of the estimated burden; (3) ways to enhance the quality, utility, and clarity of the information to be collected; and (4) the use of automated collection techniques or other forms of information technology to minimize the information collection burden.

1. *Type of Information Collection Request:* New collection; *Title of Information Collection:* Evaluation of the Multi-Payer Advanced Primary Care Practice Demonstration; Use: On September 16, 2009, the Department of Health and Human Services announced the establishment of the Multi-Payer Advanced Primary Care Practice (MAPCP) Demonstration, under which Medicare joined Medicaid and private insurers as a payer participant in state-sponsored initiatives to promote the principles that characterize advanced primary care, often referred to as the ''patient-centered medical home'' (PCMH). CMS selected eight states to participate in this demonstration: Maine, Vermont, Rhode Island, New York, Pennsylvania, North Carolina, Michigan, and Minnesota. These states vary on a number of important dimensions, such as features of their public (Medicaid) and private insurance markets, delivery system, prior experience with medical home initiatives, and nature of their state-sponsored multi-payer initiative.

CMS is conducting an evaluation of the demonstration to assess the effects of advanced primary care practice when supported by Medicare, Medicaid, and private health plans. As part of this evaluation, qualitative and quantitative data will be collected and analyzed to answer research questions focused on: (1) State initiative features and implementation, including various payment models; (2) practice characteristics, particularly medical home transformation; and (3) outcomes, including access to and coordination of care, clinical quality of care and patient safety, beneficiary experience with care, patterns of utilization, Medicare and Medicaid expenditures, and budget neutrality. This information will help CMS decide whether the MAPCP Demonstration model should be expanded under Medicare, and if so, what modifications and supports would be needed to implement similar innovations in other states and practices in the future. *Form Number:* CMS–10436 (OCN: 0938–New); *Frequency:* Yearly; *Affected Public:* Individuals and households; *Number of Respondents:* 472 ; *Total Annual Responses:* 472; *Total Annual Hours:* 478 (For policy questions regarding this collection contact Suzanne Goodwin at 410–786–0226. For all other issues call 410–786–1326.)

2. *Type of Information Collection Request:* New collection; *Title of Information Collection:* Medicare Enrollment Application for Clinics/Group Practice and Certain Other Suppliers; *Use:* The primary function of the CMS–855B enrollment application for Clinics, Group Practices and Certain Other Suppliers is to gather information from the organization that tells us what it is, whether it meets certain qualifications to be a health care supplier, where it renders services and information necessary to establish the correct claims payment. The goal of evaluating and revising the CMS–855B enrollment application is to simplify and clarify the information collection without jeopardizing our need to collect specific information. The majority of the revisions are very minor in nature such as spelling and formatting corrections, removal of duplicate fields and instruction clarification for the organization/group. The Sections and Sub-Sections within the form are also being re-numbered and re-sequenced to create a more logical flow of the data collection. In addition, CMS is adding a data collection for an address to mail the periodic request for the revalidation of enrollment information (only if it differs from other addresses currently collected). Other than the revalidation mailing address described above, new data being collected in this revision package is a checkbox indicating whether or not an organization is wholly owned or operated by a hospital, the inclusion of a new supplier type (Centralized Flu Biller) and information on, if applicable, where the supplier stores its patient records electronically. *Form Number:* CMS–855B (OCN: 0938–New); *Frequency:* Yearly; *Affected Public:* Individuals and households; *Number of Respondents:* 31,000; *Total Annual Responses:* 31,000; *Total Annual Hours:* 103,000 (For policy questions regarding this collection contact Kim McPhillips at 410–786–5374. For all other issues call 410–786–1326.)

To obtain copies of the supporting statement and any related forms for the proposed paperwork collections referenced above, access CMS' Web site address at *http://www.cms.hhs.gov/PaperworkReductionActof1995,* or Email your request, including your address, phone number, OMB number, and CMS document identifier, to *Paperwork@cms.hhs.gov,* or call the Reports Clearance Office at (410) 786–1326.

In commenting on the proposed information collections please reference the document identifier or OMB control number. To be assured consideration, comments and recommendations must be submitted in one of the following ways by *July 30, 2012:*

1. *Electronically.* You may submit your comments electronically to *http://www.regulations.gov.* Follow the instructions for ''Comment or Submission'' or ''More Search Options'' to find the information collection document(s) accepting comments.

2. *By regular mail.* You may mail written comments to the following address: CMS, Office of Strategic Operations and Regulatory Affairs, Division of Regulations Development, Attention: Document Identifier/OMB Control Number________, Room C4–26–05, 7500 Security Boulevard, Baltimore, Maryland 21244–1850.

Dated: May 25, 2012.

Martique Jones,

Director, Regulations Development Group, Division B, Office of Strategic Operations and Regulatory Affairs.

[FR Doc. 2012–13207 Filed 5–30–12; 8:45 am]

BILLING CODE 4120–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Medicare & Medicaid Services

[Document Identifier: CMS–R–305]

Agency Information Collection Activities: Submission for OMB Review; Comment Request

AGENCY: Centers for Medicare & Medicaid Services, HHS.

In compliance with the requirement of section 3506(c)(2)(A) of the Paperwork Reduction Act of 1995, the Centers for Medicare & Medicaid Services (CMS), Department of Health and Human Services, is publishing the following summary of proposed collections for public comment. Interested persons are invited to send comments regarding this burden estimate or any other aspect of this collection of information, including any of the following subjects: (1) The necessity and utility of the proposed information collection for the proper performance of the Agency's function; (2) the accuracy of the estimated burden; (3) ways to enhance the quality, utility, and clarity of the information to be collected; and (4) the use of automated collection techniques or other forms of information technology to minimize the information collection burden.

1. *Type of Information Collection Request:* Revision of a currently approved collection. *Title of Information Collection:* External Quality Review Protocols. *Use:* The results of Medicare reviews, Medicare accreditation services, and Medicaid external quality reviews will be used by States in assessing the quality of care provided to Medicaid beneficiaries by managed care organizations and to provide information on the quality of care provided to the general public upon request. Protocols 1, 2, 3, 4, 5, 7, and the External Quality Review Background have been revised since the publication of the 60-day **Federal Register** notice on February 17, 2012 (77 FR 9661). All of the revised protocols associated with the 60-day notice and this 30-day notice are in draft and must not be used until they are approved by OMB through the PRA process. *Form Number:* CMS–R–305 (OCN 0938–0786). *Frequency of Reporting:* Yearly. *Affected Public:* State, Local or Tribal Governments. *Number of Respondents:* 42. *Total Annual Responses:* 70. *Total Annual Hours:* 415,643. (For policy questions regarding this collection contact Gary B. Jackson at 410–786–

1218. For all other issues call 410–786–1326.)

To obtain copies of the supporting statement and any related forms for the proposed paperwork collections referenced above, access CMS Web site address at *http://www.cms.hhs.gov/PaperworkReductionActof1995,* or email your request, including your address, phone number, OMB number, and CMS document identifier, to *Paperwork@cms.hhs.gov,* or call the Reports Clearance Office on (410) 786–1326.

To be assured consideration, comments and recommendations for the proposed information collections must be received by the OMB desk officer at the address below, no later than 5 p.m. on July 2, 2012. OMB, Office of Information and Regulatory Affairs, Attention: CMS Desk Officer, *Fax Number:* (202) 395–6974, *Email: OIRA_submission@omb.eop.gov.*

Dated: May 25, 2012.

Martique Jones,

Director, Regulations Development Group, Division-B, Office of Strategic Operations and Regulatory Affairs.

[FR Doc. 2012–13206 Filed 5–30–12; 8:45 am]

BILLING CODE 4120–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA–2012–N–0495]

Agency Information Collection Activities; Proposed Collection; Comment Request; Experimental Study on Consumer Responses to Nutrition Facts Labels With Various Footnote Formats and Declaration of Amount of Added Sugars

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

SUMMARY: The Food and Drug Administration (FDA) is announcing an opportunity for public comment on the proposed collection of certain information by the Agency. Under the Paperwork Reduction Act of 1995 (the PRA), Federal Agencies are required to publish notice in the **Federal Register** concerning each proposed collection of information and to allow 60 days for public comment in response to the notice. This notice solicits comments on a study entitled ‘‘Experimental Study on Consumer Responses to Nutrition Facts Labels With Various Footnote Formats and Declaration of Amount of Added Sugars.’’

DATES: Submit either electronic or written comments on the collection of information by July 30, 2012.

ADDRESSES: Submit electronic comments on the collection of information to *http://www.regulations.gov*. Submit written comments on the collection of information to the Division of Dockets Management (HFA–305), Food and Drug Administration, 5630 Fishers Lane, Rm. 1061, Rockville, MD 20852. All comments should be identified with the docket number found in brackets in the heading of this document.

FOR FURTHER INFORMATION CONTACT: Domini Bean, Office of Information Management, Food and Drug Administration, 1350 Piccard Dr., PI50–400T, Rockville, MD 20850, *domini.bean@fda.hhs.gov*.

SUPPLEMENTARY INFORMATION: Under the PRA (44 U.S.C. 3501–3520), Federal Agencies must obtain approval from the Office of Management and Budget (OMB) for each collection of information they conduct or sponsor. ‘‘Collection of information’’ is defined in 44 U.S.C. 3502(3) and 5 CFR 1320.3(c) and includes Agency requests or requirements that members of the public submit reports, keep records, or provide information to a third party. Section 3506(c)(2)(A) of the PRA (44 U.S.C. 3506(c)(2)(A)) requires Federal Agencies to provide a 60-day notice in the **Federal Register** concerning each proposed collection of information before submitting the collection to OMB for approval. To comply with this requirement, FDA is publishing notice of the proposed collection of information set forth in this document.

With respect to the following collection of information, FDA invites comments on these topics: (1) Whether the proposed collection of information is necessary for the proper performance of FDA's functions, including whether the information will have practical utility; (2) the accuracy of FDA'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 respondents, including through the use of automated collection techniques, when appropriate, and other forms of information technology.

Experimental Study on Consumer Responses to Nutrition Facts Labels With Various Footnote Formats and Declaration of Amount of Added Sugars—(OMB Control Number 0910–New)

I. Background

Under the Nutrition Labeling and Education Act of 1990 (Pub. L. 101–535), the Nutrition Facts label is required on most packaged foods and this information must be provided in a specific format in accordance with the provisions of § 101.9 (21 CFR 101.9). When FDA was determining which Nutrition Facts label format to require, the Agency undertook consumer research to evaluate alternatives (Refs. 1 to 3). More recently, FDA conducted qualitative consumer research on the format of the Nutrition Facts label on behalf of the Agency's Obesity Working Group (Ref. 4), which was formed in 2003 and tasked with outlining a plan to help confront the problem of obesity in the United States (Ref. 5). In addition to conducting consumer research, in the **Federal Register** of November 2, 2007 (72 FR 62149) FDA issued an Advance Notice of Proposed Rulemaking (ANPRM) entitled, ‘‘Food Labeling: Revision of Reference Values and Mandatory Nutrients’’ (the 2007 ANPRM), which requested comments on a variety of topics related to a future proposed rule to update the presentation of nutrients and content of nutrient values on food labels. In the 2007 ANPRM, the Agency included a request for comments on how consumers use the percent Daily Value in the Nutrition Facts label when evaluating the nutritional content of food items and making purchases.

Research has suggested that consumers use the Nutrition Facts label in various ways, including, but not limited to, using the Nutrition Facts label to determine if products are high or low in a specific nutrient and to compare products (Ref. 6). One component of the Nutrition Facts label that serves as an aid in these uses is the percent Daily Value. Early consumer research indicated that the percent Daily Value format improved consumers' abilities to make correct dietary judgments about a food in the context of a total daily diet (Ref. 3), which led FDA to require both quantitative and percentage declarations of nutrient Daily Values in the Nutrition Facts label in the 1993 Nutrition Labeling final rule (58 FR 2079, January 6, 1993).

Research in subsequent years, however, suggested that consumers' understanding and use of percent Daily Value may be somewhat inconsistent

(Refs. 7 and 8). Additionally, FDA has received several public comments suggesting that further research on percent Daily Values may be warranted, along with research on other modifications to the Nutrition Facts label. Suggested research on potential modifications includes research on: (1) The removal of the statements, ''Percent Daily Values are based on a 2,000 calorie diet. Your Daily Values may be higher or lower depending on your calorie needs''; (2) the removal of the table in the footnote that lists the Daily Values for total fat, saturated fat, cholesterol, sodium, total carbohydrate, and dietary fiber based on 2,000 and 2,500 calorie diets as described in § 101.9(d)(9); and (3) changes to the presentation of and amount of information provided in the Nutrition Facts label. Therefore, the FDA, as part of its effort to promote public health, proposes to use this study to explore consumer responses to various food label formats for the footnote area of the Nutrition Facts label, including those that exhibit information such as various definitions for percent Daily Value, a succinct statement about daily caloric intake, and general guidelines for high and low nutrient levels.

This study will also explore how declaring the added sugars content of foods might affect consumers' attention to and understanding of the sugars and calorie contents and other information on the Nutrition Facts label. FDA received numerous comments regarding the declaration of added sugars in response to the 2007 ANPRM even though the Agency did not ask any questions regarding the declaration of added sugars. The Agency is not aware of any existing consumer research that has examined this topic and is therefore interested in using this study to enhance understanding of how consumers would comprehend and use this new information.

In the **Federal Register** of May 23, 2011 (76 FR 29758), FDA published a 60-day notice requesting public comment on the proposed collection of information. In that notice, the Agency announced its intention to examine consumer reactions to the declaration of vitamins and minerals by weight on the Nutrition Facts label. This intention was prompted by the 2003 Institute of Medicine report that recommended declaration of weight amounts of all nutrients, including vitamins and minerals, on the food label (Ref. 9). As the report noted, public health advice on nutrient intake is often given in absolute amounts, but in the case of a nutrient such as calcium, consumers may not be able to determine the amount of calcium in a food when it is listed only as Percent Daily Values on the Nutrition Facts label. Block and Peracchio (Ref. 10) demonstrated this difficulty and the potential merits of providing consumers with easy-to-use information in helping them increase their calcium intakes. The findings by Block and Peracchio provide data on the issue we were planning to study. On the other hand, consumer evidence on the effects of declaring added sugars is lacking. Therefore, the Agency has determined that the utility of the study would be enhanced by replacing the examination of declaring amounts of vitamins and minerals by weight with an examination of declaring the amount of added sugars. This change would have minimal effects on the planned length and respondent burden of the study and would not change the study's primary focus, which remains on examining footnote options.

In the **Federal Register** of December 29, 2011 (76 FR 81949), FDA published a notice informing interested parties that the proposed collection of information had been submitted to OMB for review and clearance under the PRA and inviting the public to submit comments on the proposed study to OMB. The notice also announced FDA's plans to change the study by examining consumer reactions to the declaration of added sugars instead of the declaration of vitamins and minerals by weight. OMB received requests for an extension of time to comment on this change to the study. In response to these requests, FDA is providing an opportunity for comment on the current design of the study, including the added sugars component, by publishing a new 60-day notice describing the study as currently envisioned and inviting the public to submit comments to the Agency's docket. After considering any comments received, the Agency will resubmit the proposed collection of information to OMB. In the meantime, the Agency is withdrawing the proposed collection of information from OMB review, as announced elsewhere in this issue of the **Federal Register**.

The proposed collection of information is a controlled, randomized, experimental study. The study will use a Web-based survey, which will take about 15 minutes to complete, to collect information from 10,000 English-speaking adult members of an online consumer panel maintained by a contractor. The study will aim to recruit a sample that reflects the U.S. Census on gender, education, age, and ethnicity/race.

The study will randomly assign each of its participants to view a series of label images from a set of food labels that will be created for the study and systematically varied in the presence or absence of: (1) A definition for percent Daily Value, (2) a general guideline for ''high'' and ''low'' nutrient levels, and (3) a declaration for added sugars. A sample definition for percent Daily Value may include, for example, ''The percent Daily Value is the amount of a nutrient listed in this document that one serving of this product contributes to the daily diet.'' A sample guideline for high and low nutrient levels may include, for example, ''5 percent or less is low, and 20 percent or more is high.'' Finally, the study will also examine effects of including reference to FDA within the Nutrition Facts footnote and a succinct statement about daily caloric intake. All label images will be mock-ups resembling food labels that may be found in the marketplace. Images will show product identity (e.g., yogurt or frozen meal), but not any real or fictitious brand name.

The survey will ask its participants to view label images and answer questions about their understanding, perceptions, and reactions related to the viewed label. The study will focus on the following types of consumer reactions: (1) Judgments about a food product in terms of its nutritional attributes and overall healthfulness; (2) ability to use the Nutrition Facts label in tasks, such as identifying a product's nutrient contents and evaluating the percent Daily Values for specific nutrients; and (3) label perceptions (e.g., helpfulness and credibility). To help understand consumer reactions, the study will also collect information on participants' background, including but not limited to, use of the Nutrition Facts label and health status.

The study is part of the Agency's continuing effort to enable consumers to make informed dietary choices and construct healthful diets. Results of the study will be used primarily to enhance the Agency's understanding of how various potential modifications to the Nutrition Facts label may affect how consumers perceive a product or a label, which may in turn affect their dietary choices. Results of the study will not be used to develop population estimates.

To help design and refine the questionnaire, FDA plans to conduct cognitive interviews by screening 72 panelists in order to obtain 9 participants in the interviews. Each screening is expected to take 5 minutes (0.083 hour) and each cognitive interview is expected to take one hour. The total for cognitive interview activities is 15 hours (6 hours + 9 hours). Subsequently, we plan to conduct pretests of the questionnaire before it is administered in the study. We expect that 1,000 invitations, each taking 2 minutes (0.033 hours), will need to be sent to adult members of an online consumer panel to have 150 of them complete a 15-minute (0.25 hours) pretest. The total for the pretest activities is 71 hours (33 hours + 38 hours). For the survey, we estimate that 40,000 invitations, each taking 2 minutes (0.033 hours), will need to be sent to adult members of an online consumer panel to have 10,000 of them complete a 15-minute (0.25 hours) questionnaire. The total for the survey activities is 3,820 hours (1,320 hours + 2,500 hours). Thus, the total estimated burden is 3,906 hours.

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

TABLE 1—ESTIMATED ANNUAL REPORTING BURDEN [1]

Activity	Number of respondents	Number of responses per respondent	Total annual responses	Average burden per response	Total hours
Cognitive interview screener	72	1	72	0.083 (5 min.)	6
Cognitive interview	9	1	9	1	9
Pretest invitation	1,000	1	1,000	0.033 (2 min.)	33
Pretest	150	1	150	0.25 (15 min.)	38
Survey invitation	40,000	1	40,000	0.033 (2 min.)	1,320
Survey	10,000	1	10,000	0.25 (15 min.)	2,500
Total					3,906

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

II. 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 addresses, but we are not responsible for any subsequent changes to the Web sites after this document publishes in the **Federal Register**.)

1. Levy, A.S., S.B. Fein, and R.E. Schucker, ''Nutrition Labeling Formats: Performance and Preference,'' *Food Technology,* vol. 45, pp. 116–121, 1991.
2. Levy, A.S., S.B. Fein, and R.E. Schucker, ''More Effective Nutrition Label Formats Are Not Necessarily Preferred,'' *Journal of the American Dietetic Association,* vol. 92, pp. 1230–1234, 1992.
3. Levy, A.S., S.B. Fein, and R.E. Schucker, ''Performance Characteristics of Seven Nutrition Label Formats,'' *Journal of Public Policy and Marketing,* vol. 15, pp. 1–15, 1996.
4. Lando, A.M. and J. Labiner-Wolfe, ''Helping Consumers to Make More Healthful Food Choices: Consumer Views on Modifying Food Labels and Providing Point-of-Purchase Nutrition Information at Quick-Service Restaurants,'' *Journal of Nutrition Education and Behavior,* vol. 39, pp. 157–163, 2007.
5. U.S. Food and Drug Administration, *Calories Count: Report of the Working Group on Obesity,* 2004, available at *http://www.fda.gov/Food/LabelingNutrition/ReportsResearch/ucm081696.htm.*
6. U.S. Food and Drug Administration, ''2008 Health and Diet Survey—Preliminary Topline Frequencies (Weighted),'' 2010, available at *http://www.fda.gov/Food/ScienceResearch/ResearchAreas/ConsumerResearch/ucm193895.htm.*
7. Li, F., P.W. Miniard, and M.J. Barone, ''The Facilitating Influence of Consumer Knowledge on the Effectiveness of Daily Value Reference Information,'' *Journal of the Academy of Marketing Science,* vol. 28, pp. 425–436, 2000.
8. Levy, L., R.E. Patterson, A.R. Kristal, and S.S. Li, ''How Well Do Consumers Understand Percentage Daily Value on Food Labels?'' *American Journal of Health Promotion,* vol. 14, pp. 157–160, 2000.
9. Institute of Medicine. Dietary Reference Intakes: Guiding Principles for Nutrition Labeling and Fortification, 2003, available at *http://www.nap.edu/catalog.php?record_id=10872.*
10. Block, L.G. and L.A. Peracchio, ''The Calcium Quandary: How Consumers Use Nutrition Labels,'' *Journal of Public Policy and Marketing,* vol. 25, pp. 188–196, 2006.

Dated: May 23, 2012.

Leslie Kux,

Assistant Commissioner for Policy.

[FR Doc. 2012–13141 Filed 5–30–12; 8:45 am]

BILLING CODE 4160–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA–2011–N–0345]

Agency Information Collection Activities; Submission for Office of Management and Budget Review; Comment Request; Experimental Study on Consumer Responses to Nutrition Facts Labels With Various Footnote Formats and Declaration of Amount of Added Sugars; Withdrawal

AGENCY: Food and Drug Administration, HHS.

ACTION: Withdrawal of notice.

SUMMARY: This document withdraws a Food and Drug Administration (FDA) notice that published in the **Federal Register** of December 29, 2011 (76 FR 81948).

DATES: This notice is withdrawn on May 31, 2012.

FOR FURTHER INFORMATION CONTACT: Domini Bean, Office of Information Management, Food and Drug Administration, 1350 Piccard Dr., PI50–400T, Rockville, MD 20850, *domini.bean@fda.hhs.gov*.

SUPPLEMENTARY INFORMATION: FDA published a notice in the **Federal Register** of December 29, 2011, informing interested parties that the proposed collection of information entitled ''Experimental Study on Consumer Responses to Nutrition Facts Labels With Various Footnote Formats and Declaration of Amount of Added Sugars'' had been submitted to the Office of Management and Budget (OMB) for review and clearance under the Paperwork Reduction Act of 1995 and inviting the public to submit comments on the proposed study to OMB. The notice also announced FDA's plans to change the study by examining consumer reactions to the declaration of added sugars instead of the declaration of vitamins and minerals by weight. OMB received requests for an extension of time to comment on this change to the study. In response to these requests, FDA is providing an opportunity for comment on the current design of the study, including the added sugars component, by publishing a new 60-day notice, elsewhere in this issue of the **Federal Register**, describing the study as currently envisioned and inviting the public to submit comments to the

Agency's docket. After considering any comments received, the Agency will resubmit the proposed collection of information to OMB. Thus, FDA is withdrawing the proposed collection of information published on December 29, 2011, at this time.

Dated: May 22, 2012.

Leslie Kux,

Assistant Commissioner for Policy.

[FR Doc. 2012–13142 Filed 5–30–12; 8:45 am]

BILLING CODE 4160–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA–2012–N–0145]

Agency Information Collection Activities; Submission for Office of Management and Budget Review; Comment Request; Improving Food Safety and Defense Capacity of the State and Local Level: Review of State and Local Capacities

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

SUMMARY: The Food and Drug Administration (FDA) is announcing that a proposed collection of information has been submitted to the Office of Management and Budget (OMB) for review and clearance under the Paperwork Reduction Act of 1995.

DATES: Fax written comments on the collection of information by July 2, 2012.

ADDRESSES: 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: 202–395–7285, or emailed to *oira_submission@omb.eop.gov.* All comments should be identified with the OMB control number 0910–NEW and title ''Improving Food Safety and Defense Capacity of the State and Local Level: Review of State and Local Capacities.'' Also include the FDA docket number found in brackets in the heading of this document.

FOR FURTHER INFORMATION CONTACT: Ila S. Mizrachi, Office of Information Management, Food and Drug Administration, 1350 Piccard Dr., PI50–400B, Rockville, MD 20850, 301–796–7726, *Ila.Mizrachi@fda.hhs.gov.*

SUPPLEMENTARY INFORMATION: In compliance with 44 U.S.C. 3507, FDA has submitted the following proposed collection of information to OMB for review and clearance.

Improving Food Safety and Defense Capacity of the State and Local Level: Review of State and Local Capacities—(OMB Control Number 0910–New)

The Food Safety Modernization Act (FSMA) (Pub. L. 111–353) states in section 205(c)2 that a review must be conducted to assess the State and local government capacities to show needs for enhancement in the areas of staffing levels, laboratory capacities, and information technology systems. This mandate is referenced again in FSMA section 110, stating that a review of current food safety and food defense capabilities must be presented to Congress no later than 2 years after the date of enactment (enactment date January 4, 2011). In order to facilitate this review, a survey will be distributed to State and local health and agriculture agencies. Results of the survey will be used to analyze the gaps and trends in capacity that occurs at the State and local government levels. Results of the analyses will enable FSMA partners to develop strategies to enhance food safety and food defense capacity. In developing these strategies, FDA will be able to work with other Federal, State and local Agencies to improve and expand food safety and defense to ultimately reach a state of an integrated food safety system.

The survey will be conducted electronically, which allows FDA to conduct streamlined analysis while creating a low-burden, user-friendly environment for respondents to complete the survey. Once the results have been tabulated, a report will be generated and given to the FSMA section 110 work group to present to Congress as well as the FSMA section 205(c)1 work group to develop strategies to leverage and enhance current State and local capacities.

In the **Federal Register** of February 24, 2012 (77 FR 11132), FDA published a 60-day notice requesting public comment on the proposed collection of information. The Agency received six comments. The comments, and the Agency's responses, are discussed in the following paragraphs.

(Comment 1) FDA conducted a review of existing surveys.

(Response) Although helpful, these surveys did not fully address factors such as laboratory capacity and information technology in State and local agencies. Therefore, this survey will be used to fill the gaps of various other surveys so that FDA can meet its objective as congressionally mandated in FSMA.

(Comment 2) The proposed information collection is necessary for the proper performance of FDA's functions.

(Response) FDA believes that this comment does not address the proposed information collection.

(Comment 3) The National Association of County and City Health Officials (NACCHO) recommends FDA builds upon information gathered from existing food safety and defense assessments and surveys.

(Response) Prior to developing this survey, FDA conducted a systematic review of current and past surveys conducted by Federal, State, and local Agencies, academia, industry, and associations such as the Association of Food and Drug Officials (AFDO), the Association of State and Territorial Health Officials, and NACCHO's 2008 survey regarding budget cuts and reductions of State and local agencies. This review revealed that the current and past surveys did not contain sufficient information for FDA to establish and analyze possible gaps in the areas of food safety, food defense, laboratories, and information technology. The results of the review of current and past surveys were conveyed to an FDA working group focused on drafting a report to Congress that is specified by FSMA section 110. Under section 110, FDA has a congressionally mandated deadline to conduct a more extensive review by January 4, 2013, which will require the support of section 205(c)2. FDA was aware that NACCHO was conducting a survey but due to time restrictions, FDA could not wait for NACCHO's survey to be made public prior to developing the current survey. Also, FDA did not know the content of NACCHO's survey and how it would address the needs of obtaining information to support FSMA section 205(c)2.

(Comment 4) FDA should survey 1,400 State and local agencies at minimum instead of focusing on 1,400 State and local employees.

(Response) FDA is proposing to survey 1,400 State and local agencies. The involvement of single or multiple individuals from a single agency will be left to the discretion of the responding entity.

(Comment 5) NACCHO recommends that the assessment be designed to allow multiple employees within an agency access to the survey on multiple occasions to fully and accurately complete the survey.

(Response) FDA has an arrangement with AFDO, through a cooperative agreement, to deliver the survey, but at this time, the exact mechanism for

delivering the survey has not been established. FDA will take into consideration NACCHO's suggestion of developing a Web-based portal with log in capability to allow multiple users to log in to the same survey to increase the efficiency of completing the survey. In addition, hardcopies of the survey can be made available upon request.

(Comment 6) The assessment should be conducted on a routine basis.

(Response) FDA agrees with NACCHO in its statement that a survey, such as this one, should be conducted on a more regular basis to track and trend gaps. At this time, this survey is intended to be a one-time collection of information. FDA could consider conducting future surveys, depending on Agency resources and priorities.

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

TABLE 1—ESTIMATED ANNUAL REPORTING BURDEN [1]

Activity	Number of respondents	Number of responses per respondent	Total annual responses	Average burden per response	Total hours
Current State and local government agencies	1,400	1	1,400	1	1,400

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

This survey isslated to be a one-time survey. Through testing on six FDA employees who were former State employees, the survey development team has concluded that it should take no longer than 1 hour for the 1,400 current State and local government agencies to complete the survey. FDA is requesting this data collection burden so as not to restrict the Agency's ability to gather information on public sentiment for its proposals in its regulatory and communications programs.

Dated: May 24, 2012.

Leslie Kux,

Assistant Commissioner for Policy.

[FR Doc. 2012–13140 Filed 5–30–12; 8:45 am]

BILLING CODE 4160–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA–2012–D–0146]

Guidance for Industry on Irritable Bowel Syndrome—Clinical Evaluation of Drugs for Treatment; Availability

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

SUMMARY: The Food and Drug Administration (FDA) is announcing the availability of a guidance for industry entitled ''Irritable Bowel Syndrome—Clinical Evaluation of Drugs for Treatment.'' This guidance is intended to assist the pharmaceutical industry and investigators who are developing drugs for the treatment of irritable bowel syndrome (IBS), specifically the IBS indications for IBS with diarrhea (IBS–D) and IBS with constipation (IBS–C). The guidance describes the evolution of patient-reported outcome (PRO) measures as primary endpoints for IBS clinical trials, and sets forth provisional endpoints and trial design recommendations that sponsors may apply to IBS clinical trials as PRO measurements continue to evolve. The guidance also discusses the future development of IBS PRO instruments. This guidance finalizes the draft guidance published in March 2010.

DATES: Submit either electronic or written comments on Agency guidances at any time.

ADDRESSES: Submit written requests for single copies of this guidance to the Division of Drug Information, Center for Drug Evaluation and Research, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 51, rm. 2201, Silver Spring, MD 20993–0002. Send one self-addressed adhesive label to assist that office in processing your requests. See the **SUPPLEMENTARY INFORMATION** section for electronic access to the guidance document.

Submit electronic comments on the guidance to *http://www.regulations.gov*. Submit written comments to the Division of Dockets Management (HFA–305), Food and Drug Administration, 5630 Fishers Lane, rm. 1061, Rockville, MD 20852.

FOR FURTHER INFORMATION CONTACT: Ruyi He, Center for Drug Evaluation and Research, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 22, Rm. 5122, Silver Spring, MD 20993–0002, 301–796–0910.

SUPPLEMENTARY INFORMATION:

I. Background

FDA is announcing the availability of a guidance for industry entitled ''Irritable Bowel Syndrome—Clinical Evaluation of Drugs for Treatment.'' This guidance is intended to assist the pharmaceutical industry and investigators who are developing drugs for the treatment of IBS. This guidance applies to the IBS indications for IBS–D and IBS–C.

A well-defined and reliable PRO instrument that measures the clinically important signs and symptoms associated with each IBS subtype would be the ideal primary efficacy assessment tool in clinical trials used to support labeling claims, but at this time such an instrument is not available. We recognize that it will take some time to develop adequate instruments and that in the meantime there is a great need to develop effective therapies for patients with IBS. Therefore, until the appropriate PRO instruments have been developed, sponsors should consider the provisional endpoints and trial design recommendations set forth in the guidance.

This guidance was published as a draft guidance in March 2010. Changes made to the guidance took into consideration written and verbal comments received. In addition to editorial changes primarily for clarification, the major changes are as follows:

- The section on trial design was modified by adding a randomized withdrawal design to address the need for maintenance treatment to prevent sign or symptom recurrence.
- The section on trial endpoints was modified to note that a drug can be specifically developed to treat only one of two major signs or symptoms of IBS (abnormal defecation or abdominal pain). Demonstration of significant and clinically meaningful changes in the targeted single endpoint could serve as a basis for approval, as long as the other important symptom or sign has not worsened on treatment.
- Trial entry criteria for IBS–D were modified to allow more IBS–D patients to participate in IBS clinical trials, and the definition of a responder to treatments for IBS–D was modified accordingly.
- Definitions of a responder for abdominal pain alone, constipation, and diarrhea were added.

• The use of a daily responder analysis for IBS–D as a primary analysis was included.

This guidance is being issued consistent with FDA's good guidance practices regulation (21 CFR 10.115). The guidance represents the Agency's current thinking on the clinical evaluation of drugs for the treatment of IBS. It does not create or confer any rights for or on any person and does not operate to bind FDA or the public. An alternative approach may be used if such approach satisfies the requirements of the applicable statutes and regulations.

II. Comments

Interested persons may submit to the Division of Dockets Management (see **ADDRESSES**) either electronic or written comments regarding this document. It is only necessary to send one set of comments. Identify comments with the docket number found in brackets in the heading of this document. Received comments may be seen in the Division of Dockets Management between 9 a.m. and 4 p.m., Monday through Friday.

III. Electronic Access

Persons with access to the Internet may obtain the document at either *http://www.fda.gov/Drugs/GuidanceComplianceRegulatoryInformation/Guidances/default.htm* or *http://www.regulations.gov.*

Dated: May 23, 2012.

Leslie Kux,

Assistant Commissioner for Policy.

[FR Doc. 2012–13143 Filed 5–30–12; 8:45 am]

BILLING CODE 4160–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA–2012–N–0001]

Orthopaedic and Rehabilitation Devices Panel of the Medical Devices Advisory Committee; Amendment of Notice

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

The Food and Drug Administration (FDA) is announcing an amendment to the notice of meeting of the Orthopaedic and Rehabilitation Devices Panel of the Medical Devices Advisory Committee. This meeting was announced in the **Federal Register** of March 30, 2012 (77 FR 19293). The amendment is being made to reflect a change in the **DATES** and **ADDRESSES** portion of the document. The amendment also provides a Web address where the meeting webcast can be accessed. There are no other changes.

FOR FURTHER INFORMATION CONTACT: Avena Russell, Center for Devices and Radiological Health, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 66, rm. 1535, Silver Spring, MD 20993–0002, 301–796–3805, *Avena.Russell@fda.hhs.gov,* or please use the FDA Advisory Committee Information Line, 1–800–741–8138 (301–443–0572 in the Washington, DC area), and follow the prompts to the desired center or product area. Please call the Information Line for up-to-date information on this meeting. A notice in the **Federal Register** about last minute modifications that impact a previously announced advisory committee meeting cannot always be published quickly enough to provide timely notice. Therefore, you should always check the Agency's Web site at *http://www.fda.gov/AdvisoryCommittees/default.htm* and scroll down to the appropriate advisory committee meeting link, or call the advisory committee information line to learn about possible modifications before coming to the meeting.

SUPPLEMENTARY INFORMATION: In the **Federal Register** of March 30, 2012, FDA announced that a meeting of the Orthopaedic and Rehabilitation Devices Panel would be held on June 27 and 28, 2012. On page 19293, in the first column the **DATES** portion of the document is changed to read as follows:

The meeting will be held on June 27 and 28, 2012, from 7:30 a.m. to 7 p.m. On page 19293, in the first column, the **ADDRESSES** portion of the document is changed to read as follows:

Hilton Washington DC North/Gaithersburg, Salons A, B, C, and D, 620 Perry Pkwy., Gaithersburg, MD 20877. The hotel's telephone number is 301–977–8900.

The meeting will be webcast live and free of charge on both days and can be accessed at the following Web address:

On June 27, Day 1

http://fda.yorkcast.com/webcast/Viewer/?peid=12f84ea095b445d78e9b115f495392731d

On June 28, Day 2

http://fda.yorkcast.com/webcast/Viewer/?peid=901726ab91944b158ac705e48664921c1d

The webcast will be broadcast using Windows Media Player.

This notice is issued under the Federal Advisory Committee Act (5 U.S.C. app. 2) and 21 CFR part 14, relating to the advisory committees.

Dated: May 24, 2012.

Jill Hartzler Warner,

Acting Associate Commissioner for Special Medical Programs.

[FR Doc. 2012–13157 Filed 5–30–12; 8:45 am]

BILLING CODE 4160–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA–2012–N–0001]

Oncologic Drugs Advisory Committee; Notice of Meeting

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

This notice announces a forthcoming meeting of a public advisory committee of the Food and Drug Administration (FDA). The meeting will be open to the public.

Name of Committee: Oncologic Drugs Advisory Committee.

General Function of the Committee: To provide advice and recommendations to the Agency on FDA's regulatory issues.

Date and Time: The meeting will be held on July 24, 2012, from 8 a.m. to 5 p.m.

Location: FDA White Oak Campus, 10903 New Hampshire Ave., Building 31 Conference Center, the Great Room (rm. 1503), Silver Spring, MD 20993–0002. Information regarding special accommodations due to a disability, visitor parking, and transportation may be accessed at: *http://www.fda.gov/AdvisoryCommittees/default.htm;* under the heading ''Resources for You,'' click on ''Public Meetings at the FDA White Oak Campus.'' Please note that visitors to the White Oak Campus must enter through Building 1.

Contact Person: Caleb Briggs, Center for Drug Evaluation and Research, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 31, rm. 2417, Silver Spring, MD 20993–0002, 301–796–9001, FAX: 301–847–8533, email: *ODAC@fda.hhs.gov,* or FDA Advisory Committee Information Line, 1–800–741–8138 (301–443–0572 in the Washington, DC area), to find out further information regarding FDA advisory committee information. A notice in the **Federal Register** about last minute modifications that impact a previously announced advisory committee meeting cannot always be published quickly enough to provide timely notice. Therefore, you should always check the Agency's Web site at *http://www.fda.gov/Advisory*

Committees/default.htm and scroll down to the appropriate advisory committee meeting link, or call the advisory committee information line to learn about possible modifications before coming to the meeting.

Agenda: During the morning session, the committee will discuss supplemental new drug application (sNDA) 022059/014 with the trade name Tykerb (lapatinib) tablets, application submitted by SmithKline Beecham (Cork) Ltd, Ireland d/b/a GlaxoSmithKline. The proposed indication (use) for this product is in combination with trastuzumab for the treatment of patients with metastatic breast cancer whose tumors overexpress HER2 and who have received prior trastuzumab therapy(s).

During the afternoon session, the committee will discuss the evaluation of radiographic review in randomized clinical trials using progression-free survival (PFS) as a primary endpoint in non-hematologic malignancies. They will consider the merits of an independent audit of investigator progression assessment in a pre-specified subgroup of patients instead of an independent review of all progression assessments. The expectation is that an independent audit would streamline the conduct of clinical trials, as well as avoid missing data when no additional protocol specified progression assessments are mandated. Hematologic malignancies are excluded from this discussion because other issues (e.g., blood counts, lymph node exams, and other biomarkers) influence the assessment of PFS.

FDA intends to make background material available to the public no later than 2 business days before the meeting. If FDA is unable to post the background material on its Web site prior to the meeting, the background material will be made publicly available at the location of the advisory committee meeting, and the background material will be posted on FDA's Web site after the meeting. Background material is available at *http://www.fda.gov/AdvisoryCommittees/Calendar/default.htm.* Scroll down to the appropriate advisory committee link.

Procedure: Interested persons may present data, information, or views, orally or in writing, on issues pending before the committee. Written submissions may be made to the contact person on or before July 10, 2012. Oral presentations from the public will be scheduled between approximately 10:30 a.m. to 11 a.m., and 3:30 p.m. to 4 p.m. Those individuals interested in making formal oral presentations should notify the contact person and submit a brief statement of the general nature of the evidence or arguments they wish to present, the names and addresses of proposed participants, and an indication of the approximate time requested to make their presentation on or before June 29, 2012. Time allotted for each presentation may be limited. If the number of registrants requesting to speak is greater than can be reasonably accommodated during the scheduled open public hearing session, FDA may conduct a lottery to determine the speakers for the scheduled open public hearing session. The contact person will notify interested persons regarding their request to speak by July 2, 2012.

Persons attending FDA's advisory committee meetings are advised that the Agency is not responsible for providing access to electrical outlets.

FDA welcomes the attendance of the public at its advisory committee meetings and will make every effort to accommodate persons with physical disabilities or special needs. If you require special accommodations due to a disability, please contact Caleb Briggs at least 7 days in advance of the meeting.

FDA is committed to the orderly conduct of its advisory committee meetings. Please visit our Web site at *http://www.fda.gov/AdvisoryCommittees/AboutAdvisoryCommittees/ucm111462.htm* for procedures on public conduct during advisory committee meetings. Notice of this meeting is given under the Federal Advisory Committee Act (5 U.S.C. app. 2).

Dated: May 24, 2012.

Jill Hartzler Warner,

Acting Associate Commissioner for Special Medical Programs.

[FR Doc. 2012–13156 Filed 5–30–12; 8:45 am]

BILLING CODE 4160–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Health Resources and Services Administration

Agency Information Collection Activities: Submission for OMB Review; Comment Request

Periodically, the Health Resources and Services Administration (HRSA) publishes abstracts of information collection requests under review by the Office of Management and Budget (OMB), in compliance with the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*). To request a copy of the clearance requests submitted to OMB for review, email *paperwork@hrsa.gov* or call the HRSA Reports Clearance Office on (301) 443–1984.

The following request has been submitted to the Office of Management and Budget for review under the Paperwork Reduction Act of 1995:

Proposed Project: Rural Health Information Technology Network Development (OMB No. 0915–xxxx)—[New]

The purpose of the Rural Health Information Technology Network Development (RHITND) Program, authorized under the Public Health Service Act, Section 330A(f) (42 U.S.C. 254c(f)) as amended by Section 201, Public Law 107–251, of the Health Care Safety Net Amendments of 2002, is to improve health care and support the adoption of Health Information Technology (HIT) in rural America by providing targeted HIT support to rural health networks. HIT plays a significant role in the advancement of the Department of Health and Human Services' (HHS) priority policies to improve health care delivery. Some of these priorities include: Improving health care quality, safety, efficiency and reducing disparities, engaging patients and families in managing their health, enhancing care coordination, improving population and public health and ensuring adequate privacy and security of health information.

The intent of the RHITND Program is to support the adoption and use of electronic health records (EHR) in coordination with the ongoing HHS activities related to the Health Information Technology for Economic and Clinical Health (HITECH) Act (Pub. L. 111–5). This legislation provides HHS with the authority to establish programs to improve health care quality, safety, and efficiency through the promotion of health information technology, including EHR. For this program, performance measures were drafted to provide data useful to the program and to enable HRSA to provide aggregate program data required by Congress under the Government Performance and Results Act (GPRA) of 1993 (Pub. L. 103–62). These measures cover the principal topic areas of interest to the Office of Rural Health Policy, including: (a) Access to care; (b) the underinsured and uninsured; (c) workforce recruitment and retention; (d) sustainability; (e) health information technology; (f) network development; and (g) health related clinical measures. Several measures will be used for this program. These measures will speak to the Office's progress toward meeting the goals set.

The Agency received no comments in response to the 60-day notice published in the **Federal Register** on February 21, 2012, vol. 77, No. 34; page 9949.

The annual estimate of burden is as follows:

Instrument	Number of respondents	Responses per respondent	Total responses	Hours per response	Total burden hours
Rural Health Information Technology Network Development Program	41	1	41	3.77	154.57
Total	41	1	41	3.77	154.57

Written comments and recommendations concerning the proposed information collection should be sent within 30 days of this notice to the desk officer for HRSA, either by email to *OIRA_submission@omb.eop.gov* or by fax to 202–395–6974. Please direct all correspondence to the ''attention of the desk officer for HRSA.''

Dated: May 24, 2012.

Reva Harris,

Acting Director, Division of Policy and Information Coordination.

[FR Doc. 2012–13125 Filed 5–30–12; 8:45 am]

BILLING CODE 4165–15–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Health Resources and Services Administration

Agency Information Collection Activities: Proposed Collection: Comment Request

In compliance with the requirement for opportunity for public comment on proposed data collection projects (section 3506(c) (2) (A) of Title 44, United States Code, as amended by the Paperwork Reduction Act of 1995, Pub. L. 104–13), the Health Resources and Services Administration (HRSA) publishes periodic summaries of proposed projects being developed for submission to the Office of Management and Budget (OMB) under the Paperwork Reduction Act of 1995. To request more information on the proposed project or to obtain a copy of the data collection plans and draft instruments, email *paperwork@hrsa.gov* or call the HRSA Reports Clearance Officer at (301) 443–1984.

Comments are invited on: (a) The proposed collection of information for the proper performance of the functions of the Agency; (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: Sickle Cell Disease Treatment Demonstration Program—Quality Improvement Data Collection for the Hemoglobinopathy Learning Collaborative (OMB No. 0915–xxxx)—[New]

Background: In response to the growing need for resources devoted to sickle cell disease and other hemoglobinopathies, the United States Congress, under Section 712 of the American Jobs Creation Act of 2004 (Pub. L. 108–357), authorized a demonstration program for the prevention and treatment of sickle cell disease (SCD) to be administered through the Bureau of Primary Health Care and the Maternal and Child Health Bureau (MCHB) of the Health Resources and Services Administration (HRSA) in the U.S. Department of Health and Human Services. The program is known as the *Sickle Cell Disease Treatment Demonstration Program* (SCDTDP). The SCDTDP is designed to improve access to services for individuals with sickle cell disease, improve and expand patient and provider education, and improve and expand the continuity and coordination of service delivery for individuals with sickle cell disease and sickle cell trait.

To achieve the goals and objectives of the program, the Hemoglobinopathy Learning Collaborative (HLC) uses a process known as the Model for Improvement, a widely used approach to quality improvement (QI) in healthcare settings. The Model for Improvement utilizes a structured process that asks grantee teams to build on small tests of change in their healthcare setting, while providing monthly reporting on measurements. The proposed QI data collection and reporting system is an integral component of the HLC.

Purpose: The purpose of the proposed QI Data Collection strategy is to implement a system to monitor the progress of MCHB-funded activities in improving care and health outcomes for individuals living with sickle cell disease/trait and meeting the goals of the SCDTDP. Each grantee team will be asked to report on a core set of measures related to quality improvement for hemoglobinopathies. Through an evidence-based process, a bank of QI measures within each grantee network has been developed to assess health care utilization of the SCD population as well as several aspects of the system of care.

The QI Data Collection strategy will provide an effective and efficient mechanism to do the following: (1) Assess the services provided by grantees under the SCDTDP and monitor and drive improvement on quality measures; (2) collect, coordinate, and distribute data, best practices, and findings from network sites; (3) refine a common model protocol regarding the prevention and treatment of sickle cell disease; (4) examine/address barriers that individuals and families living with sickle cell disease face when accessing quality health care and health education; (5) evaluate the grantees' performance in meeting the objectives of the SCDTDP; and (6) provide HRSA/Congress information on the overall progress of the program.

Respondents: Grantees funded by HRSA under the SCDTDP will be the respondents for this data collection activity. Each month, SCDTDP teams will complete up to three data collection forms for 20 patients with SCD or sickle cell trait who were seen in their network that month. The Participant Profile form will collect demographic and basic health information. The Acute Care Visit and Ambulatory Care Visit forms will assess care in acute and ambulatory care settings, respectively.

All information will be collected via chart review. Data will be entered directly into a secure web-based data collection tool, called Research Electronic Data Capture (REDCap). The data entered into REDCap will be analyzed via a custom measurement generator that will calculate and export the QI measures for viewing by grantee teams and the National Coordinating Center.

The annual estimate of burden is as follows:

Questionnaires	Number of respondents	Responses per respondent	Total responses	Hours per response	Total burden hours
Participant Profile Form	9	240	2,160	.08	173
Acute Care Visit Form	9	240	2,160	.30	648
Ambulatory Care Visit Form	9	240	2,160	.30	648
Total	27		6,480		1,469

Email comments to *paperwork@hrsa.gov* or mail the HRSA Reports Clearance Officer, Room 10–29, Parklawn Building, 5600 Fishers Lane, Rockville, MD 20857. Written comments should be received within 60 days of this notice.

Dated: May 24, 2012.

Reva Harris,

Acting Director, Division of Policy and Information Coordination.

[FR Doc. 2012–13124 Filed 5–30–12; 8:45 am]

BILLING CODE 4165–15–P

DEPARTMENT OF HOMELAND SECURITY

U.S. Customs and Border Protection

Cancellation of Bond Subject to Enhanced Bonding Requirements Upon CBP's Acceptance of Qualified Superseding Bond Application

AGENCY: U.S. Customs and Border Protection, Department of Homeland Security.

ACTION: General notice.

SUMMARY: This notice announces that U.S. Customs and Border Protection (CBP) will cancel a continuous bond where the liability amount was calculated pursuant to enhanced bonding requirements (EBR bond) upon the agency's acceptance of a qualified superseding bond application. CBP will accept a qualified superseding bond application pursuant to this notice only if posted by an importer who was not a litigant in any of the *National Fisheries Institute, Inc.* v. *United States Bureau of Customs & Border Protection* (*NFI* v. *CBP*) court cases and who establishes, to CBP's satisfaction, that no contingent liability remains secured by the predecessor EBR bond and that the EBR bond does not cover entries that are subject to a pending protest. The superseding bond must also feature a limit of liability that is calculated using CBP's current bond formula and must be for the same time period covered by the EBR bond. Nothing in this Notice should be construed as applying to importers represented by the plaintiffs in the NFI litigation noted above, as their relief was granted by the Court.

DATES: A superseding bond application, including supporting documentation, must be received by CBP within 90 calendar days from the date the related preceding EBR bond becomes eligible under the conditions set forth in this Notice.

ADDRESSES: Superseding bond applications, including supporting documentation, must be sent either via mail to U.S. Customs and Border Protection, Office of Administration, Revenue Division, ATTN: Bond Team Intech 1, 6650 Telecom Drive, Indianapolis, IN 46278 or via email to *Cbp.bondquestions@dhs.gov* with a subject line of ''Superseding Bond IR#.''

FOR FURTHER INFORMATION CONTACT: Kara Welty, Revenue Division, Office of Administration, Customs and Border Protection, *kara.welty@dhs.gov,* Tel. (317) 614–4614.

SUPPLEMENTARY INFORMATION:

Background

I. Enhanced Bonding Requirements

In 2004, U.S. Customs and Border Protection (CBP) instituted a policy of reviewing the sufficiency of continuous bonds where the importer's importing activities involved merchandise subject to antidumping or countervailing duties (AD/CVD). CBP's review resulted in the imposition of enhanced bonding requirements (EBR) on importers of shrimp subject to AD/CVD. *See* 71 FR 62276, dated October 24, 2006.

II. Judicial Review

The legality of the enhanced bonding formula was challenged in the *NFI* v. *CBP* cases. *See Nat'l Fisheries Inst., Inc.* v. *CBP,* 465 F. Supp.2d 1300 (Ct. Int'l Trade 2006); *Nat'l Fisheries Inst., Inc.* v. *CBP,* 637 F. Supp.2d 1270 (Ct. Int'l Trade 2009); *Nat'l Fisheries Inst., Inc.* v. *CBP,* 714 F. Supp.2d 1231 (Ct. Int'l Trade 2010); and *Nat'l Fisheries Inst., Inc.* v. *CBP,* 751 F. Supp.2d 1318 (Ct. Int'l Trade 2010). *See http://www.cit.uscourts.gov/slip_op/Slip_op10/10-120.pdf.*

In Slip Opinion 10–120, the Court granted equitable relief to importers who were represented by the plaintiffs in *NFI* v. *CBP* (NFI Importers) and who had posted bonds calculated using the enhanced bonding formula (EBR bond). As a consequence of the court's decision, CBP cancelled NFI-Importers' EBR bonds upon their submission of replacement superseding bonds.

III. CBP Policy To Permit Cancellation of EBR Bond Upon Acceptance of Qualified Superseding Bond

CBP has now decided to implement a policy whereby the agency will accept a qualified superseding bond application that meets the conditions described in Section V of this Notice (''superseding'' as used in the sense it is used in Slip Op. 10–120, page 6) from any importer who posted an EBR bond but who was not an NFI Importer (non-NFI importer). This policy will be in effect for a period of 90 calendar days from the date that the related preceding EBR bond no longer secures any remaining sum certain or contingent debt (including, but not limited to, unliquidated entries (*see* 19 U.S.C. 1500) and matters subject to 19 U.S.C. 1592 involving actual or potential loss of revenue. This policy is not applicable to NFI importers whose relief was granted by the Court.

A Non-NFI importer wishing to take advantage of this policy must ensure that CBP's Bond Team Intech 1, within the Office of Administration's Revenue Division, receives a qualified superseding bond application and supporting documentation within this 90 day period. The superseding bond application must be accompanied by supporting documentation that includes a statement as to the date the EBR no longer secured contingent liability, as well as a statement that the EBR does not cover entries that are subject to a pending protest pursuant to 19 U.S.C. 1514 or related regulations.

If CBP accepts a qualified superseding bond, CBP will notify the non-NFI importer by providing a copy of the superseding CBP Form 301 and will cancel (''cancel'' as used in the sense it is used in Slip Op. 10–120, at pages 11–13) the related preceding EBR bond. The superseding bond will be clearly annotated to distinguish it from the preceding EBR bond. An EBR bond is not cancelled unless CBP notifies the non-NFI importer that the superseding bond has been approved. CBP will return untimely submissions as well as those that are incomplete or rejected for any other reason, promptly. CBP is not responsible for delays in a non-NFI importer's receipt of a returned application.

As CBP is not a legal party to the contractual relationship between a surety and a principal, it is noted that the agency cannot assist in matters relating to obtaining a superseding bond.

IV. EBR Bond Conditions

To qualify for cancellation and replacement by a superseding bond pursuant to this policy, an EBR bond:

- Must not secure any remaining sum certain or contingent debt (including, but not limited to, unliquidated entries (*see* 19 U.S.C. 1500) and matters subject to 19 U.S.C. 1592 involving actual or potential loss of revenue); and
- Must not cover entries that are subject to a pending protest pursuant to 19 U.S.C. 1514 or related regulations.

V. Superseding Bond Conditions

Pursuant to this policy, a qualified superseding bond posted by a non-NFI importer must meet the following conditions:

- A superseding bond must feature a limit of liability in an amount no less than the dollar amount of the continuous importer bond that CBP would have accepted had the EBR requirement not existed on the bond effective date of the EBR bond. For example, if an EBR bond features a face amount of $500,000 but would have featured a face amount of $70,000 but for the EBR requirement, then the superseding bond must feature a face amount of at least $70,000. A non-NFI importer can determine the correct amount of a superseding bond by multiplying the total of duties, taxes, and fees paid to CBP, for the twelve-month period immediately preceding the effective date of the original EBR, by ten (10) percent and rounding up as appropriate.
- A superseding bond must be for the same time period for which the related preceding EBR bond was in place. For example, if an EBR bond was in effect for a period from March 15, 2004, through April 1, 2005, then the superseding bond, despite its execution date in 2011, must secure entries for March 15, 2004, through April 1, 2005.
- A superseding bond posted pursuant to 19 CFR 113.40 must include the posting of cash or other security for each annual period that the related EBR bond was in effect.
- A superseding bond application, including supporting documentation, must be received by CBP within 90 calendar days from the date that the related preceding EBR bond no longer secures any remaining sum certain or contingent debt (including, but not limited to, unliquidated entries (*see* 19 U.S.C. 1500) and matters subject to 19 U.S.C. 1592 involving actual or potential loss of revenue).
- A superseding bond application, and supporting documentation, must be sent either via mail to U.S. Customs and Border Protection, Office of Administration, Revenue Division, ATTN: Bond Team Intech 1, 6650 Telecom Drive, Indianapolis, IN 46278 or via email to *Cbp.bondquestions@dhs.gov* with a subject line of ''Superseding Bond IR#.''

Dated: May 25, 2012.

David V. Aguilar,

Acting Commissioner, U.S. Customs and Border Protection.

[FR Doc. 2012–13179 Filed 5–30–12; 8:45 am]

BILLING CODE 9111–14–P

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

[Docket No. FR–5607–N–19]

Notice of Proposed Information Collection; Comment Request: Multifamily Contractor's/Mortgagor's Cost Breakdowns and Certifications

AGENCY: Office of the Assistant Secretary for Housing, 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:* July 30, 2012.

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, Department of Housing and Urban Development, 451 7th Street SW., Washington, DC 20410, Room 9120 or the number for the Federal Information Relay Service (1–800–877–8339).

FOR FURTHER INFORMATION CONTACT: Thomas S. Goade, Director, Technical Support, Office of Multifamily Housing Development, Department of Housing and Urban Development, 451 7th Street SW., Washington, DC 20410, telephone (202) 402–2559 (this is not a toll free number) for copies of the proposed forms and other available information.

SUPPLEMENTARY INFORMATION: The Department is submitting the proposed information collection to OMB for review, as required by the Paperwork Reduction Act of 1995 (44 U.S.C. Chapter 35, as amended).

This Notice is soliciting comments from members of the public and affected agencies concerning the proposed collection of information to: (1) Evaluate whether the proposed collection is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility; (2) evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information; (3) enhance the quality, utility, and clarity of the information to be collected; and (4) minimize the burden of the collection of information on those who are to respond; including the use of appropriate automated collection techniques or other forms of information technology, e.g., permitting electronic submission of responses.

This Notice also lists the following information:

Title of Proposal: Multifamily Contractor's/Mortgagor's Cost Breakdowns and Certifications.

OMB Control Number, if applicable: 2502–0044.

Description of the need for the information and proposed use: Contractors use the form HUD–2328 to establish a schedule of values of construction items on which the monthly advances or mortgage proceeds are based. Contractors use the form HUD–92330–A to convey actual construction costs in a standardized format of cost certification. In addition to assuring that the mortgage proceeds have not been used for purposes other than construction costs, HUD–92330–A further protects the interest of the Department by directly monitoring the accuracy of the itemized trades on form HUD–2328. This form also serves as project data to keep Field Office cost data banks and cost estimates current and accurate. HUD–92205A is used to certify the actual costs of acquisition or refinancing of projects insured under Section 223(f) program.

Agency form numbers, if applicable: HUD–2328, HUD–92330–A, and HUD–92205–A.

Estimation of the total numbers of hours needed to prepare the information collection including number of respondents, frequency of response, and hours of response: The number of burden hours is 5,840. The number of respondents is 350, the number of responses is 780, the frequency of response is on occasion, and the burden hour per responses is 5.

Status of the proposed information collection: Reinstatement with change of a previously approved collection.

Authority: The Paperwork Reduction Act of 1995, 44 U.S.C., Chapter 35, as amended.

Dated: May 24, 2012.

Ronald Y. Spraker,

Acting General Deputy Assistant Secretary for Housing-Acting General Deputy Federal Housing Commissioner.

[FR Doc. 2012–13197 Filed 5–30–12; 8:45 am]

BILLING CODE 4210–67–P

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

[FWS–R6–ES–2012–N118; FXES11130600000D2–123–FF06E00000]

Endangered and Threatened Wildlife and Plants; Recovery Permit Applications

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Notice of availability; request for comments.

SUMMARY: We, the U.S. Fish and Wildlife Service, invite the public to comment on the following applications to conduct certain activities with endangered or threatened species. The Endangered Species Act of 1973, as amended (Act), prohibits activities with endangered and threatened species unless a Federal permit allows such activity. The Act also requires that we invite public comment before issuing these permits.

DATES: To ensure consideration, please send your written comments by July 2, 2012.

ADDRESSES: You may submit comments or requests for copies or more information by any of the following methods. Alternatively, you may use one of the following methods to request hard copies or a CD–ROM of the documents. Please specify the permit you are interested in by number (e.g., Permit No. TE–123456).

- *Email: permitsR6ES@fws.gov.* Please refer to the respective permit number (e.g., Permit No. TE–123456) in the subject line of the message.
- *U.S. Mail:* Ecological Services, U.S. Fish and Wildlife Service, P.O. Box 25486–DFC, Denver, CO 80225.
- *In-Person Drop-off, Viewing, or Pickup:* Call (303) 236–4256 to make an appointment during regular business hours at 134 Union Blvd., Suite 645, Lakewood, CO 80228.

FOR FURTHER INFORMATION CONTACT: Kris Olsen, Permit Coordinator Ecological Services, (303) 236–4256 (phone); *permitsR6ES@fws.gov* (email).

SUPPLEMENTARY INFORMATION:

Background

The Act (16 U.S.C. 1531 *et seq.*) prohibits activities with endangered and threatened species unless a Federal permit allows such activity. Along with our implementing regulations in the Code of Federal Regulations (CFR) at 50 CFR 17, the Act provides for permits, and requires that we invite public comment before issuing these permits.

A permit granted by us under section 10(a)(1)(A) of the Act authorizes applicants to conduct activities with U.S. endangered or threatened species for scientific purposes, enhancement of propagation or survival, or interstate commerce (the latter only in the event that it facilitates scientific purposes or enhancement of propagation or survival). Our regulations implementing section 10(a)(1)(A) for these permits are found at 50 CFR 17.22 for endangered wildlife species, 50 CFR 17.32 for threatened wildlife species, 50 CFR 17.62 for endangered plant species, and 50 CFR 17.72 for threatened plant species.

Applications Available for Review and Comment

We invite local, State, and Federal agencies, and the public to comment on the following applications. Please refer to the appropriate permit number (e.g., Permit No. TE–123456) for the application when submitting comments.

Documents and other information the applicants have submitted with these applications are available for review, subject to the requirements of the Privacy Act (5 U.S.C. 552a) and Freedom of Information Act (5 U.S.C. 552).

Permit Application Number: 051828

Applicant: Dennis Kelly, Smithsonian National Zoological Park, Front Royal, Virginia.

The applicant requests renewal of an existing permit to take (propagate) captive-bred black-footed ferrets (*Mustela nigripes*) in Virginia, for the purpose of enhancing the species' survival.

Permit Application Number: 054317

Applicant: Glen Gantz, InterWest Wildlife & Ecological Services, Inc., Richmond, Utah.

The applicant requests a permit to take (harass by survey) Southwestern willow flycatcher (*Empidonax traillii extimus*) in conjunction with surveys and population monitoring activities in Utah for the purpose of enhancing the species' survival.

Permit Application Number: TE–067729

Applicant: Keith Gido, Kansas State University, Division of Biology, Manhattan, Kansas.

The applicant requests amendment of an existing permit to take (capture, handle, fin clip, and release) the Loach minnow (*Tiaroga cobitis*) and Spikedace (*Meda fulgida*), in conjunction with surveys and population monitoring activities throughout the range of each species in New Mexico, for the purpose of enhancing the species' survival.

National Environmental Policy Act

In compliance with (42 U.S.C. 4321 *et seq.),* we have made an initial determination that the proposed activities in these permits are categorically excluded from the requirement to prepare an environmental assessment or environmental impact statement (516 DM 6 Appendix 1, 1.4C(1)).

Public Availability of Comments

All comments and materials we receive in response to this request will be available for public inspection, by appointment, during normal business hours at the address listed in the **ADDRESSES** section of this notice.

Before including your address, phone number, email address, or other personal identifying information in your comment, you should be aware that your entire comment—including your personal identifying information—may be made publicly available at any time. While you can ask us in your comment to withhold your personal identifying information from public review, we cannot guarantee that we will be able to do so.

Authority: We provide this notice under section 10 of the Act (16 U.S.C. 1531 et seq.)

Dated: May 18, 2012.

Michael G. Thabault,

Acting Regional Director, Mountain-Prairie Region.

[FR Doc. 2012–13155 Filed 5–30–12; 8:45 am]

BILLING CODE 4310–55–P

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

[FWS–R5–R–2012–N061; BAC–4311–K9–S3]

Prime Hook National Wildlife Refuge, Sussex County, DE; Draft Comprehensive Conservation Plan and Environmental Impact Statement

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Notice of availability; request for comments.

SUMMARY: We, the U.S. Fish and Wildlife Service (Service), announce the availability of a draft comprehensive conservation plan and draft environmental impact statement (draft CCP/EIS) for Prime Hook National Wildlife Refuge (NWR), located in Sussex County, Delaware, for public review and comment. The draft CCP/EIS describes our proposal for managing the refuge for the next 15 years following the approval of the final CCP. Also available for public review and comment are: (1) The draft findings of appropriateness and draft compatibility determinations for uses to be allowed upon initial completion of the plan if Service-preferred alternative B is selected, (2) the draft habitat management plan, and (3) the draft hunting plan. These are included as appendix E, appendix B, and appendix C, respectively, in the draft CCP/EIS.

DATES: To ensure consideration, please send your comments no later than August 6, 2012. We will announce upcoming public meetings in local news media, via our project mailing list, and on our regional planning Web site: *http://www.fws.gov/northeast/planning/Prime%20Hook/ccphome.html.*

ADDRESSES: You may submit comments or requests for copies or more information by any of the following methods. You may request hard copies or a CD–ROM of the documents.

Email: northeastplanning@fws.gov. Please include ''Prime Hook NWR Draft CCP'' in the subject line of the message.

Fax: Attn: Thomas Bonetti, 413–253–8468.

U.S. Mail: Thomas Bonetti, U.S. Fish and Wildlife Service, 300 Westgate Center Drive, Hadley, MA 01035.

In-Person Drop-off, Viewing, or Pickup: Call 302–684–8419 to make an appointment (necessary for view/pickup only) during regular business hours at 11978 Turkle Pond Road, Milton, DE 19968. For more information on locations for viewing or obtaining documents, see ''Public Availability of Documents'' under **SUPPLEMENTARY INFORMATION**.

FOR FURTHER INFORMATION CONTACT: Michael Stroeh, Project Leader, 302–653–9345, or Tom Bonetti, Planning Team Leader, 413–253–8307 (phone); *northeastplanning@fws.gov* (email).

SUPPLEMENTARY INFORMATION:

Introduction

With this notice, we continue the CCP process for Prime Hook NWR. We started this process through a notice in the **Federal Register** (70 FR 60365; October 17, 2005) announcing that we were preparing a CCP and environmental assessment (EA). On May 9, 2011, we issued a second notice in the **Federal Register** (76 FR 26751) announcing we were preparing an EIS in conjunction with the CCP.

In 1963, Prime Hook NWR was established under the authority of the Migratory Bird Conservation Act (16 U.S.C. 715–715r) for use as an inviolate sanctuary, or any other management purpose, expressly for migratory birds. Farms and residences were once present on portions of what is now the refuge. Established primarily to preserve coastal wetlands as wintering and breeding habitat for migratory waterfowl, Prime Hook NWR's 10,133 acres stretch along the west shore of Delaware Bay, 22 miles southeast of Dover, Delaware. Eighty percent of the refuge's vegetation cover types is characterized by tidal and freshwater creek drainages that discharge into the Delaware Bay and associated coastal marshes. The remaining 20 percent is composed of upland habitats. The land uses near the refuge are intensive agricultural and developed residential.

Background

The CCP Process

The National Wildlife Refuge System Administration Act of 1966 (16 U.S.C. 668dd–668ee) (Refuge Administration Act), as amended by the National Wildlife Refuge System Improvement Act of 1997, requires us to develop a CCP for each national wildlife refuge. The purpose for developing a CCP is to provide refuge managers with a 15-year plan 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 our policies. In addition to outlining broad management direction on conserving wildlife and their habitats, CCPs identify wildlife-dependent recreational opportunities available to the public, including opportunities for hunting, fishing, wildlife observation and photography, and environmental education and interpretation. We will review and update the CCP at least every 15 years in accordance with the Refuge Administration Act.

Public Outreach

We started pre-planning for the Prime Hook NWR CCP in September 2004. In June 2005, we distributed our first newsletter and press release announcing our intent to prepare a CCP for the refuge. In November 2005, we had a formal public scoping period. The purpose of the public scoping period was to solicit comments from the community and other interested parties on the issues and impacts that should be evaluated in the draft CCP/EA. To help solicit public comments, we held three public meetings in Milton, Dover, and Lewes, DE, which 110 members of the public attended. Throughout the rest of the planning process, we have conducted additional outreach by participating in community meetings, events, and other public forums, and by requesting public input on managing the refuge and its programs.

CCP Alternatives We Are Considering

During the public scoping process, we, other governmental partners, and the public, raised several issues. To address these issues, we developed and evaluated three alternatives in the draft CCP/EIS. Here we present a brief summary of each of the alternatives; a full description of each alternative is in the draft CCP/EIS.

Alternative A (Current Management)

Alternative A (current management) satisfies the National Environmental Policy Act (40 CFR 1506.6(b)) requirement of a ''No Action'' alternative, which we define as ''continuing current management.'' It primarily describes our existing management priorities and activities, and involves no active management of wetlands due to recent extensive changes along the refuge shoreline; it also involves no active forest management and no agricultural management of upland fields. It serves as a baseline for comparing and contrasting alternatives B and C. It would maintain our current public use programs. Under alternative A, our biological program would continue its present priorities: Conserving and enhancing waterfowl and shorebird habitats, maintaining habitat for the Delmarva fox squirrel, cooperating with State partners in monitoring bald eagles and fox squirrels, protecting bald eagle and osprey active nest sites from human disturbance on refuge lands, using prescribed fire to reduce fuel hazards near beach communities, simulating natural fire processes on refuge habitats, and conducting wildlife and habitat monitoring. We would continue to offer hunting and fishing opportunities on refuge lands, and respond to requests for interpretive and school programs.

Alternative B (Service-Preferred)

This alternative is the Service-preferred alternative. It combines the actions we believe would most effectively achieve the refuge's purposes, vision, and goals and responds to the issues raised during the scoping period. Under alternative B, the refuge would actively manage habitat to mimic natural processes and restore habitat quality. At the same time, the refuge would strategically reduce management actions that are contrary to the directions of the biological integrity, diversity, and environmental health policy, such as artificial maintenance of extensive freshwater wetlands that are vulnerable to sea level rise. Alternative B would enhance visitor services through a proposed expansion of the hunting program with greater administrative efficiency, new hiking trails, and expanded fishing opportunities and environmental education programs. Under alternative B, we would not reinstate the cooperative farming program; instead, we would propose to restore areas previously farmed to native forest habitat.

Alternative C (Historic Habitat Management)

Alternative C emphasizes a return to habitat management programs that were conducted on the refuge through most of its existence, but were stopped in recent years for a variety of reasons. The historic habitat management programs conducted for the benefit of migratory birds include the use of cooperative farming in upland refuge fields and management of freshwater wetland impoundments. Under this alternative, we would conduct necessary infrastructure and duneline enhancements to re-establish management of freshwater impoundments. In contrast to alternatives A or B, alternative C less effectively addresses the refuge's purposes, mission, and Service policies, as it is less likely to be naturally sustainable, will require perpetual intervention to sustain dunes in their former location, and will be more vulnerable to coastal storm events that may overtop an artificially maintained barrier and introduce salt water into a managed freshwater marsh system. Upland fields previously enrolled in the cooperative farming program would once again be managed through farming practices with the cooperation of local farmers. Alternative C would expand opportunities for hunting and have a greater emphasis on public outreach and education. Compared to alternative B, however, alternative C would decrease the amount of hunting areas and opportunities. Fishing, wildlife observation, and wildlife photography would be similar to those in alternative A. Under alternative C, we would further enhance local community outreach and partnerships, continue to support a friends group, and continue to provide valuable volunteer experiences. We would also promote research and the development of applied management practices through local universities to sustain and enhance natural composition, patterns, and processes within their range on the Delmarva Peninsula.

Public Availability of Documents

In addition to any methods in **ADDRESSES**, you can view or obtain documents on the refuge Web site: *http://www.fws.gov/northeast/planning/Prime%20Hook/ccphome.html.*

Submitting Comments/Issues for Comment

We are seeking substantive comments, particularly on the following issues:

- Issue 1—Climate change, sea-level rise, and marshes;
- Issue 2—Mosquito control;
- Issue 3—Cooperative farming;
- Issue 4—Hunting; and
- Issue 5—Nuisance species

We consider comments substantive if they:

- Question, with reasonable basis, the accuracy of the information in the document;
- Question, with reasonable basis, the adequacy of the EIS;
- Present reasonable alternatives other than those presented in the EIS; and/or
- Provide new or additional information relevant to the EIS.

Next Steps

After this comment period ends, we will analyze the comments and address them in the form of a final CCP/EIS.

Public Availability of Comments

Before including your address, phone number, email address, or other personal identifying information in your comment, you should be aware that your entire comment—including your personal identifying information—may be made publicly available at any time. While you can ask us in your comment to withhold your personal identifying information from public review, we cannot guarantee that we will be able to do so.

Dated: May 2, 2012.

Henry Chang,

Acting Regional Director, Northeast Region.

[FR Doc. 2012–13074 Filed 5–30–12; 8:45 am]

BILLING CODE 4310–55–P

DEPARTMENT OF THE INTERIOR

Bureau of Indian Affairs

Notice of Intent To Prepare an Environmental Impact Statement for the Proposed Fee-to-Trust Transfer of Property and Subsequent Development of a Resort/Hotel and Ancillary Facilities in the City of Taunton, MA and Tribal Government Facilities in the Town of Mashpee, MA by the Mashpee Wampanoag Tribe

AGENCY: Bureau of Indian Affairs, Interior.

ACTION: Notice.

SUMMARY: This notice advises the public that the Bureau of Indian Affairs (BIA) intends to gather the information necessary for preparing an environmental impact statement (EIS) for the conveyance into trust of 170.1 acres of land currently held by the Mashpee Wampanoag Tribe (Tribe) in the Town of Mashpee, Massachusetts, and 146.39 acres of land in the City of Taunton. The purpose of the proposed action is to help provide for the economic development of the Tribe and to create a tribal land base. The Tribe is currently federally recognized but does not currently have a federally protected reservation or have land that is held in trust for the Tribe by the United States. This notice also announces public scoping meetings to identify potential issues, alternatives, and content for inclusion in the EIS.

DATES: Written comments on the scope of the EIS or implementation of the proposal must arrive by July 2, 2012. The public scoping meetings will be held June 20, 2012, in Taunton, Massachusetts, and June 21, 2012, in Mashpee, Massachusetts. Both meetings will begin at 6 p.m. and last until the last public comment is received.

ADDRESSES: You may mail, hand deliver, or telefax written comments to Franklin Keel, Regional Director, Eastern Regional Office, Bureau of Indian Affairs, 545 Marriott Drive, Suite 700, Nashville, Tennessee 37214, Telefax (615) 564–6701. Please include your name, return address and the caption specifying ''Scoping Comments for Proposed Mashpee Wampanoag Tribe Property Trust and Development'' on the first page of your written comments. The public scoping meetings will be held at the Taunton High School, 50 William Street, Taunton, Massachusetts and Mashpee High School, 500 Old Barnstable Road, Mashpee, Massachusetts.

FOR FURTHER INFORMATION CONTACT: Chet McGhee, Regional Environmental Scientist, Eastern Regional Office, Bureau of Indian Affairs, 545 Marriott Drive, Suite 700, Nashville, Tennessee 37214; telephone: (615) 564–6500.

SUPPLEMENTARY INFORMATION: The Tribe proposes that 146.39 acres in the City of Taunton, Massachusetts, be taken into trust and for the development of a casino, hotel, parking, and other facilities supporting the casino. The Tribe also proposes that 170.1 acres in the Town of Mashpee, Massachusetts, be taken into trust, for the continuation of its current uses of Tribal government and housing. The property in the City of Taunton is located within the current site of the Liberty & Union Industrial Park, generally bounded on the south by Route 140, on the west by Route 24, on the north by Middleborough Avenue, and on the east by Stevens Street. The proposed action is to develop a Class III gaming facility including a casino, parking structures, hotels, restaurants, retail, and a waterpark. The site is proposed to be accessible from Route 140 via Stevens Street. The property in the Town of Mashpee is located across eleven parcels totaling approximately 170.1 acres, including areas currently in use by the Tribe as council offices, a museum, and a burial ground. Proposed actions for the parcels include preserving these educational, recreational, and cultural sites as well as vacant land areas, in addition to developing some vacant land for tribal housing and building a permanent Tribal Government Center at the current site of Tribal Council Offices.

Areas of environmental concern so far identified that the EIS will address include traffic, air quality, wetland resources, cultural and historic resources, water supply, wastewater, storm water, land impacts, rare species and wildlife, environmental justice, soils and geology, land use, community character, and safety. The range of issues addressed in the EIS may also be expanded based on comments received in response to this notice and at the public scoping meeting.

Public Comment Availability

Comments, including names and addresses of respondents, will be available for public review at all of the mailing addresses shown in the **ADDRESSES** section (except those for the public meetings) during business hours, 8 a.m. to 4:30 p.m., Monday through Friday, except holidays. Before including your address, phone number, email address, or other personal identifying information in your comment, you should be aware that your entire comment—including your personal identifying information—may be made publicly available at any time. While you can ask us in your comment to withhold your personal identifying information from public review, we cannot guarantee that we will be able to do so.

Authority

This notice is published in accordance with section 1503.1 of the Council of Environmental Quality regulations (40 CFR parts 1500 through 1508) and Sec. 46.305 of the Department of Interior Regulations (43 CFR part 46) implementing the procedural requirements of the National Environmental Policy Act of 1969, as amended (42 U.S.C. 4321 *et seq.*), and is in the exercise of authority delegated to the Assistant Secretary—Indian Affairs by part 209 of the Department Manual.

Dated: May 24, 2012.

Donald E. Laverdure,

Acting Assistant Secretary—Indian Affairs.

[FR Doc. 2012–13159 Filed 5–30–12; 8:45 am]

BILLING CODE 4310–W7–P

DEPARTMENT OF THE INTERIOR

National Park Service

[NPS–WASO–NRNHL–0512–10297; 2200–3200–665]

National Register of Historic Places; Notification of Pending Nominations and Related Actions

Nominations for the following properties being considered for listing or related actions in the National Register were received by the National Park Service before May 5, 2012. Pursuant to section 60.13 of 36 CFR part 60, written comments are being accepted concerning the significance of the nominated properties under the National Register criteria for evaluation. Comments may be forwarded by United States Postal Service, to the National Register of Historic Places, National Park Service, 1849 C St. NW., MS 2280, Washington, DC 20240; by all other carriers, National Register of Historic Places, National Park Service, 1201 Eye St. NW., 8th floor, Washington, DC 20005; or by fax, 202–371–6447. Written or faxed comments should be submitted by June 15, 2012. Before including your address, phone number, email address, or other personal identifying information in your comment, you should be aware that your entire comment—including your personal identifying information—may be made publicly available at any time. While you can ask us in your comment to withhold your personal identifying information from public review, we cannot guarantee that we will be able to do so.

Alexandra Lord,

Acting Chief, National Register of Historic Places/National Historic Landmarks Program.

INDIANA

La Porte County

Garwood, John and Cynthia, Farmstead, 5600 Small Rd., La Porte, 12000334

Lake County

Indi—Illi Park Historic District, (Historic Residential Suburbs in the United States, 1830–1960 MPS) Roughly bounded by Locust & 169th Sts., Hohman & State Line Aves., Hammond, 12000335

Marion County

Watson Park Historic District, Roughly bounded by 38th St., Watson Rd., Birchwood, Fairfield, & Central Aves., Indianapolis, 12000336

Marshall County

Boggs, Lewis and Sarah, House, 9564 14th Rd., Argos, 12000337

Hoham—Klinghammer—Weckerle House and Brewery Site, 1715 Lake Ave., Plymouth, 12000338

Pulaski County

Monterey Bandstand, Walnut St., Monterey, 12000339

MASSACHUSETTS

Norfolk County

Sullivan's Corner Historic District, Roughly jct. of Main, Needham, & Seekonk Sts., Norfolk, 12000340

NEW YORK

Erie County

Automobile Club of Buffalo, 10405 Main St., Clarence, 12000341

Monroe County

Church of Saints Peter and Paul Complex, 720 & 736 W. Main, & 681 Brown Sts., Rochester, 12000342

Payne, William A., House, 505 Elmgrove Rd., Greece, 12000343

Ulster County

Ellenville Downtown Historic District, Canal, Center, Liberty, Main, & Market Sts., Ellenville, 12000344

NORTH CAROLINA

Durham County

Scott and Roberts Dry Cleaning Plant, Office, and Store, 733 Foster St., Durham, 12000345

OKLAHOMA

Garfield County

Clay Hall, 311–325 Lakeview Dr., Enid, 12000346

Oklahoma County

Osler Building, 1200 N. Walker Ave., Oklahoma City, 12000347

Tulsa County

Whittier Square Historic District, (Route 66 and Associated Resources in Oklahoma AD MPS) Roughly between Lewis, & Zunis Aves., E. 1st St., & I–244, Tulsa, 12000348

Wagoner County

Jamison Cemetery, 2 mi. S. on OK 16 & 2 mi. W. on Cty. Rd. E0820, Okay, 12000349

TEXAS

Dallas County

Dallas Coffin Company, 1325 S. Lamar, Dallas, 12000350

Harris County

Mellinger, Marguerite Meachum & John S., House, 3452 Del Monte Dr., Houston, 12000351

Somervell County

Oakdale Park, 1019 NE. Barnard St., Glen Rose, 12000352

WISCONSIN

Columbia County

Old Indian Agency House (Boundary Increase), 1490 Agency House Rd., Portage, 12000353

Milwaukee County

Wauwatosa Avenue Residential Historic District, 1809–1845 (odd only) & 1907 to 2242 Wauwatosa, & 7606 & 7624 Stickney Aves., Wauwatosa, 12000354

A request for removal has been made for the following resources:

INDIANA

Knox County

Rose Hill Farmstead, Co. Rd. ce10s, 0.25 mi. N of jct. with Old Wheatland Rd., Vincennes, 95000202

Morgan County

Hite—Finney House, 183 N. Jefferson St., Martinsville, 95001532

Wayne County

Richmond Gas Company Building, 100 E. Main St., Richmond, 81000023

[FR Doc. 2012–13135 Filed 5–30–12; 8:45 am]

BILLING CODE 4312–51–P

DEPARTMENT OF JUSTICE

[OMB Number 1105–0084]

Agency Information Collection Activities: Proposed Collection; Comments Requested; Application for Approval as a Nonprofit Budget and Credit Counseling Agency

ACTION: 60-Day Notice of Application Under Review.

The Department of Justice, Executive Office for United States Trustees, will be submitting the following application to the Office of Management and Budget (OMB) for review and clearance in accordance with the Paperwork Reduction Act of 1995. The application is published to obtain comments from the public and affected agencies. Comments are encouraged and will be accepted for 60 days until July 30, 2012.

All comments and suggestions, or questions regarding additional information, to include obtaining a copy of the proposed application with instructions, should be directed to Wendy Tien, Deputy Assistant Director, at the Executive Office for United States Trustees, Department of Justice, 20 Massachusetts Avenue NW, Suite 8000, Washington, DC 20530, or by facsimile at (202) 305–8536.

Written comments and suggestions from the public and affected agencies concerning the collection of information are encouraged. Comments should address one or more of the following four points:

1. Evaluate whether the application 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 collection of information, including the validity of the methodology and assumptions used;
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, electronic, mechanical, or other technological collection techniques or other forms of information technology, e.g., permitting electronic submission of responses.

Overview of the Information

Type of information collection	Application form.
The title of the form/collection	Application for Approval as a Nonprofit Budget and Credit Counseling Agency.
The agency form number, if any, and the applicable component of the department sponsoring the collection.	No form number. Executive Office for United States Trustees, Department of Justice.
Affected public who will be asked or required to respond, as well as a brief abstract.	Primary: Agencies who wish to offer credit counseling services. Other: None. Congress passed a bankruptcy law that requires any individual who wishes to file for bankruptcy to, within 180 days of filing for bankruptcy relief, first obtain credit counseling from a nonprofit budget and credit counseling agency that has been approved by the United States Trustee.
An estimate of the total number of respondents and the amount of time estimated for an average respondent to respond/reply.	It is estimated that 300 respondents will complete the application in approximately ten (10) hours.
An estimate of the total public burden (in hours) associated with the collection.	The estimated total annual public burden associated with this application is 3,000 hours.

If additional information is required, contact: Jerri Murray, Department Clearance Officer, United States Department of Justice, Justice Management Division, Policy and Planning Staff, Two Constitution Square, 145 N Street NE., Room 2E–508, Washington, DC 20530.

Jerri Murray,

Department Clearance Officer, PRA, United States Department of Justice.

[FR Doc. 2012–13163 Filed 5–30–12; 8:45 am]

BILLING CODE 4410–40–P

DEPARTMENT OF JUSTICE

Notice of Lodging of Consent Decree Under the Clean Air Act and the Emergency Planning and Community Right to Know Act.

Notice is hereby given that on May 23, 2012, a proposed Consent Decree (''Decree'') in *United States* v. *BP Products North America,* Civil Action No. 2:12–cv–207, was lodged with the United States District Court for the Northern District of Indiana.

The settlement relates to BP Products North America Inc.'s (''BP Products'') petroleum refinery located in Whiting, Indiana (the ''Whiting Refinery'')

The proposed Consent Decree resolves claims of the United States under the Clean Air Act and under the Emergency Planning and Community Right to Know Act related to the Whiting Refinery. Under the proposed Consent Decree, BP Products will pay a civil penalty in the amount of $7.2 million to the United States and $800,000 to the State of Indiana. In addition, the Consent Decree imposes emission limits on several pollutants at multiple units, requires the installation of flare gas recovery systems and improved flaring efficiency, and enhanced controls for leak detection and repair and benzene-containing wastewater. The Consent Decree includes a supplemental environmental project requiring BP to install four monitoring stations at the boundary of the property, and to provide the monitoring data to a publicly available Web site on a weekly basis. The Consent Decree also requires BP Products to spend $9.5 million on energy efficiency projects at the Whiting Refinery to reduce greenhouse gas emissions.

The Department of Justice will receive for a period of thirty (30) days from the date of this publication comments relating to the Decree. Comments should be addressed to the Assistant Attorney General, Environmental and Natural Resources Division, and either emailed to *pubcomment-ees.enrd@usdoj.gov* or mailed to P.O. Box 7611, U.S. Department of Justice, Washington, DC 20044–7611, and should refer to *United States* v. *BP Products North America, Inc.,* Civil Action No. 2:12–207, DJ Ref. 90–5–2–1–09244.

During the public comment period, the Consent Decree also may be examined on the following Department of Justice Web site: *http://www.usdoj.gov/enrd/Consent_Decrees.html.* A copy of the Decree may also be obtained by mail from the Consent Decree Library, P.O. Box 7611, U.S. Department of Justice, Washington, DC 20044–7611 or by faxing or emailing a request to ''Consent Decree Copy'' (*EESCDCopy.ENRD@usdoj.gov*), fax no. (202) 514–0097, phone confirmation number (202) 514–5271. If requesting a copy from the Consent Decree Library, please enclose a check in the amount of $81.00 (25 cents per page reproduction cost) payable to the U.S. Treasury or, if by email or fax, forward a check in that amount to the Consent Decree Library at the address given above. If requesting a copy exclusive of exhibits, please enclose a check in the amount of $35.00.

Robert Brook,

Assistant Chief, Environmental Enforcement Section, Environment and Natural Resources Division.

[FR Doc. 2012–13094 Filed 5–30–12; 8:45 am]

BILLING CODE 4410–15–P

DEPARTMENT OF JUSTICE

Bureau of Alcohol, Tobacco, Firearms and Explosives

[OMB Number 1140–0002]

Agency Information Collection Activities: Proposed Collection; Comments Requested; Application for Restoration of Firearms Privileges

ACTION: 30-Day Notice of Information Collection Under Review.

The Department of Justice (DOJ), Bureau of Alcohol, Tobacco, Firearms and Explosives (ATF) will be submitting the following information collection request to the Office of Management and Budget (OMB) for review and approval in accordance with the Paperwork Reduction Act of 1995. The proposed information collection is published to obtain comments from the public and affected agencies. This proposed information collection was previously published in the **Federal Register** Volume 77, Number 58, page 17502 on March 26, 2012, allowing for a 60-day comment period.

The purpose of this notice is to allow for an additional 30 days for public comment until July 2, 2012. This process is conducted in accordance with 5 CFR 1320.10.

Written comments concerning this information collection should be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, Attn: DOJ Desk Officer. The best way to ensure your comments are received is to email them to *oira_submission@omb.eop.gov* or fax them to 202–395–7285. All comments should reference the eight digit OMB number or the title of the collection. If you have questions concerning the collection, contact Stuart Lowrey, Chief, Firearms Operations Division at *fipb-informationcollection@atf.gov.*

Written comments and suggestions from the public and affected agencies concerning the proposed collection of information are encouraged. Your comments should address one or more of the following four points:

—Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;

—Evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;

—Enhance the quality, utility, and clarity of the information to be collected; and

—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.

Summary of Collection

(1) *Type of Information Collection:* Extension of a currently approved collection.

(2) *Title of the Form/Collection:* Application For Restoration of Firearms Privileges.

(3) *Agency form number, if any, and the applicable component of the Department of Justice sponsoring the collection:* Form Number: ATF F 3210.1. Bureau of Alcohol, Tobacco, Firearms and Explosives.

(4) *Affected public who will be asked or required to respond, as well as a brief abstract. Primary:* Individuals or households. Other: Business or other for-profit.

Need for Collection

Certain categories of persons are prohibited from possessing firearms. ATF F 3210.1, Application For Restoration of Firearms Privileges is the basis for ATF investigating the merits of an applicant to have his/her rights restored.

(5) *An estimate of the total number of respondents and the amount of time estimated for an average respondent to respond:* It is estimated that 250 respondents will complete the form within approximately 30 minutes.

(6) *An estimate of the total burden (in hours) associated with the collection:* There are an estimated 125 annual total burden hours associated with this collection.

If additional information is required contact: Jerri Murray, Department Clearance Officer, Policy and Planning Staff, Justice Management Division, Department of Justice, Two Constitution Square, Room 2E–508, 145 N Street NE., Washington, DC 20530.

Jerri Murray,

Department Clearance Officer, PRA, United States Department of Justice.

[FR Doc. 2012–13165 Filed 5–30–12; 8:45 am]

BILLING CODE 4810–FY–P

DEPARTMENT OF JUSTICE

Bureau of Alcohol, Tobacco, Firearms and Explosives

[OMB Number 1140–0039]

Agency Information Collection Activities: Proposed collection; Comments Requested; Federal Firearms Licensee Firearms Inventory Theft/Loss Report

ACTION: 30-Day Notice of Information Collection Under Review:

The Department of Justice (DOJ), Bureau of Alcohol, Tobacco, Firearms and Explosives (ATF) has submitted the following information collection request to the Office of Management and Budget (OMB) for review and approval in accordance with the Paperwork Reduction Act of 1995. The proposed information collection is published to obtain comments from the public and affected agencies. This proposed information collection was previously published in the **Federal Register** Volume 77, Number 58, page 17503 on March 26, 2012, allowing for a 60-day comment period.

The purpose of this notice is to allow for an additional 30 days for public comment until July 2, 2012. This process is conducted in accordance with 5 CFR 1320.10.

Written comments concerning this information collection should be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, Attn: DOJ Desk Officer. The best way to ensure your comments are received is to email them to *oira_submission@omb.eop.gov* or fax them to 202–395–7285. All comments should reference the eight digit OMB number or the title of the collection.

Written comments and suggestions from the public and affected agencies concerning the proposed collection of information are encouraged. Your comments should address one or more of the following four points:

—Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;

—Evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;

—Enhance the quality, utility, and clarity of the information to be collected; and

—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.

Summary of Collection

(1) *Type of Information Collection:* Extension of a currently approved collection.

(2) *Title of the Form/Collection:* Federal Firearms Licensee Firearms Inventory Theft/Loss Report.

(3) *Agency form number, if any, and the applicable component of the Department of Justice sponsoring the collection: Form Number:* ATF F 3310.11. Bureau of Alcohol, Tobacco, Firearms and Explosives.

(4) *Affected public who will be asked or required to respond, as well as a brief abstract: Primary:* Individuals or households. *Other:* Business or other for-profit.

Need for Collection

Authorization of this form is requested as the Violent Crime Control and Law Enforcement Act requires Federal firearms licensees to report to the Bureau of Alcohol, Tobacco, Firearms and Explosives and to the appropriate local authorities any theft or loss of a firearm from the licensee's inventory or collection within a specific time frame after the theft or loss is discovered.

(5) *An estimate of the total number of respondents and the amount of time estimated for an average respondent to respond:* It is estimated that 4,000 respondents will complete the form within approximately 24 minutes.

(6) *An estimate of the total burden (in hours) associated with the collection:* There are an estimated 1,600 total burden hours associated with this collection.

If additional information is required contact: Jerri Murray, Department Clearance Officer, Policy and Planning Staff, Justice Management Division, Department of Justice, Two Constitution Square, 145 N Street NE., Room 2E–508, Washington, DC 20530.

Jerri Murray,

Department Clearance Officer, PRA, United States Department of Justice.

[FR Doc. 2012–13166 Filed 5–30–12; 8:45 am]

BILLING CODE 4810–FY–P

DEPARTMENT OF JUSTICE

Bureau of Alcohol, Tobacco, Firearms and Explosives

[OMB Number 1140–0071]

Agency Information Collection Activities:

Proposed collection; comments requested;

Notification to Fire Safety Authority of Storage of Explosive Materials

ACTION: 30-Day Notice of Information Collection Under Review:

The Department of Justice (DOJ), Bureau of Alcohol, Tobacco, Firearms and Explosives (ATF) will be submitting the following information collection request to the Office of Management and Budget (OMB) for review and approval in accordance with the Paperwork Reduction Act of 1995. The proposed information collection is published to obtain comments from the public and affected agencies. This proposed information collection was previously published in the **Federal Register** Volume 77, Number 58, page 17504 on March 26, 2012, allowing for a 60-day comment period.

The purpose of this notice is to allow for an additional 30 days for public comment until July 2, 2012. This process is conducted in accordance with 5 CFR 1320.10.

Written comments concerning this information collection should be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, Attn: DOJ Desk Officer. The best way to ensure your comments are received is to email them to *oira_submission@omb.eop.gov* or fax them to 202–395–7285. All comments should reference the eight digit OMB number or the title of the collection. If you have questions concerning the collection, contact William Miller, Chief, Explosives Industry Programs Branch at *eipb@atf.gov.*

Written comments and suggestions from the public and affected agencies concerning the proposed collection of information are encouraged. Your comments should address one or more of the following four points:

—Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;
—Evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;
—Enhance the quality, utility, and clarity of the information to be collected; and
—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.

Summary of Collection

(1) *Type of Information Collection:* Extension of a currently approved collection.

(2) *Title of the Form/Collection:* Notification to Fire Safety Authority of Storage of Explosive Materials.

(3) *Agency form number, if any, and the applicable component of the Department of Justice sponsoring the collection: Form Number:* None. Bureau of Alcohol, Tobacco, Firearms and Explosives.

(4) *Affected public who will be asked or required to respond, as well as a brief abstract: Primary:* Business or other for-profit. Other: Farms, State, Local, or Tribal Government, Individuals or households.

Need for Collection

The information is necessary for the safety of emergency response personnel responding to fires at sites where explosives are stored. The information is provided both orally and in writing to the authority having jurisdiction for fire safety in the locality in which explosives are stored.

(5) *An estimate of the total number of respondents and the amount of time estimated for an average respondent to respond:* It is estimated 1,025 respondents will complete the notification within approximately 30 minutes.

(6) *An estimate of the total burden (in hours) associated with the collection:* There are an estimated 513 annual total burden hours associated with this collection.

If additional information is required contact: Jerri Murray, Department Clearance Officer, Policy and Planning Staff, Justice Management Division, Department of Justice, Two Constitution Square, Room 2E–508, 145 N Street NE., Washington, DC 20530.

Jerri Murray,

Department Clearance Officer, PRA, United States Department of Justice.

[FR Doc. 2012–13168 Filed 5–30–12; 8:45 am]

BILLING CODE 4810–FY–P

DEPARTMENT OF JUSTICE

Bureau of Alcohol, Tobacco, Firearms and Explosives

[OMB Number 1140–0052]

Agency Information Collection Activities: Proposed Collection; Comments Requested; Strategic Planning Environmental Assessment Outreach

ACTION: 30-Day Notice of Information Collection Under Review:

The Department of Justice (DOJ), Bureau of Alcohol, Tobacco, Firearms and Explosives (ATF) will be submitting the following information collection request to the Office of Management and Budget (OMB) for review and approval in accordance with the Paperwork Reduction Act of 1995. The proposed information collection is published to obtain comments from the public and affected agencies. This proposed information collection was previously published in the **Federal Register** Volume 77, Number 58, page 17502 on March 26, 2012, allowing for a 60-day comment period.

The purpose of this notice is to allow for an additional 30 days for public comment until July 2, 2012. This process is conducted in accordance with 5 CFR 1320.10.

Written comments concerning this information collection should be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, Attn: DOJ Desk Officer. The best way to ensure your comments are received is to email them to *oira_submission@omb.eop.gov* or fax them to 202–395–7285. All comments should reference the eight digit OMB number or the title of the collection.

Written comments and suggestions from the public and affected agencies concerning the proposed collection of information are encouraged. Your comments should address one or more of the following four points:

—Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;
—Evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;
—Enhance the quality, utility, and clarity of the information to be collected; and
—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.

Summary of Collection

(1) *Type of Information Collection:* Extension of a currently approved collection.

(2) *Title of the Form/Collection:* Strategic Planning Environmental Assessment Outreach.

(3) *Agency form number, if any, and the applicable component of the Department of Justice sponsoring the collection: Form Number:* None. Bureau of Alcohol, Tobacco, Firearms and Explosives.

(4) *Affected public who will be asked or required to respond, as well as a brief abstract: Primary:* Business or other for-profit. Other: Not-for-profit institutions, Federal Government, State, Local, or Tribal Government.

Need for Collection

Under the provisions of the Government Performance and Results Act, Federal agencies are directed to improve their effectiveness and public accountability by promoting a new focus on results, service quality, and customer satisfaction. This act requires that agencies update and revise their strategic plans every three years. The Strategic Planning Office at ATF will use the voluntary outreach information to determine the agency's internal strengths and weaknesses.

(5) *An estimate of the total number of respondents and the amount of time estimated for an average respondent to respond:* It is estimated that 1,500 respondents will complete an 18-minute questionnaire.

(6) *An estimate of the total burden (in hours) associated with the collection:* There are an estimated 450 annual total burden hours associated with this collection.

If additional information is required contact: Jerri Murray, Department Clearance Officer, Policy and Planning Staff, Justice Management Division, Department of Justice, Two Constitution Square, 145 N Street NE., Room 2E–508, Washington, DC 20530.

Jerri Murray,

Department Clearance Officer, PRA, United States Department of Justice.

[FR Doc. 2012–13167 Filed 5–30–12; 8:45 am]

BILLING CODE 4810–FY–P

DEPARTMENT OF JUSTICE

Office of Justice Programs

[OMB No. 1121–0111]

Agency Information Collection Activities: Extension of a Currently Approved Collection; Comments Requested National Crime Victimization Survey (NCVS)

ACTION: 30-day notice of information collection under review.

The Department of Justice (DOJ), Office of Justice Programs, Bureau of Justice Statistics will be submitting the following information collection request to the Office of Management and Budget (OMB) for review and approval in accordance with the Paperwork Reduction Act of 1995. The proposed information collection is published to obtain comments from the public and affected agencies. This proposed information collection was previously published in the **Federal Register** Volume 77, Number 58, pages 17523–17524, on March 26, 2012, allowing for a 60-day comment period.

The purpose of this notice is to allow for an additional 30 days for public comment until July 2, 2012. This process is conducted in accordance with 5 CFR 1320.10.

Written comments and/or suggestions regarding the items contained in this notice, especially the estimated public burden and associated response time, should be directed to the Office of Management and Budget, Office of Information and Regulatory Affairs, Attention Department of Justice Desk Officer, Washington, DC 20503. Additionally, comments may be submitted to OMB via facsimile to (202) 395–5806.

Written comments and suggestions from the public and affected agencies concerning the proposed collection of information are encouraged. Your comments should address one or more of the following four points:

—Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;
—Evaluate the accuracy of the agencies 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.

Overview of this Information

(1) *Type of information collection:* Extension of a currently approved collection.

(2) *Title of the Form/Collection:* National Crime Victimization Survey (NCVS).

(3) *Agency form number, if any, and the applicable component of the department sponsoring the collection:* NCVS. Bureau of Justice Statistics, Office of Justice Programs, Department of Justice.

(4) *Affected public who will be asked or required to respond, as well as a brief abstract. Primary:* Persons 12 years or older living in NCVS sampled households located throughout the United States. The National Crime Victimization Survey (NCVS) collects, analyzes, publishes, and disseminates statistics on criminal victimization in the U.S.

(5) *An estimate of the total number of respondents and the amount of time estimated for an average respondent to respond/reply:* An estimate of the total number of respondents is 84,700. It will take the average interviewed respondent an estimated 23 minutes to respond, the average non-interviewed respondent an estimated 7 minutes to respond, the estimated average follow-up interview is 12 minutes, and the estimated average follow-up for a non-interview is 1 minute.

(6) *An estimate of the total public burden (in hours) associated with the collection:* The total respondent burden is approximately 67,657 hours.

If additional information is required contact: Jerri Murray, Department Clearance Officer, United States Department of Justice, Justice Management Division, Policy and Planning Staff, 145 N Street NE., Room 2E–508, Washington, DC 20530.

Jerri Murray,

Department Clearance Officer, PRA, United States Department of Justice.

[FR Doc. 2012–13161 Filed 5–30–12; 8:45 am]

BILLING CODE 4410–18–P

DEPARTMENT OF JUSTICE

Office of Justice Programs

[OMB 1121–NEW]

Agency Information Collection Agencies: Proposed Collection; Comments Requested Census of Problem-Solving Courts 2012

ACTION: 30-Day notice of information collection under review.

The Department of Justice, Office of Justice Programs, Bureau of Justice Statistics, will be submitting the following information collection request for review and approval in accordance with the Paperwork Reduction Act of 1995. The proposed information collection is published to obtain comments from the public and affected agencies. The proposed information collection was previously published in the **Federal Register** 77, Number 58, pages 17522–17523, on March 26, 2012, allowing a 60-day public comment period.

The purpose of this notice is to allow an additional 30 days for public comment until July 2, 2012. This process is conducted in accordance with 5 CFR 1320.10.

Written comments and/or suggestions regarding items in this notice, especially on the estimated public burden or associated response time, should be directed to the Office of Management and Budget, Office of Regulatory Affairs, Attention Department of Justice Desk Officer, Washington, DC 20503. Additionally, comments may be submitted to OMB via facsimile to 202–395–7285.

Written comments and suggestions from the public and affected agencies concerning the proposed collection of information are encouraged. Your comments should address one or more of the following four points:

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, including the validity of the methodology and assumptions used;

3. Enhance the quality, utility, and clarity of the information to be collected; and

4. Minimize the burden of 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.

Overview of this information:

1. *Type of information collection:* New data collection, Census of Problem-Solving Courts (CPSC), 201

2. *The title of the form/collection:* Census of Problem-Solving Courts or CPSC 2012

3. *The agency form number, if any, and the applicable component of the Department sponsoring the collection:* The form labels are CPSC, Bureau of Justice Statistics, Office of Justice Programs, U.S. Department of Justice

4. *Affected Public Who Will be Asked or Required to Respond, as well as a Brief Abstract:* Problem-solving courts at all levels of government. Abstract: The Bureau of Justice Statistics (BJS) proposes to implement a Census of Problem-Solving Courts (CPSC). Problem-solving courts target defendants who have ongoing social and/or psychological conditions that underlie their repeated contact with the criminal justice system. Most of the existing information about problem-solving courts (PSC) consists of court evaluations or outcome analyses. No prior census of these courts has been conducted to date despite the substantial proliferation of such courts during the past thirty years. Hence, the CPSC will allow BJS to provide national level information on problem-solving courts and case processing statistics.

The CPSC is designed to provide BJS and other interested stakeholders with the first systematic empirical information on problem-solving courts. A goal of the census is to obtain information on problem-solving court operations, staffing, administration, and to generate accurate and reliable aggregate statistics on offenders who enter problem-solving court programs. Information will be collected for the most recent 12-month period in 2012. The CPSC will collect information on the following categories:

a. Court Operations and Staffing

i. Provide the number of problem-solving courts by type (e.g., mental health, drug, etc.),

ii. Determine PSCs level of government operations (e.g., local, state, etc.), court jurisdiction (e.g., limited, general, other) and intake of felony, misdemeanor, or status offenses,

iii. Court session frequency,

iv. Number of full- and part-time staff members currently employed by PSCs.

b. Funding: Types and prevalence of PSC funding (e.g., local government budget, state budget, etc.)

c. Commonly Used Services:

i. Count the types and prevalence of offender/victim services (e.g., anger management), counseling or treatment services (e.g., outpatient mental health treatment), and general supportive services (e.g., life skills)

d. Participant participation

i. Participant inclusionary and exclusionary factors,

ii. Participant point of entry (e.g. pre-plea, post-plea/pre-sentence, etc.)

iii. Case closure: Benefits of successful participation in PSC program (e.g., case dismissal).

e. Capacity and Enrollment

i. Design Capacity: Total number of active participants PSC can manage at any one time,

ii. Current number of active participants.

f. Data Collection Practices:

i. Use of automated case management systems,

ii. Ability to share case management information with external agencies,

iii. PSCs' ability to track participant outcomes after graduation.

g. Selected PSC Aggregate Participant information:

i. Number of offenders admitted for participation in PSC over a 12 month period,

ii. Number of offender participants exiting program over a 12 month period, including type of exit (e.g., successful program completion),

iii. Percentage of participants by gender over a 12 month period,

iv. Percentage of participants by race/ethnicity over a 12 month period.

5. *An Estimate of the Total Number of Respondents and the Amount of Time Estimated for an Average Respondent to Respond:* Estimates suggest 3,800 respondents will take part in the Census of Problem-Solving Courts 2012. Based on pilot testing and in-house review, the average (mean) burden for each completed survey is expected to be approximately 30 minutes per respondent. The estimated range of burden for respondents is expected to be between 15 minutes to 1 hour for completion. The following factors were considered when creating the burden estimate: the estimated total number of problem-solving courts, the ability of problem-solving courts to access data, and the type of data capabilities generally found in the field. BJS estimates that nearly all of the approximately 3,800 respondents will fully complete the questionnaire.

6. *An Estimate of the Total Public Burden (in hours) Associated with the collection:* The estimated public burden associated with this collection is 1,918 hours. It is estimated that respondents will take 30 minutes to complete a questionnaire. The burden hours for collecting respondent data sum to 1,900 hours (3,800 respondents x 0.5 hours = 1,900 hours). In addition to respondents' burden of completing the census questionnaire, the CPSC requires voluntary participation from State Points of Contacts (SPOCs) to develop an initial list of problem-solving court docket contact information. While SPOCs will not complete actual questionnaires, their effort is a necessary first step in identifying the universe of problem-solving courts nationwide. BJS estimates it will take, on average, 20 minutes for each SPOC to provide the requested list of problem-solving courts in their respective state. There are 54 SPOCS (including DC, Guam, Virgin Islands, and Puerto Rico). The total time burden is 18 hours (54 SPOCS x 20 minutes = 18 hours). Therefore the total estimated burden for the entire CPSC 2012 project is 1,918 hours (1,900 hours for respondents + 18 hours for SPOCS = 1,918 hours).

If additional information is required contact: Jerri Murray, Department Clearance Officer, United States Department of Justice, Justice Management Division, Policy and Planning Staff, Two Constitution Square, 145 N Street NE., Room 2E–508, Washington, DC 20530.

Jerri Murray

Department Clearance Officer, PRA, U.S. Department of Justice.

[FR Doc. 2012–13162 Filed 5–30–12; 8:45 am]

BILLING CODE 4410–18–P

DEPARTMENT OF LABOR

Office of the Secretary

Agency Information Collection Activities; Submission for OMB Review; Comment Request; Foreign Labor Certification Quarterly Activity Report

ACTION: Notice.

SUMMARY: On May 31, 2012 the Department of Labor (DOL) will submit the Employment and Training Administration (ETA) sponsored information collection request (ICR) revision titled, ''Foreign Labor Certification Quarterly Activity Report,'' to the Office of Management and Budget (OMB) for review and approval for use in accordance with the Paperwork Reduction Act (PRA) of 1995 (44 U.S.C. 3501 *et seq.*).

DATES: Submit comments on or before July 2, 2012.

ADDRESSES: A copy of this ICR with applicable supporting documentation; including a description of the likely respondents, proposed frequency of response, and estimated total burden may be obtained from the RegInfo.gov Web site, *http://www.reginfo.gov/public/do/PRAMain,* on the day following publication of this notice or by contacting Michel Smyth by telephone at 202–693–4129 (this is not a toll-free number) or sending an email to *DOL_PRA_PUBLIC@dol.gov.*

Submit comments about this request to the Office of Information and Regulatory Affairs, Attn: OMB Desk Officer for DOL–ETA, Office of Management and Budget, New Executive Office Building, Room 10235, Washington, DC 20503, Telephone: 202–395–6929/Fax: 202–395–6881 (these are not toll-free numbers), email: *OIRA_submission@omb.eop.gov.*

FOR FURTHER INFORMATION: Contact Michel Smyth by telephone at 202–693–4129 (this is not a toll-free number) or by email at *DOL_PRA_PUBLIC@dol.gov.*

SUPPLEMENTARY INFORMATION: The Foreign Labor Certification Quarterly Activity Report, Form ETA–9127, is used to collect information from a State Workforce Agency (SWA) on activities performed under a Foreign (Alien) Labor Certification reimbursable grant and provides a sound basis for program management, including budget, workload management, and monitoring for compliance with the grant. A new information collection component has been added to this ICR, to account for the surveys conducted by the SWAs to collect information about prevailing employment practices in agriculture.

This information collection is subject to the PRA. A Federal agency generally cannot conduct or sponsor a collection of information, and the public is generally not required to respond to an information collection, unless it is approved by the OMB under the PRA and displays a currently valid OMB Control Number. In addition, notwithstanding any other provisions of law, no person shall generally be subject to penalty for failing to comply with a collection of information if the collection of information does not display a valid OMB Control Number. *See* 5 CFR 1320.5(a) and 1320.6. The DOL obtains OMB approval for this information collection under OMB Control Number 1205–0457. The current OMB approval is scheduled to expire on May 31, 2012; however, it should be noted that existing information collection requirements submitted to the OMB receive a month-to-month extension while they undergo review. New provisions would only take effect after OMB approves them. For additional information, see the related notice published in the **Federal Register** on March 27, 2012 (77 FR 18267).

Interested parties are encouraged to send comments to the OMB, Office of Information and Regulatory Affairs at the address shown in the **ADDRESSES** section within 30 days of publication of this notice in the **Federal Register**. In order to help ensure appropriate consideration, comments should reference OMB Control Number 1205–0457. The OMB is particularly interested in comments that:

• Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;

• Evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;

• Enhance the quality, utility, and clarity of the information to be collected; and

• Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, e.g., permitting electronic submission of responses.

Agency: DOL–ETA.

Title of Collection: Foreign Labor Certification Quarterly Activity Report.

OMB Control Number: 1205–0457.

Affected Public: State, Local, and Tribal Governments and Private Sector—Farms.

Total Estimated Number of Respondents: 10,054.

Total Estimated Number of Responses: 11,716.

Total Estimated Annual Burden Hours: 6,170.

Total Estimated Annual Other Costs Burden: $0.

Dated: May 24, 2012.

Michel Smyth,

Departmental Clearance Officer.

[FR Doc. 2012–13109 Filed 5–30–12; 8:45 a.m.]

BILLING CODE 4510–FP–P

DEPARTMENT OF LABOR

Office of Workers' Compensation Programs

Division of Coal Mine Workers' Compensation Proposed Extension of Existing Collection; Comment Request

ACTION: Notice.

SUMMARY: The Department of Labor, as part of its continuing effort to reduce paperwork and respondent burden, conducts a pre-clearance consultation program to provide the general public and Federal agencies with an opportunity to comment on proposed and/or continuing collections of information in accordance with the Paperwork Reduction Act of 1995 (PRA95) [44 U.S.C. 3506(c)(2)(A)]. This program helps to ensure that requested data can be provided in the desired format, reporting burden (time and financial resources) is minimized, collection instruments are clearly understood, and the impact of collection requirements on respondents can be properly assessed. Currently, the Office of Workers' Compensation Programs is soliciting comments concerning the proposed collection: *Authorization for Release of Medical Information (CM–936).* A copy of the proposed information collection request can be obtained by contacting the office listed below in the addresses section of this Notice.

DATES: Written comments must be submitted to the office listed in the addresses section below on or before July 30, 2012.

ADDRESSES: Ms. Yoon Ferguson, U.S. Department of Labor, 200 Constitution Ave. NW., Room S–3201, Washington, DC 20210, telephone (202) 693–0701, fax (202) 693–1447, Email *ferguson.yoon@dol.gov.* Please use only one method of transmission for comments (mail, fax, or Email).

SUPPLEMENTARY INFORMATION:

I. Background

The Black Lung Benefits Act, as amended, 30 U.S.C. 901, and 20 CFR 725.405, requires that all relevant medical evidence be considered before a decision can be made regarding a claimant's eligibility for benefits. The CM–936 is a form that gives the claimant's consent for release of information, required by the Privacy Act, and contains information required by medical institutions and private physicians to enable them to release pertinent medical information. This information collection is currently approved for use through November 30, 2012.

II. Review Focus

The Department of Labor 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 submissions of responses.

III. Current Actions

The Department of Labor seeks approval for the extension of this currently-approved information collection in order to obtain claimant consent for the release of medical information for consideration by the Division of Coal Mine Workers' Compensation as evidence to support their claim for benefits. Failure to gather this information would inhibit the adjudication of black lung claims because pertinent medical data would not be available for consideration during the processing of the claim.

Agency: Office of Workers' Compensation Programs.

Type of Review: Extension.

Title: Authorization for Release of Medical Information.

OMB Number: 1240–0034.

Agency Number: CM–936.

Affected Public: Individuals or households.

Total Respondents: 900.

Total Annual Responses: 900.

Average Time per Response: 5 minutes.

Estimated Total Burden Hours: 75.

Frequency: On occasion.

Total Burden Cost (capital/startup): $0.

Total Burden Cost (operating/maintenance): $3,671.

Comments submitted in response to this notice will be summarized and/or included in the request for Office of Management and Budget approval of the information collection request; they will also become a matter of public record.

Dated: May 24, 2012.

Yoon Ferguson,

Agency Clearance Officer, Office of Workers' Compensation Programs U.S. Department of Labor.

[FR Doc. 2012–13119 Filed 5–30–12; 8:45 am]

BILLING CODE 4510–CK–P

NATIONAL ARCHIVES AND RECORDS ADMINISTRATION

Privacy Act of 1974, as Amended; System of Records Notices

AGENCY: National Archives and Records Administration.

ACTION: Notice; new privacy system of records titled ''Internal Collaboration Network''.

SUMMARY: The National Archives and Records Administration (NARA) proposes to add a system of records to its existing inventory of systems subject to the Privacy Act of 1974, as amended (5 U.S.C. 552(a)) (''Privacy Act''). In this notice, NARA publishes NARA 43, the Internal Collaboration Network, which contains files with information on National Archives employees, volunteers, and contractors.

DATES: This new system of records, NARA 43, will become effective July 2, 2012 without further notice unless comments are received that result in further revision. NARA will publish a new notice if the effective date is delayed to review comments or if changes are made based on comments received. To be assured of consideration, comments should be received on or before the date above.

ADDRESSES: You may submit comments, identified by SORN number NARA 43, by one of the following methods:

• *Federal e-Rulemaking Portal: http://www.regulations.gov.* Follow the instructions for submitting comments.

• *Fax:* 301–837–0293.

• *Mail:* Laura McCarthy, Strategy Division, Room 4100, National Archives and Records Administration, 8601 Adelphi Road, College Park, MD 20740–6001.

FOR FURTHER INFORMATION CONTACT: Pamela Wright, Open Government Office, Room 3200, National Archives and Records Administration, 8601 Adelphi Road, College Park, MD 20740–6001. Telephone: (301) 837–2029. Fax: 301–837–0312.

SUPPLEMENTARY INFORMATION: The Internal Collaboration Network is a web-based platform that allows users to better collaborate on work projects across geographic locations and offices and allow the agency to better preserve NARA's institutional knowledge. The platform allows for user-generated content in the form of documents, polls, ideas, blog posts, user profiles, project management and commenting features.

The notice for this system of records states the name and the location of the record system, the authority for and manner of its operation, the categories of individuals that it covers, the types of records that it contains, the sources of information in the records, and the proposed ''routine uses'' of the system of records. The notice also includes the business address of the NARA official who will inform interested persons of the procedures whereby they may gain access to, and correct, records pertaining to themselves.

One of the purposes of the Privacy Act, as stated in section 2(b)(4) of the Act, is to provide certain safeguards for an individual against an invasion of personal privacy by requiring Federal agencies to disseminate any record of identifiable personal information in a manner that assures that such action is for a necessary and lawful purpose, that the information is current and accurate for its intended use, and that adequate safeguards are provided to prevent misuse of such information. NARA intends to follow these principles in transferring information to another agency or individual as a ''routine use'' including assurance that the information is relevant for the purposes for which it is transferred.

Dated: May 21, 2012.

David S. Ferriero,

Archivist of the United States.

NARA Privacy Act Systems: NARA 43

SYSTEM NAME:

Internal Collaboration Network

SYSTEM LOCATION:

The Internal Collaboration Network files are maintained electronically on servers under the control of the National Technical Information Center as part of the Department of Commerce. NTIS servers are located in Alexandria, Virginia.

CATEGORIES OF INDIVIDUALS COVERED BY THE SYSTEM:

Individuals covered by this system include all ICN users. ICN users can include National Archives employees, volunteers, and contractors.

CATEGORIES OF RECORDS IN THE SYSTEM:

The ICN files may include any of the following information about users in the user profile: name, title, department, home address, work address, home phone, work phone, mobile phone, hire date, biography, expertise, personal email, and official duty station. Users are not required to share information other than name and work email. Users may collaborate on the network to create other files including: discussion threads, interest groups, project plans, tasks, ideas, and documents.

AUTHORITY FOR MAINTENANCE OF THE SYSTEM:

5 U.S.C. 552a(a)(3), as amended.

44 U.S.C. 2104(a), as amended.

ROUTINE USES OF RECORDS MAINTAINED IN THE SYSTEM, INCLUDING CATEGORIES OF USERS AND THE PURPOSES OF SUCH USES:

NARA maintains ICN files for the benefit and use of all ICN users to enhance communication and collaboration among all users and to facilitate the work flow among all NARA locations and offices. The routine use statements A, B, C, D, E, F, G, and H described in Appendix A, published in the **Federal Register** at 72 FR 56570–01 and available on *www.archives.gov,* apply to this system of records.

POLICIES AND PRACTICES FOR STORING, RETRIEVING, ACCESSING, RETAINING, AND DISPOSING OF RECORDS IN THE SYSTEM:

STORAGE:

Electronic records.

RETRIEVABILITY:

Information in these case files may be retrieved by the name of the individual or key word. All content is fully searchable and indexed.

SAFEGUARDS:

The files are at all times maintained in a secure network environment, in compliance with the Federal Information Management and Security Act system security requirements at a moderate-impact system level.

RETENTION AND DISPOSAL:

NARA ICN files are unscheduled at this time.

SYSTEM MANAGER(S) AND ADDRESS:

The system manager is Pamela Wright, Open Government Office, Room 3200, National Archives and Records Administration, 8601 Adelphi Road, College Park, MD 20740–6001. Telephone: (301) 837–2029. Fax: 301–837–0312.

NOTIFICATION PROCEDURE:

Individuals interested in inquiring about their records should notify the NARA Privacy Act Officer at the Privacy Act Officer, Room 3110, National Archives and Records Administration, 8601 Adelphi Road, College Park, MD 20740–6001.

RECORDS ACCESS PROCEDURES:

Individuals who wish to gain access to their records should submit their request in writing to the NARA Privacy Act Officer the address listed above.

CONTESTING RECORDS PROCEDURES:

NARA rules for contesting the contents and appealing initial determinations are found in 36 CFR part 1202.

RECORDS SOURCE CATEGORIES:

Information in the ICN is obtained directly from the ICN users, except in cases of name and work email address, which is populated automatically by the system.

[FR Doc. 2012–13200 Filed 5–30–12; 8:45 am]

BILLING CODE 7515–01–P

NATIONAL ARCHIVES AND RECORDS ADMINISTRATION

Privacy Act of 1974, as Amended; System of Records Notices

AGENCY: National Archives and Records Administration.

ACTION: Notice; new privacy system of records titled ‘‘Contestant Application Files’’.

SUMMARY: The National Archives and Records Administration (NARA) proposes to add a system of records to its existing inventory of systems subject to the Privacy Act of 1974, as amended (5 U.S.C. 552(a)) (‘‘Privacy Act’’). In this notice, NARA publishes NARA 42, the Contestant Applications, which includes persons who entered contests conducted by NARA.

DATES: This new system of records, NARA 42, will become effective May 31, 2012 without further notice unless comments are received that result in further revision. NARA will publish a new notice if the effective date is delayed to review comments or if changes are made based on comments received. To be assured of consideration, comments should be received on or before the date above.

ADDRESSES: You may submit comments, identified by SORN number NARA 42, by one of the following methods:

- *Federal e-Rulemaking Portal: http://www.regulations.gov.* Follow the instructions for submitting comments.
- *Fax:* 301–837–0293.
- *Mail:* Laura McCarthy, Strategy Division, Room 4100, National Archives and Records Administration, 8601 Adelphi Road, College Park, MD 20740–6001.

FOR FURTHER INFORMATION CONTACT: Pamela Wright, Open Government Office, Room 3200, National Archives and Records Administration, 8601 Adelphi Road, College Park, MD 20740–6001. Telephone: (301) 837–2029. Fax: 301–837–0312.

SUPPLEMENTARY INFORMATION: The America Competes Act, H.R. 5116, signed into law on Jan. 4, 2011, authorizes Federal agencies to carry out a program to award prizes competitively to stimulate innovation that has the potential to advance the mission of the respective agency. The National Archives conducts contests in accordance with this statutory authority.

The notice for this system of records states the name and the location of the record system, the authority for and manner of its operation, the categories of individuals that it covers, the types of records that it contains, the sources of information in the records, and the proposed ‘‘routine uses’’ of the system of records. The notice also includes the business address of the NARA official who will inform interested persons of the procedures whereby they may gain access to, and correct, records pertaining to themselves.

One of the purposes of the Privacy Act, as stated in section 2(b)(4) of the Act, is to provide certain safeguards for an individual against an invasion of personal privacy by requiring Federal agencies to disseminate any record of identifiable personal information in a manner that assures that such action is for a necessary and lawful purpose, that the information is current and accurate for its intended use, and that adequate safeguards are provided to prevent misuse of such information. NARA intends to follow these principles in transferring information to another agency or individual as a ‘‘routine use’’ including assurance that the information is relevant for the purposes for which it is transferred.

Dated: May 21, 2012.

David S. Ferriero,

Archivist of the United States.

NARA Privacy Act Systems: NARA 42

SYSTEM NAME:

Contestant Application Files.

SYSTEM LOCATION:

The Contestant Application files are maintained in the regional archives, presidential library, or NARA headquarters facility that organized the competition, contest, or challenge. Addresses are located at *http://www.archives.gov/locations/*. Contestant application information may also be maintained electronically on the Web site through which the contest was conducted, such as *www.challenge.gov*.

CATEGORIES OF INDIVIDUALS COVERED BY THE SYSTEM:

Individuals covered by this system include persons who entered contests conducted by the National Archives and Records Administration.

CATEGORIES OF RECORDS IN THE SYSTEM:

The Contestant Applications may contain some or all of the following information: the user name under which the entry was submitted, name, email address, mailing address, phone number, contestant submission, prize information if one was awarded, parental or legal guardian information in the event the applicant was a minor, grant of license to use intellectual property associated with the contest submission, and any additional information provided by the contestant related to the administration of the competition.

AUTHORITY FOR MAINTENANCE OF THE SYSTEM:

5 U.S.C. 552a(a)(3), as amended.
44 U.S.C. 2104(a), as amended.
42 U.S.C. 1861.

ROUTINE USES OF RECORDS MAINTAINED IN THE SYSTEM, INCLUDING CATEGORIES OF USERS AND THE PURPOSES OF SUCH USES:

NARA maintains the contest applicant information and related information concerning contest submissions. Routine uses A, B, C, D, E, F, G, and H listed in Appendix A apply to this system.

POLICIES AND PRACTICES FOR STORING, RETRIEVING, ACCESSING, RETAINING, AND DISPOSING OF RECORDS IN THE SYSTEM:

STORAGE:

Paper and electronic records.

RETRIEVABILITY:

Information in these case files may be retrieved by the user name of the contestant, name contest information, location of contestant or other field provided by the electronic platform on which the contest is hosted.

SAFEGUARDS:

The case files are at all times maintained in buildings with secured doors. During business hours records are accessible only by authorized NARA personnel. Electronic records are accessible via secure user names and passwords. After business hours, or when NARA personnel are not present in the offices, the paper records are secured in locked filing cabinets.

RETENTION AND DISPOSAL:

NARA contestant application files are temporary records and are destroyed in accordance with the disposition instructions in the NARA Records Schedule supplement to FILES 203, the NARA Files Maintenance and Records Disposition Manual. Individuals may request a copy of the disposition instructions from the NARA Privacy Act Officer.

SYSTEM MANAGER(S) AND ADDRESS:

For these case files, the system manager is Jill James, Office of Information Services, Room 3200, National Archives and Records Administration, 8601 Adelphi Road, College Park, MD 20740–6001. Telephone: (301) 837–0760. Fax: 301–837–0312.

NOTIFICATION PROCEDURE:

Individuals interested in inquiring about their records are to notify the NARA Privacy Act Officer at the address listed in Appendix B following the NARA notice.

RECORDS ACCESS PROCEDURES:

Individuals interested in inquiring about their records should notify the NARA Privacy Act Officer at the Privacy Act Officer, Room 3110, National Archives and Records Administration, 8601 Adelphi Road, College Park, MD 20740–6001.

CONTESTING RECORDS PROCEDURES:

NARA rules for contesting the contents and appealing initial determinations are found in 36 CFR part 1202.

RECORDS SOURCE CATEGORIES:

Information in these contestant application files is obtained from persons who participate in contests organized by the National Archives.

[FR Doc. 2012–13201 Filed 5–30–12; 8:45 am]

BILLING CODE 7515–01–P

NATIONAL SCIENCE FOUNDATION

Agency Information Collection Activities: Comment Request

AGENCY: National Science Foundation.

ACTION: Submission for OMB Review; Comment Request.

SUMMARY: The National Science Foundation (NSF) has submitted the following information collection requirement to OMB for review and clearance under the Paperwork Reduction Act of 1995, Public Law 104–13. This is the *second notice* for public comment; the first was published in the **Federal Register** at 77 FR 5580, and no comments were received. NSF is forwarding the proposed renewal submission to the Office of Management and Budget (OMB) for clearance simultaneously with the publication of this second notice. The full submission may be found at: *http://www.reginfo.gov/public/do/PRAMain*. Comments regarding (a) whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility; (b) the accuracy of the agency's estimate of burden including the validity of the methodology and assumptions used; (c) ways to enhance the quality, utility and clarity of the information to be collected; (d) ways to minimize the burden of the collection of information on 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 should be addressed to: Office of Information and Regulatory Affairs of OMB, Attention: Desk Officer for National Science Foundation, 725—17th Street NW., Room 10235, Washington, DC 20503, and to Suzanne H. Plimpton, Reports Clearance Officer, National Science Foundation, 4201 Wilson Boulevard, Suite 295, Arlington, Virginia 22230 or send email to *splimpto@nsf.gov*. Individuals who use a telecommunications device for the deaf (TDD) may call the Federal Information Relay Service (FIRS) at 1–800–877–8339, which is accessible 24 hours a day, 7 days a week, 365 days a year (including Federal holidays).

Comments regarding these information collections are best assured of having their full effect if received within 30 days of this notification. Copies of the submission(s) may be obtained by calling 703–292–7556.

NSF may not conduct or sponsor a collection of information unless the

collection of information displays a currently valid OMB control number and the agency informs potential persons who are to respond to the collection of information that such persons are not required to respond to the collection of information unless it displays a currently valid OMB control number.

SUPPLEMENTARY INFORMATION:

Title of Collection: Grantee Reporting Requirements for Science and Technology Centers (STC): Integrative Partnerships.

OMB Number: 3145–0194.

Type of Request: Intent to seek approval to extend an information collection.

Abstract:

Proposed Project: The Science and Technology Centers (STC): Integrative Partnerships Program supports innovation in the integrative conduct of research, education and knowledge transfer. Science and Technology Centers build intellectual and physical infrastructure within and between disciplines, weaving together knowledge creation, knowledge integration, and knowledge transfer. STCs conduct world-class research through partnerships of academic institutions, national laboratories, industrial organizations, and/or other public/private entities. New knowledge thus created is meaningfully linked to society.

STCs enable and foster excellent education, integrate research and education, and create bonds between learning and inquiry so that discovery and creativity more fully support the learning process. STCs capitalize on diversity through participation in center activities and demonstrate leadership in the involvement of groups underrepresented in science and engineering.

Centers selected will be required to submit annual reports on progress and plans, which will be used as a basis for performance review and determining the level of continued funding. To support this review and the management of a Center, STCs will be required to develop a set of management and performance indicators for submission annually to NSF via an NSF evaluation technical assistance contractor. These indicators are both quantitative and descriptive and may include, for example, the characteristics of center personnel and students; sources of financial support and in-kind support; expenditures by operational component; characteristics of industrial and/or other sector participation; research activities; education activities; knowledge transfer activities; patents, licenses; publications; degrees granted to students involved in Center activities; descriptions of significant advances and other outcomes of the STC effort. Part of this reporting will take the form of a database which will be owned by the institution and eventually made available to an evaluation contractor. This database will capture specific information to demonstrate progress towards achieving the goals of the program. Such reporting requirements will be included in the cooperative agreement which is binding between the academic institution and the NSF.

Each Center's annual report will address the following categories of activities: (1) Research, (2) education, (3) knowledge transfer, (4) partnerships, (5) diversity, (6) management and (7) budget issues.

For each of the categories the report will describe overall objectives for the year, problems the Center has encountered in making progress towards goals, anticipated problems in the following year, and specific outputs and outcomes.

Use of the Information: NSF will use the information to continue funding of the Centers, and to evaluate the progress of the program.

Estimate of Burden: 100 hours per center for seventeen centers for a total of 1700 hours.

Respondents: Non-profit institutions; Federal government.

Estimated Number of Responses per Report: One from each of the seventeen centers.

Dated: May 24, 2012.

Suzanne H. Plimpton,

Reports Clearance Officer, National Science Foundation.

[FR Doc. 2012–13139 Filed 5–30–12; 8:45 am]

BILLING CODE 7555–01–P

NATIONAL SCIENCE FOUNDATION

Agency Information Collection Activities: Comment Request; Generic Survey Clearance for the Directorate of Education and Human Resources (EHR)

AGENCY: National Science Foundation.

ACTION: Notice.

SUMMARY: The National Science Foundation (NSF) is announcing plans to request renewed clearance of this collection. In accordance with the requirement of section 3506(c)(2)(A) of the Paperwork Reduction Act of 1995, we are providing opportunity for public comment on this action. After obtaining and considering public comment, NSF will prepare the submission requesting Office of Management and Budget (OMB) clearance of this collection for no longer than 3 years.

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 on respondents, including through the use of automated collection techniques or other forms of information technology; 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.

DATES: Written comments should be received by January 3, 2011 to be assured of consideration. Comments received after that date will be considered to the extent practicable.

ADDRESSES: Written comments regarding the information collection and requests for copies of the proposed information collection request should be addressed to Suzanne Plimpton, Reports Clearance Officer, National Science Foundation, 4201 Wilson Blvd., Rm. 295, Arlington, VA 22030, or by email to *splimpto@nsf.gov.*

FOR FURTHER INFORMATION CONTACT: Suzanne Plimpton at (703) 292–7556 or send email to *splimpto@nsf.gov.* Individuals who use a telecommunications device for the deaf (TDD) may call the Federal Information Relay Service (FIRS) at 1–800–877–8339, which is accessible 24 hours a day, 7 days a week, 365 days a year (including federal holidays).

SUPPLEMENTARY INFORMATION: *Title of Collection:* Generic Clearance of Education and Human Resources Monitoring of Grantee Projects.

OMB Approval Number: 3145–0136.

Expiration Date of Approval: July 31, 2012.

Abstract: The National Science Foundation (NSF) requests renewal of program accountability data collections that describe and track the impact of NSF funding that focuses on the Nation's science, technology, engineering, and mathematics (STEM) education and STEM workforce. NSF funds grants, contracts, and cooperative agreements to colleges, universities, and other eligible institutions, and provides graduate research fellowships to individuals in all parts of the United States and internationally.

The Directorate for Education and Human Resources (EHR), a unit within NSF, promotes rigor and vitality within the Nation's STEM education enterprise to further the development of the 21st century's STEM workforce and public scientific literacy. EHR does this through diverse projects and programs that support research, extension, outreach, and hands-on activities that service STEM learning and research at all institutional (*e.g.,* pre-school through postdoctoral) levels in formal and informal settings; and individuals of all ages (birth and beyond). EHR also focuses on broadening participation in STEM learning and careers among United States citizens, permanent residents, and nationals, particularly those individuals traditionally underemployed in the STEM research workforce, including but not limited to women, persons with disabilities, and racial and ethnic minorities.

The scope of the EHR Generic Clearance primarily covers descriptive information gathered from education and training projects that are funded by NSF. NSF primarily uses the data from the EHR Generic Clearance for program planning, management, and audit purposes to respond to queries from the Congress, the public, NSF's external merit reviewers who serve as advisors, including Committees of Visitors (COVs), the NSF's Office of the Inspector General and as a basis for either internal or third-party evaluations of individual programs.

The collections generally include three categories of descriptive data: (1) Staff and project participants (data that are also necessary to determine individual-level treatment and control groups for future third-party study or for internal evaluation); (2) project implementation characteristics (also necessary for future use to identify well-matched comparison groups); and (3) project outputs (necessary to measure baseline for pre- and post-NSF-funding-level impacts).

Use of the Information: This information is required for effective administration, communication, program and project monitoring and evaluation, and for measuring attainment of NSF's program, project, and strategic goals, and as identified by the President's Accountability in Government Initiative; GPRA, and the NSF's Strategic Plan. The Foundation's FY 2011–2016 Strategic Plan may be found at: *http://www.nsf.gov/news/strategicplan/nsfstrategicplan_2011_2016.pdf.*

Since the EHR Generic Clearance research is primarily used for accountability and evaluation purposes, including responding from queries from COVs and other scientific experts, a census rather than sampling design typically is necessary. At the individual project level funding can be adjusted based on individual project's responses to some of the surveys. Some data collected under the EHR Clearance serve as baseline data for separate research and evaluation studies.

NSF-funded contract or grantee researchers and internal or external evaluators in part may identify control, comparison, or treatment groups for NSF's ET portfolio using some of the descriptive data gathered through OMB 3145–0136 to conduct well-designed, rigorous research and portfolio evaluation studies.

Respondents: Individuals or households, not-for-profit institutions, business or other for profit, and Federal, State, local or tribal government.

Number of Respondents: 9,341.

Burden on the Public: NSF estimates that a total reporting and recordkeeping burden of 63,947 hours will result from activities to monitor EHR STEM education programs. The calculation is shown in table 1.

TABLE 1—ANTICIPATED PROGRAMS THAT WILL COLLECT DATA ON PROJECT PROGRESS AND OUTCOMES ALONG WITH THE NUMBER OF RESPONDENTS AND BURDEN HOURS PER COLLECTION PER YEAR

Collection title	Number of respondents	Number of responses	Annual hour burden
Centers of Research Excellence in Science and Technology (CREST) and Historically Black Colleges and Universities Research Infrastructure for Science and Engineering (HBCU–RISE) Monitoring System	37	37	1,374
Graduate STEM Fellows in K–12 Education (GK–12) Monitoring System	1,626	1,626	3,941
Integrative Graduate Education and Research Traineeship Program (IGERT) Monitoring System	4,658	4,658	12,156
Informal Science Education (ISE) Monitoring System	157	157	2,047
Louis Stokes Alliances for Minority Participation (LSAMP) Monitoring System	518	518	17,094
Louis Stokes Alliances for Minority Participation Bridge to the Doctorate (LSAMP–BD) Monitoring System	50	50	3,600
Robert Noyce Teacher Scholarship Program (Noyce) Monitoring System	294	294	3,822
Research in Disabilities Education (RDE) Monitoring System	49	49	2,781
Scholarships in Science, Technology, Engineering, and Mathematics Program (S–STEM) Monitoring System	500	[1] 1,000	6,000
Science, Technology, Engineering, and Mathematics Talent Expansion Program (STEP) Monitoring System	242	242	6,292
Transforming Undergraduate Education in Science, Technology, Engineering, and Mathematics (TUES) Monitoring System	1,210	1,210	4,840
Additional Collections not Specified	900	900	1,200
Total	10,241	10,741	65,147

[1] (500 respondents × 2 responses/yr.).

The total estimate for this collection is 63,947 annual burden hours. This figure is based on the previous 3 years of collecting information under this clearance and anticipated collections. The average annual reporting burden is between 1.5 and 72 hours per ''respondent,'' depending on whether a respondent is a direct participant who is self-reporting or representing a project and reporting on behalf of many project participants. This is a reduction from the prior clearance of approximately 2,000 hours per year.

Dated: May 24, 2012.

Suzanne H. Plimpton,

Reports Clearance Officer, National Science Foundation.

[FR Doc. 2012–13196 Filed 5–30–12; 8:45 am]

BILLING CODE 7555–01–P

NUCLEAR REGULATORY COMMISSION

[NRC–2012–0066]

Agency Information Collection Activities: Proposed Collection; Comment Request

Correction

In notice document 2012–12042 appearing on page 29697 in the issue of Friday, May 18, 2012, make the following correction:

On page 29697, in the second column, in the ninth paragraph, the first line should read ''Submit, by July 17, 2012, comments that address the following questions:''

[FR Doc. C1–2012–12042 Filed 5–30–12; 8:45 am]

BILLING CODE 1505–01–D

NUCLEAR REGULATORY COMMISSION

[Docket No. 40–9086; NRC–2010–0143]

Safety Evaluation Report, International Isotopes Fluorine Products, Inc., Fluorine Extraction Process and Depleted Uranium Deconversion Plan, Lea County, NM

AGENCY: Nuclear Regulatory Commission.

ACTION: Notice of availability.

SUMMARY: The U.S. Nuclear Regulatory Commission (NRC or the Commission) is considering the issuance of a license to International Isotopes Fluorine Products, Inc., (IIFP or the applicant) to authorize construction and operations of a depleted uranium deconversion facility and possession and use of source material. This proposed facility is known as the Fluorine Extraction Process and Depleted Uranium Deconversion Plant (FEP/DUP) and will be located in Lea County, New Mexico. The NRC has prepared a Safety Evaluation Report (SER) in support of this license application review (NUREG–2116).

ADDRESSES: Please refer to Docket ID NRC–2010–0143 when contacting the NRC about the availability of information regarding this document. You may access information related to this document, which the NRC possesses and is publicly available using the following methods:

- *Federal Rulemaking Web site:* Go to *http://www.regulations.gov* and search for Docket ID NRC–2010–0143. Address questions about NRC dockets to Carol Gallagher; telephone: 301–492–3668; email: *Carol.Gallagher@nrc.gov*.
- *NRC's Agencywide Documents Access and Management System (ADAMS):* You may access publicly-available documents online in the NRC Library at *http://www.nrc.gov/reading-rm/adams.html.* To begin the search, select ''ADAMS Public Documents'' and then select ''*Begin Web-based ADAMS Search.''* For problems with ADAMS, please contact the NRC's Public Document Room (PDR) reference staff at 1–800–397–4209, 301–415–4737, or by email to *pdr.resource@nrc.gov*. The ADAMS accession number for each document referenced in this notice (if that document is available in ADAMS) is provided the first time that a document is referenced.
- *NRC's PDR:* You may examine and purchase copies of public documents at the NRC's PDR, Room O1–F21, One White Flint North, 11555 Rockville Pike, Rockville, Maryland 20852.

FOR FURTHER INFORMATION CONTACT: Matthew Bartlett, Project Manager, Conversion, Deconversion and Enrichment Branch, Division of Fuel Cycle Safety and Safeguards, Office of Nuclear Material Safety and Safeguards, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001; telephone: 301–492–3119; email: *Matthew.Bartlett@nrc.gov*.

SUPPLEMENTARY INFORMATION:

I. Introduction

By letter dated December 30, 2009, the applicant submitted to the NRC, an application requesting a license, under Title 10 of the Code of Federal Regulations (10 CFR) Part 40 to possess and use source material for a fluorine extraction and depleted uranium deconversion facility. The applicant proposes that the facility, known as the FEP/DUP, be located in Lea County, New Mexico, about 23 kilometers (14 miles) east of the city of Hobbs, New Mexico. By letter dated May 3, 2012, IIFP submitted an updated application incorporating information requested by the NRC staff during the application review, see ADAMS Accession Number ML12124a307.

The NRC staff has prepared the SER in support of this license application review. The SER discusses the results of the safety review performed by the staff in the following areas: General information, organization and administration, integrated safety analysis (ISA) and ISA summary, radiation protection, nuclear criticality safety, chemical process safety, fire safety, emergency management, environmental protection, decommissioning, management measures, quality assurance program description, physical protection, materials control and accountability, and human factors.

II. Further Information

The SER is available electronically at the NRC's Electronic Reading Room at *http://www.nrc.gov/reading-rm/adams.html.* From this site, you can access the NRC's ADAMS, which provides text and image files of NRC's public documents. The ADAMS Accession Number for the May 3, 2012, revised license application is ML12123a245. The ADAMS Accession Number for the May 22, 2012 SER is ML113140271.

If you do not have access to ADAMS or if there are problems in accessing the documents located in ADAMS, contact the NRC Public Document Room's (PDR's) reference staff at 800–397–4209, 301–415–4737 or via email to *pdr.resource@nrc.gov.*

These documents may also be viewed electronically on the public computers located at the NRC's PDR, O1–F21, One White Flint North, 11555 Rockville Pike, Rockville, Maryland 20852. The PDR reproduction contractor will copy documents for a fee.

Dated at Rockville, Maryland, this 22nd day of May 2012.

For the U.S. Nuclear Regulatory Commission.

Marissa Bailey,

Deputy Director, Division of Fuel Cycle Safety and Safeguards, Office of Nuclear Material Safety and Safeguards.

[FR Doc. 2012–13183 Filed 5–30–12; 8:45 am]

BILLING CODE 7590–01–P

OFFICE OF PERSONNEL MANAGEMENT

Excepted Service

AGENCY: U.S. Office of Personnel Management (OPM).

ACTION: Notice.

SUMMARY: This notice identifies Schedule A, B, and C appointing authorities applicable to a single agency that were established or revoked from February 1, 2012, to February 29, 2012.

FOR FURTHER INFORMATION CONTACT: Phyllis Proctor, Senior Executive Resource Services, Executive Resources and Employee Development, Employee Services, 202–606–2246.

SUPPLEMENTARY INFORMATION: In accordance with 5 CFR 213.103, Schedule A, B and C appointing authorities available for use by all agencies are codified in the Code of Federal Regulations (CFR). Schedule A, B and C appointing authorities applicable to a single agency are not codified in the CFR, but the Office of Personnel Management (OPM) publishes a notice of agency-specific authorities established or revoked each month in the **Federal Register** at *www.gpo.gov/fdsys/.* OPM also publishes annually a consolidated listing of all Schedule A, B and C appointing authorities current as of June 30 as a notice in the **Federal Register**.

Schedule A

No Schedule A authorities to report during February 2012.

Schedule B

The following Schedule B authorities were reported during February 2012.

Section 213.3211. Department of Homeland Security

(a) Coast Guard.

(1) Up to 36 permanent positions at the GS–9 through GS–15 grade levels. This authority may be used to fill GS–080 (Security) and GS–132 (Intelligence) positions. No appointments may be made under this authority after April 30, 2012.

Schedule C

The following Schedule C appointing authorities were approved during February 2012.

Agency name	Organization name	Position title	Authorization number	Effective date
Department of Agriculture	Office of the Under Secretary for Research, Education, and Economics.	Chief of Staff	DA120032	2/7/2012
	Office of the Under Secretary for Marketing and Regulatory Programs.	Senior Advisor	DA120036	2/10/2012
	Office of the Under Secretary for Research, Education, and Economics.	Confidential Assistant	DA120037	2/10/2012
	Rural Housing Service	Special Assistant	DA120039	2/17/2012
	Rural Housing Service	Confidential Assistant	DA120034	2/24/2012
Department of Commerce	Office of the Under Secretary	Senior Advisor	DC120040	2/2/2012
	Office of the Under Secretary	Senior Policy Advisor	DC120072	2/14/2012
	Office of Public Affairs	Senior Advisor for Communications and Policy.	DC120073	2/16/2012
	Office of Public Affairs	Director of Digital Strategy	DC120070	2/24/2012
Department of the Army	Office Deputy Under Secretary of Army (Operations Research).	Special Assistant	DW120015	2/22/2012
	Office Assistant Secretary Army (Manpower and Reserve Affairs).	Special Assistant(Manpower and Reserve Affairs).	DW120014	2/24/2012
Department of the Navy	Office of the Secretary	Special Assistant	DN120011	2/2/2012
Department of Education	Office of the General Counsel	Special Counsel	DB120043	2/2/2012
	Office of the General Counsel	Special Counsel	DB120045	2/2/2012
	Office of the General Counsel	Senior Counsel	DB120044	2/7/2012
	Office of the Secretary	Deputy White House Liaison	DB120052	2/10/2012
	Office of the General Counsel	Chief of Staff	DB120053	2/23/2012
	Office of Legislation and Congressional Affairs.	Special Assistant	DB120054	2/23/2012
	Office of Innovation and Improvement.	Senior Counsel	DB120055	2/24/2012
	Office of the Secretary	Confidential Assistant	DB120056	2/24/2012
General Services Administration	Office of the Administrator	Special Assistant	GS120009	2/28/2012
	Office of Administrative Services	Special Advisor	GS120010	2/28/2012
Department of Health and Human Services.	Office of the Secretary	Confidential Assistant	DH120046	2/7/2012
	Office of the Secretary	Senior Advisor	DH120047	2/14/2012
	Office of the Secretary	Advance Lead	DH120043	2/16/2012
	Office of the Secretary	Advance Lead	DH120044	2/16/2012
	Office of the Deputy Secretary	Chief of Staff	DH120045	2/16/2012
	Office of the Secretary	Deputy White House Liaison for Political Personnel, Boards and Commissions.	DH120052	2/16/2012
	Office of the Assistant Secretary for Planning and Evaluation.	Senior Policy Analyst	DH120053	2/16/2012
Department of Homeland Security	Office of the Secretary	Confidential Assistant	DM120061	2/9/2012
	Office of the Assistant Secretary for Public Affairs.	Public Affairs Specialist and Strategic Communication Coordinator.	DM120064	2/10/2012
	Office of the Assistant Secretary for Policy.	Executive Assistant	DM120066	2/13/2012
Department of Housing and Urban Development.	Office of the Secretary	Special Assistant	DU120022	2/8/2012
	Office of the Secretary	Director of Advance	DU120021	2/28/2012
Department of Justice	Antitrust Division	Senior Counsel	DJ120028	2/22/2012
Department of Labor	Office of the Secretary	Special Assistant	DL120027	2/17/2012

Agency name	Organization name	Position title	Authorization number	Effective date
	Office of Federal Contract Compliance Programs.	Special Assistant	DL120030	2/17/2012
	Office of Congressional and Intergovernmental Affairs.	Regional Representative	DL120031	2/24/2012
National Aeronautics and Space Administration.	Office of Legislative and Intergovernmental Affairs.	Legislative Affairs Specialist	NN120013	2/1/2012
	Office of Legislative and Intergovernmental Affairs.	Legislative Affairs Specialist	NN120010	2/23/2012
Office of Management and Budget	Communications	Deputy Associate Director for Strategic Planning and Communications.	BO110036	2/9/2012
	Office of Management and Budget	Confidential Assistant	BO120013	2/16/2012
Office of Personnel Management	Office of Communications and Public Liaison.	Speechwriter	PM120011	2/7/2012
Small Business Administration	Office of the Administrator	Senior Policy Advisor	SB120011	2/14/2012
Department of State	Office of the Chief of Protocol	Senior Protocol Officer	DS120022	2/7/2012
Department of Transportation	Administrator	Director for Governmental Affairs	DT120032	2/8/2012
Department of the Treasury	Assistant Secretary (Public Affairs)	Spokesperson	DY120059	2/7/2012
	Assistant Secretary (Public Affairs)	Senior Advisor	DY120062	2/16/2012
	Under Secretary for International Affairs.	Senior Advisor	DY120064	2/22/2012
United States International Trade Commission.	Office of the Chairman	Staff Assistant	TC120003	2/1/2012
	Office of the Chairman	Staff Assistant (Legal)	TC120004	2/1/2012

The following Schedule C appointing authorities were revoked during February 2012.

Agency	Organization	Position title	Authorization number	Vacate date
Department of Agriculture	Office of the Assistant Secretary for Congressional Relations.	Staff Assistant	DA110007	2/11/2012
	Foreign Agricultural Service	Senior Advisor	DA090206	2/24/2012
Department of Commerce	Office of the Chief of Staff	Director of Scheduling	DC100065	2/3/2012
	International Trade Administration	Senior Advisor	DC100076	2/10/2012
	Office of the Under Secretary	Director, Office of Legislative Affairs and Senior Trade Advisor.	DC110007	2/13/2012
	Office of Public Affairs	New Media Director	DC100127	2/25/2012
	Deputy Assistant Secretary for Domestic Operations.	Special Assistant	DC100078	2/29/2012
Department of Education	Office of the General Counsel	Chief of Staff	DB090106	2/11/2012
	Office of the General Counsel	Special Assistant	DB110048	2/11/2012
	Office of the General Counsel	Special Assistant	DB110088	2/11/2012
	Office for Civil Rights	Senior Counsel	DB120012	2/16/2012
	Office of the Secretary	Director, Scheduling and Advance Staff.	DB120034	2/16/2012
Department of Energy	Office of the Secretary	Deputy White House Liaison	DE100022	2/25/2012
Department of Health and Human Services.	Office of the Assistant Secretary for Legislation.	Special Assistant to the Deputy Assistant Secretary for Legislation.	DH090229	2/20/2012
Department of Homeland Security	Federal Emergency Management Agency.	Director of Public Affairs	DM120024	2/3/2012
	Office of the Assistant Secretary for Public Affairs.	Public Affairs and Strategic Communications Assistant.	DM110163	2/11/2012
	United States Customs and Border Protection.	Executive Assistant	DM090454	2/25/2012
Department of the Navy	Office of the Secretary	Special Assistant	DN110007	2/11/2012
	Office of the Under Secretary of the Navy.	Attorney Advisor	DN090078	2/18/2012
Environmental Protection Agency	Office of the Administrator	White House Liaison	EP100044	2/4/2012
Small Business Administration	Office of the Administrator	Policy Associate	SB100027	2/7/2012

Authority: 5 U.S.C. 3301 and 3302; E.O. 10577, 3 CFR 1954–1958 Comp., p. 218.

U.S. Office of Personnel Management.

John Berry,

Director.

[FR Doc. 2012–13137 Filed 5–30–12; 8:45 am]

BILLING CODE 6325–39–P

OFFICE OF PERSONNEL MANAGEMENT

Excepted Service

AGENCY: U.S. Office of Personnel Management (OPM).

ACTION: Notice.

SUMMARY: This gives notice of OPM decisions granting authority to make appointments under Schedules A, B, and C in the excepted service as required by 5 CFR 213.103.

FOR FURTHER INFORMATION CONTACT: Senior Executive Resource Services, Executive Resources and Employee Development, Employee Services, 202–606–2246.

SUPPLEMENTARY INFORMATION: Appearing in the listing below are the individual authorities established or revoked under Schedules A, B, and C between January 1, 2012, and January 31, 2012. These notices are published monthly in the **Federal Register** at *www.gpoaccess.gov/fr/*. A consolidated listing of all authorities as of June 30 is also published each year. The following Schedules are *not* codified in the Code of Federal Regulations. These are agency-specific exceptions.

Schedule A

No Schedule A authorities to report during January 2012.

Schedule B

No Schedule B authorities to report during January 2012.

Schedule C

The following Schedule C appointments were approved during January 2012.

Agency name	Organization name	Position title	Authorization number	Effective date
Department of Agriculture	Office of the Under Secretary for Rural Development.	Director, Legislative and Public Affairs Staff.	DA120022	1/17/2012
	Office of the Assistant Secretary for Congressional Relations.	Staff Assistant (Legislative Analyst)	DA120024	1/17/2012
	Office of the Assistant Secretary for Congressional Relations.	Staff Assistant	DA120021	1/24/2012
	Rural Housing Service	Chief of Staff	DA120025	1/24/2012
	Rural Utilities Service	Special Assistant	DA120026	1/24/2012
	Agricultural Marketing Service	Chief of Staff	DA120029	1/24/2012
Department of Commerce	National Oceanic and Atmospheric Administration.	Senior Policy Advisor	DC120036	1/5/2012
	Office of White House Liaison	Special Assistant	DC120039	1/5/2012
	Assistant Secretary for Market Access and Compliance.	Special Advisor	DC120038	1/9/2012
	Office of Public Affairs	Confidential Assistant	DC120051	1/9/2012
	Office of Public Affairs	Deputy Press Secretary	DC120042	1/11/2012
	Office of Assistant Secretary for Legislative and Intergovernmental Affairs.	Legislative Assistant	DC120043	1/11/2012
	Office of the Deputy Secretary	Special Assistant	DC120050	1/11/2012
	Office of Business Liaison	Special Assistant	DC120052	1/13/2012
	Office of the Chief of Staff	Special Assistant	DC120053	1/17/2012
	Office of Public Affairs	Director of Speechwriting	DC120055	1/20/2012
	Office of Executive Secretariat	Confidential Assistant	DC120057	1/25/2012
	Office of Legislative and Intergovernmental Affairs.	Confidential Assistant	DC120044	1/26/2012
Commission on Civil Rights Council on Environmental Quality Department of Defense.	Commissioners	Special Assistant	CC120002	1/26/2012
	Council on Environmental Quality	Special Assistant	EQ120001	1/12/2012
	Office of the Secretary	Advance Officer	DD120019	1/5/2012
	Deputy Under Secretary of Defense (Logistics and Materiel Readiness).	Confidential Assistant	DD120020	1/5/2012
	Office of the Under Secretary of Defense (Policy).	Special Assistant (Homeland Defense and Americas' Security Affairs).	DD120022	1/5/2012
	Office of the Secretary	Advance Officer	DD120018	1/6/2012
	Office of Assistant Secretary of Defense (Public Affairs).	Assistant Press Secretary	DD120023	1/12/2012
	Office of the Secretary	Confidential Assistant	DD120025	1/12/2012
	Office of Assistant Secretary of Defense (Public Affairs).	Research Assistant	DD120026	1/12/2012
Department of Education	Office of the Secretary	Director, Scheduling and Advance Staff.	DB120034	1/6/2012
	Office of the Under Secretary	Director, White House Initiative on Educational Excellence for Hispanic Americans.	DB120027	1/20/2012
	Office of Communications and Outreach.	Special Assistant	DB120046	1/27/2012
	Office of the Secretary	Special Assistant	DB120048	1/27/2012

Agency name	Organization name	Position title	Authorization number	Effective date
	Office of the Under Secretary	Deputy Director, White House Initiative on Educational Excellence for Hispanic Americans.	DB120049	1/27/2012
Department of Energy	Office of Public Affairs	Speechwriter	DE120035	1/20/2012
	Office of Public Affairs	Communications Coordinator	DE120037	1/20/2012
Department of Health and Human Services.	Office of the Assistant Secretary for Public Affairs.	Senior Advisor	DH120038	1/26/2012
	Office of the Commissioner	Senior Advisor	DH120037	1/27/2012
Department of Homeland Security	Office of the Assistant Secretary for Policy.	Policy Analyst	DM120039	1/3/2012
	Office of the Under Secretary for National Protection and Programs Directorate.	Cybersecurity Strategist	DM120050	1/17/2012
Department of Housing and Urban Development.	Office of Public Affairs	Assistant Press Secretary	DU120023	1/9/2012
Department of the Interior	Secretary's Immediate Office	Trip Director	DI120025	1/23/2012
	Secretary's Immediate Office	Special Assistant	DI120023	1/26/2012
	Office of the Solicitor	Counselor	DI120026	1/27/2012
Department of Justice	Antitrust Division	Chief of Staff and Counsel	DJ120018	1/4/2012
	Civil Division	Senior Counsel	DJ120021	1/12/2012
	National Security Division	Counsel	DJ120024	1/30/2012
Department of Labor	Office of Public Affairs	Special Assistant	DL120023	1/13/2012
Small Business Administration	Office of Communications and Public Liaison.	Deputy Assistant Administrator for Communications and Public Liaison.	SB120009	1/6/2012
Department of State	Bureau of Public Affairs	Senior Advisor	DS120020	1/12/2012
Department of Transportation	Immediate Office of the Administrator.	Associate Administrator for Governmental, International, and Public Affairs.	DT120017	1/3/2012
	Office of Congressional Affairs	Associate Director of Congressional Affairs.	DT120019	1/3/2012
	Assistant Secretary for Transportation Policy.	Deputy Director for Public Engagement.	DT120025	1/13/2012
	Public Affairs	Deputy Director of Public Affairs	DT120023	1/17/2012
	Assistant Secretary for Transportation Policy.	Associate Director for Transportation Policy.	DT120024	1/17/2012
	Associate Administrator for Public Affairs.	Associate Administrator for Communications and Legislative Affairs.	DT120018	1/26/2012
	Public Affairs	Press Secretary	DT120026	1/26/2012
	Secretary	Advance Specialist	DT120027	1/26/2012
Department of the Treasury	Secretary of the Treasury	Deputy Executive Secretary	DY120057	1/26/2012

The following Schedule C appointing authorities were revoked during January 2012.

Agency	Organization	Position title	Authorization number	Effective date
Department of Agriculture	Rural Housing Service	Special Assistant to the Administrator.	DA100116	1/28/2012
	Risk Management Agency	Confidential Assistant	DA100162	1/28/2012
	Food Safety and Inspection Service.	Senior Advisor	DA100176	1/28/2012
Department of Commerce	Office of Under Secretary	Special Assistant	DC090182	1/7/2012
	Office of Public Affairs	Deputy Director for Public Affairs	DC110118	1/13/2012
Department of Commerce	Office of Executive Secretariat	Confidential Assistant	DC100129	1/14/2012
	Department of Commerce	Confidential Assistant	DC100077	1/23/2012
	Office of the Chief of Staff	Confidential Assistant	DC100120	1/28/2012
Department of Education	Office of the Under Secretary	Deputy Director, White House Initiative on Educational Excellence for Hispanic Americans.	DB110083	1/28/2012
Department of Energy	Assistant Secretary for Energy Efficiency and Renewable Energy.	Special Assistant	DE090182	1/4/2012
	Office of Public Affairs	New Media Specialist	DE090115	1/20/2012
Department of Homeland Security	Office of Operations Coordination and Planning Directorate.	Special Assistant to the Chief of Staff.	DM090379	1/4/2012
	Office of the Assistant Secretary for Public Affairs.	Deputy Assistant Secretary for Strategic Communications.	DM110031	1/10/2012

Agency	Organization	Position title	Authorization number	Effective date
	Office of the Assistant Secretary for Policy.	Policy Analyst	DM110238	1/13/2012
	Office of the Assistant Secretary for Public Affairs.	Deputy Press Secretary	DM110252	1/20/2012
Department of Housing and Urban Development.	Office of Public Affairs	General Deputy Assistant Secretary for Public Affairs.	DU090079	1/14/2012
	Office of Policy Development and Research.	Deputy Assistant Secretary for policy Development.	DU090070	1/14/2012
	Office of Public Affairs	Press Assistant	DU100110	1/14/2012
Department of Justice	Antitrust Division	Counsel	DJ100163	1/14/2012
	Environment and Natural Resources Division.	Counsel and Chief of Staff	DJ100067	1/21/2012
Department of Labor	Office of the Secretary	Special Assistant	DL110044	1/14/2012
Department of the Interior	Secretary's Immediate Office	Special Assistant	DI110050	1/22/2012
Department of the Treasury	Secretary of the Treasury	Deputy Executive Secretary	DY110060	1/27/2012
Department of Transportation	Public Affairs	Deputy Director of Public Affairs	DT090095	1/13/2012
	Secretary	Special Assistant	DT090115	1/16/2012
	Administrator	Director, Office of Congressional and Public Affairs.	DT100042	1/16/2012
	Public Affairs	Deputy Press Secretary	DT100006	1/28/2012
Office of the Secretary of Defense	Office of the Secretary	Personal and Confidential Assistant.	DD090099	1/14/2012
	Office of the Secretary	Confidential Assistant	DD090197	1/14/2012
	Washington Headquarters Services	Defense Fellow	DD110056	1/14/2012
	Office of Assistant Secretary of Defense (Public Affairs).	Special Assistant	DD100134	1/16/2012
Small Business Administration	Office of Communications and Public Liaison.	Press Secretary	SB090043	1/14/2012
	Office of Communications and Public Liaison.	Speechwriter	SB090037	1/21/2012
	Office of Communications and Public Liaison.	Press Assistant	SB100002	1/27/2012
Trade and Development Agency	Office of the Director	Chief of Staff	TD100001	1/6/2012

Authority: 5 U.S.C. 3301 and 3302; E.O. 10577, 3 CFR 1954–1958 Comp., p. 218.

U.S. Office of Personnel Management.

John Berry,

Director.

[FR Doc. 2012–13138 Filed 5–30–12; 8:45 am]

BILLING CODE 6325–39–P

POSTAL SERVICE

Sunshine Act Meeting; Board of Governors

DATES AND TIMES: Thursday, June 14, 2012, at 10 a.m.

PLACE: Washington, DC, at U.S. Postal Service Headquarters, 475 L'Enfant Plaza SW., in the Benjamin Franklin Room.

STATUS: Closed.

MATTERS TO BE CONSIDERED:

Thursday, June 14, at 10:00 a.m. (Closed)

1. Strategic Issues.
2. Financial Matters.
3. Pricing.
4. Personnel Matters and Compensation Issues.
5. Governors' Executive Session—Discussion of prior agenda items and Board Governance.

CONTACT PERSON FOR MORE INFORMATION: Julie S. Moore, Secretary of the Board, U.S. Postal Service, 475 L'Enfant Plaza, SW., Washington, DC 20260–1000. Telephone (202) 268–4800.

Julie S. Moore,

Secretary.

[FR Doc. 2012–13377 Filed 5–29–12; 4:15 pm]

BILLING CODE 7710–12–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–67053; File No. SR–Phlx–2012–71]

Self-Regulatory Organizations; NASDAQ OMX PHLX LLC; Notice of Filing and Immediate Effectiveness of Proposed Rule Change To Amend Rule 616, Electronic Filing Requirements for Uniform Forms

May 24, 2012.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act''),[1] and Rule 19b–4 [2] thereunder, notice is hereby given that on May 18, 2012, NASDAQ OMX PHLX LLC (''Phlx'' 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 prepared by the Exchange. The Exchange filed the proposal as a ''non-controversial'' proposed rule change pursuant to Section 19(b)(3)(A)(iii) of the Act [3] and Rule 19b–4(f)(6) thereunder,[4] which renders the proposal effective upon receipt of this filing by the Commission. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The Exchange proposes to amend Rule 616, Electronic Filing Requirements for Uniform Forms.

The text of the proposed rule change is available on the Exchange's Web site at *http://www.nasdaqtrader.com/micro.aspx?id=PHLXRulefilings,* at the principal office of the Exchange, and at the Commission's Public Reference Room.

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] 15 U.S.C. 78s(b)(3)(A)(iii).

[4] 17 CFR 240.19b–4(f)(6).

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the Exchange included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in sections A, B, and C below, of the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

The purpose of the proposed rule change is to correct Rule 616 to correspond to amended Equity Floor Procedure Advice (''EFPA'') A–7 and Options Floor Procedure Advice (''OFPA'') F–34 (together, the ''Advices'').[5]

Recently, the Exchange adopted Rule 616, Electronic Filing Requirements for Uniform Forms, to provide that forms required to be filed under the Rule 600 Series shall be filed electronically through WebCRD and initial filings and amendments of Forms U4 and U5 be submitted electronically.[6] Furthermore, as part of the member organization's recordkeeping requirements, Rule 616 requires that it shall retain such records for a period of not less than three years, the first two years in an easily accessible place, in accordance with Rule 17a–4 under the Act,[7] and make such records available promptly upon regulatory request. In addition, every application for registration filed with the Exchange shall be kept current at all times by supplementary amendments via electronic filing or such other process as the Exchange may prescribe. Such amendments shall be filed not later than 30 days after the applicant learns of the facts or circumstances giving rise to the need for the amendment.

The Exchange also amended OFPA F–34 and EFPA A–7, both titled Failure to Timely Submit Amendments to Form U4, Form U5 and Form BD, to add various new rule numbers, including Rule 616. Each provides that any member, and member organization that is required to file Form U4, Form U5 or Form BD pursuant to Exchange Rules 600, 611–613, 616, or 620, or the Act and the rules promulgated thereunder, is required to amend the applicable Form U4, Form U5 or Form BD to keep such forms current at all times. Members, and member organizations must amend Form U4, Form U5 or Form BD not later than thirty (30) days after the filer knew or should have known of the facts which gave rise to the need for the amendment.

When adopting Rule 616, the language ''or should have known of'' was omitted from the rule, although it appears in the Advices. As a result, a member who should have known of the facts which gave rise to the need for an amendment to a Form U4, Form U5 or a Form BD could be violating the Advice, but not Rule 616. Because Rule 616 was intended to codify the electronic filing requirements into a single rule, the Exchange believes it is preferable for the rule language to better match the Advice language.

2. Statutory Basis

The Exchange believes that its proposal is consistent with Section 6(b) of the Act[8] in general, and furthers the objectives of Section 6(b)(5) of the Act[9] in particular, in that it is designed to promote just and equitable principles of trade, to remove impediments to and perfect the mechanism of a free and open market and a national market system, and, in general to protect investors and the public interest, by ensuring that the Exchange's rules are clear.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange does not believe that the proposed rule change will impose any burden on competition not necessary or appropriate in furtherance of the purposes of the Act.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

No written comments were either solicited or received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

Because the foregoing proposed rule change does not: (i) Significantly affect the protection of investors or the public interest; (ii) impose any significant burden on competition; and (iii) become operative for 30 days after the date of the filing, or such shorter time as the Commission may designate, it has become effective pursuant to Section 19(b)(3)(A) of the Act[10] and Rule 19b–4(f)(6)[11] thereunder.

At any time within 60 days of the filing of the proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act. If the Commission takes such action, the Commission shall institute proceedings to determine whether the proposed rule should be approved or disapproved.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send an email to *rule-comments@sec.gov.* Please include File Number SR–Phlx–2012–71 on the subject line.

Paper Comments

- Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–Phlx–2012–71. This file

[5] The Advices are administered pursuant to the Exchange's minor rule violation plan, which specifies those uncontested minor rule violations with sanctions not exceeding $2,500 that would not be subject to the provisions of Rule 19d–1(c)(1) under the Act. Rule 19d–1(c) allows SROs to submit for Commission approval plans for the abbreviated reporting of minor disciplinary infractions. Any disciplinary action taken by an SRO against any person for violation of a rule of the SRO which has been designated as a minor rule violation pursuant to such a plan will not be considered ''final'' for purposes of Section 19(d)(1) of the Act if the sanction imposed consists of a fine not exceeding $2,500 and the sanctioned person has not sought an adjudication, including a hearing, or otherwise exhausted his administrative remedies. *See* 17 CFR 240.19d–1(c)(1).

[6] *See* Securities Exchange Act Release No. 66840 (April 20, 2012), 77 FR 25003 (April 26, 2012) (SR–Phlx–2012–23).

[7] 17 CFR 240.17a–4.

[8] 15 U.S.C. 78f(b).

[9] 15 U.S.C. 78f(b)(5).

[10] 15 U.S.C. 78s(b)(3)(A).

[11] 17 CFR 240.19b–4(f)(6). In addition, Rule 19b–4(f)(6) requires a self-regulatory organization to give the Commission written notice of its intent to file the proposed rule change at least five business days prior to the date of filing of the proposed rule change, or such shorter time as designated by the Commission. The Exchange has satisfied this requirement.

number should be included on the subject line if email is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet 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 Web site viewing and printing in the Commission's Public Reference Room, 100 F Street NE., Washington, DC 20549, on official business days between the hours of 10 a.m. and 3 p.m. Copies of the filing also will be available for inspection and copying at the principal office of the Exchange. 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–Phlx–2012–71 and should be submitted on or before June 21, 2012.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[12]

Kevin M. O'Neill,

Deputy Secretary.

[FR Doc. 2012–13085 Filed 5–30–12; 8:45 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–67059; File No. SR–FICC–2012–04]

Self-Regulatory Organizations; Fixed Income Clearing Corporation; Notice of Filing of Proposed Rule Change To Clarify the Ability of the Government Securities Division To Use Implied Volatility Indicators as Part of the Volatility Model in Its Clearing Fund Formula

May 24, 2012.

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 May 15, 2012, Fixed Income Clearing Corporation ("FICC") filed with the Securities and Exchange Commission ("Commission") the proposed rule change as described in Items I and II below, which Items have been prepared primarily by FICC. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The Government Securities Division ("GSD") of FICC proposes to amend the definition of VaR Charge in Rule 1 to clarify the ability of FICC GSD to use implied volatility indicators as part of the volatility model in its clearing fund formula.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, FICC 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. FICC has prepared summaries, set forth in sections (A), (B), and (C) below, of the most significant aspects of these statements.[3]

(A) Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

A primary objective of GSD's Clearing Fund[4] is to have on deposit from each applicable Member[5] assets sufficient to satisfy losses that may otherwise be incurred by GSD as the result of the default of the Member and the resultant close out of that Member's unsettled positions under GSD's trade guaranty. The required Clearing Fund deposit of each Member is calculated twice daily[6] pursuant to a formula set forth in Section 1b of GSD Rule 4 designed to provide sufficient funds to cover this risk of loss. The Clearing Fund formula accounts for a variety of risk factors through the application of a number of components, each described in Section 1b of GSD Rule 4.

The volatility component of the Clearing Fund formula is designed to calculate the amount of money that may be lost on a portfolio over a given period of time assumed necessary to liquidate the portfolio within a given level of confidence. Pursuant to Section 1b of Rule 4, GSD may calculate the volatility component on a value at risk charge ("VaR Charge") "utilizing such assumptions (including confidence levels) and based on such historical data as [GSD] deems reasonable, and shall cover such range of historical volatility as [GSD] from time to time deems appropriate."[7] FICC believes that Section 1b of Rule 4 therefore provides GSD with the flexibility to adjust the calculation of the volatility component of its Clearing Fund formula as needed to react to changes in market conditions, including through the use of such assumptions and data as it deems appropriate within its VaR Charge.

The historical simulation model currently used to calculate the VaR Charge in GSD's Clearing Fund formula is driven by historical data observed in the fixed-income market. While the model weighs the data it uses in favor of more recent observations, it is still limited in its ability to quickly reflect sudden changes in market volatility, which may lead to the collection of insufficient margin during periods of sudden market volatility.

GSD's Clearing Fund formula, in particular the VaR Charge, provides GSD with the discretion to adjust the model assumptions and data as necessary to react to these market conditions. To enhance the model's performance, additional information and other observable market data, including data derived from financial products with future maturity dates, thus may be incorporated into or utilized by the volatility model, including data observed in implied volatility indicators that are derived from historical prices of financial products that have maturity dates in the future (such as the 1-year option on the 10-year swap rate). For the avoidance of doubt, this proposed rule change would amend the definition of VaR Charge to make clear that the assumptions and data utilized in calculating the VaR Charge may be based on observable market data, which may include

[12] 17 CFR 200.30–3(a)(12).

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] The Commission has modified the text of the summaries prepared by FICC.

[4] FICC GSD Rule 1—Definitions provides that "[t]he term 'Clearing Fund' means the Clearing Fund established by the Corporation pursuant to these Rules, which shall be comprised of the aggregate of all Required Fund Deposits and all other deposits, including Cross-Guaranty Repayment Deposits, to the Clearing Fund."

[5] FICC GSD Rule 1—Definitions provides that "[t]he term 'Member' means a Comparison-Only Member or a Netting Member. The term 'Member' shall include a Sponsoring Member in its capacity as a Sponsoring Member and a Sponsored Member, each to the extent specific in Rule 3A."

[6] A Member's Clearing Fund deposit may also be recalculated on an intraday basis as needed.

[7] FICC GSD Rule 1—Definitions defining the term VaR Charge in relevant part.

implied market volatility indicators that are derived from historical prices of financial products that have maturity dates in the future, so as to enhance the performance of the model and enable GSD to more effectively achieve and maintain the confidence level required by regulatory and industry standards.[8] Incorporation of such information into volatility calculations is a generally accepted practice for portfolio volatility models, currently used by other clearing agencies, and accordingly consistent with current rules of FICC.

GSD reviews its risk management processes against applicable regulatory and industry standards, including, but not limited to: (i) the Recommendations for Central Counterparties (''RCCP'') of the Committee on Payment and Settlement Systems and the Technical Committee of the International Organization of Securities Commissions (''CPSS–IOSCO'') and (ii) the securities laws of the United States and rules promulgated by the Commission.

CPSS–IOSCO RCCP Recommendation 4: Margin requirements recommends that a central counterparty (''CCP'') should maintain sufficient financial resources to cover potential exposures in normal market conditions.[9] It also recommends that margin models and parameters should be regularly reviewed and back-tested to ensure a 99% coverage level is maintained.

CPSS–IOSCO Recommendation 3: Measurement and management of credit exposures recognizes the need for flexibility in the models underlying the calculation of margin requirements. To this point, the explanatory note to RCCP Recommendation 3 recognizes that, ''[t]he appropriate amount of data to use [in a CCP's margin formula] will vary from market to market and over time. If, for example, volatility rises, a CCP may want to use a short interval that better captures the new, higher volatility prevailing in its markets.'' [10] Similarly, the Commission proposed Rule 17Ad–22(b)(2) which addresses the margin requirements of a clearing agency that performs CCP services and would require those clearing agencies to establish, implement, maintain and enforce written policies and procedures reasonably designed to use margin requirements to limit credit exposures to participants in normal market conditions and use risk-based models and parameters to set margin requirements and review them at least monthly.[11] The Commission release that proposed Rule 17Ad–22(b)(2) states, ''[m]arket conditions and risks are constantly changing and therefore the models and parameters used by a clearing agency providing CCP services to set margin may not accurately reflect the needs of a clearing agency if they are permitted to remain static.'' [12]

FICC believes that this proposed rule change would clarify that GSD at its discretion may utilize implied volatility indicators that are derived from historical prices of financial products that have maturity dates in the future among the assumptions and other observable market data as part of its volatility model. The proposal would also clarify the ability of GSD to adjust its volatility calculations as needed to improve the performance of the model in periods of market volatility. It would therefore assist GSD to maintain the requisite confidence level notwithstanding those market conditions. As such, FICC believes that it conforms to CPSS–IOSCO Recommendations 3 and 4, Commission proposed Rule 17Ad–22(b)(2), and Commission proposed Rule 17Ad–22(b)(1).[13]

As an example of one such adjustment to the volatility model, GSD plans to apply a multiplier (the augmented volatility adjustment multiplier) to the VaR Charge. The multiplier is based on the levels of change in current and implied volatility measures. An advantage of this approach is that as volatility subsides in the market so will the effect of the multiplier on Members' margin requirements. The volatility measures will be determined by reference to the implied volatility of the 1-year option on the 10-year USD LIBOR swap rate and the historical volatility of the 10-year USD LIBOR swap rate. It is expected that GSD will provide its Members with advance notice of the multiplier that may be applied to the Members' VaR Charge on a weekly basis.[14] By using a single fixed multiplier based on observable market data, Members will be able to predict the impact on their margin requirement. *Although the augmented volatility adjustment multiplier will be automatically applied to each Member's VaR Charge, GSD may in its sole discretion determine to waive the application of the multiplier to all of its Members in circumstances it deems warrant such a waiver.*[15]

FICC intends that this proposed rule change would be effective on a date no less than ten business days following an Important Notice to Members by FICC announcing any approval by the Commission.

As a clearing agency that performs CCP services, FICC GSD believes that it occupies an important role in the securities settlement system by interposing itself between counterparties to financial transactions and thereby reducing risks faced by participants and contributing to global financial stability. FICC believes that the effectiveness of a CCP's risk controls and the adequacy of its financial resources are critical to achieving these risk-reducing goals. FICC believes this proposed rule change would assist GSD in its efforts to ensure the efficacy of its volatility margin methodology in highly volatile markets and, thereby, should reduce GSD's and its Members' exposure to the losses of a defaulting Member.

FICC believes the proposed change is consistent with Section 17A of the Act [16] and the rules and regulations thereunder because the proposed modifications would help assure the safeguarding of securities and funds which are in the custody or control of FICC or for which it is responsible by clarifying that FICC GSD's rules permit it to use implied volatility indicators that are derived from historical prices of financial products that have maturity dates in the future as part of the volatility model in its Clearing Fund formula.

[8] The text of the proposed change to the definition of VaR Charge can be found in Exhibit 5 to proposed rule change SR–FICC–2012–04 at *http://www.dtcc.com/downloads/legal/rule_filings/2012/ficc/SR–FICC–2012–04.pdf.*

[9] Normal market conditions is defined in Explanatory Note to RCCP Recommendation 3 as ''price movements that produce changes in exposures that are expected to breach margin requirements or other risk control mechanisms only 1% of the time.''

[10] Bank for International Settlements and International Organization of Securities Commissions, *Recommendations for Central Counterparties* (November 2004) *available at www.bis.org/publ/cpss61.pdf.*

[11] Exchange Act Release No. 34–64017 (March 3, 2011), 76 FR 11472 (March 16, 2011); File No. S7–08–11.

[12] *Id.*

[13] Commission proposed Rule 17Ad–22(b)(1) addresses the measurement and management of credit exposures by a clearing agency that performs CCP services and would require such a clearing agency to ''establish, implement, maintain and enforce written policies and procedures reasonably designed to measure its credit exposures to its participants at least once a day and limit its exposures to potential losses from defaults by its participants in normal market conditions so that the operations of the clearing agency would not be disrupted and non-defaulting participants would not be exposed to losses that they cannot anticipate or control.''

[14] FICC GSD will reserve the right to recalculate the multiplier more frequently than weekly in volatile market conditions.

[15] FICC GSD plans to apply a cap to the multiplier and initially the cap will be set at 2. FICC GSD will reserve the right to change the cap in its sole discretion.

[16] 15 U.S.C. 78q–1.

(B) Self-Regulatory Organization's Statement on Burden on Competition

FICC does not believe that the proposed rule change would impose any burden on competition.

(C) Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants or Others

Written comments on the proposed rule change have not yet been solicited or received.[17] FICC will notify the Commission of any other written comments received by FICC.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

Within 45 days of the date of publication of this notice in the **Federal Register** or within such longer period up to 90 days (i) as the Commission may designate 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 or disapprove the proposed rule change or

(B) Institute proceedings to determine whether the proposed rule change should be disapproved.

Electronic Comments

• Use the Commissions Internet comment form (*http://www.sec.gov/rules/sro.shtml*) or

Send an email to *rule-comments@sec.gov.* Please include File Number SR–FICC–2012–04 on the subject line.

Paper Comments

• Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–FICC–2012–04. This file number should be included on the subject line if email is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet 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 Web site viewing and printing in the Commission's Public Reference Section, 100 F Street NE., Washington, DC 20549, on official business days between the hours of 10 a.m. and 3 p.m. Copies of such filing also will be available for inspection and copying at the principal office of FICC and on FICC's Web site at *http://www.dtcc.com/downloads/legal/rule_filings/2012/ficc/SR-FICC-2012-04.pdf.*

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–FICC–2012–04 and should be submitted on or before June 21, 2012.

For the Commission by the Division of Trading and Markets, pursuant to delegated authority.[18]

Kevin M. O'Neill,

Deputy Secretary.

[FR Doc. 2012–13150 Filed 5–30–12; 8:45 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–67058; File No. SR–NYSEArca–2012–45]

Self-Regulatory Organizations; NYSE Arca, Inc.; Notice of Filing of Proposed Rule Change Amending Its Rules To Reflect the Merger of Archipelago Holdings, Inc. ("Archipelago Holdings"), An Intermediate Holding Company, Into and With NYSE Group, Inc. ("NYSE Group"), Thereby Eliminating Archipelago Holdings From the Ownership Structure of the Exchange

May 24, 2012.

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 May 14, 2012, NYSE Arca, Inc. ("Exchange" or "NYSE Arca") filed with the Securities and Exchange Commission ("Commission") the proposed rule change as described in Items I and II below, which Items have been prepared by the Exchange. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The Exchange proposes to proposes to amend its rules to reflect the merger of Archipelago Holdings, Inc. ("Archipelago Holdings"), an intermediate holding company, into and with NYSE Group, Inc. ("NYSE Group"), thereby eliminating Archipelago Holdings from the ownership structure of the Exchange. The text of the proposed rule change is available on the Exchange's Web site at *www.nyse.com,* at the principal office of the Exchange, and at the Commission's Public Reference Room.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the self-regulatory organization included statements concerning the purpose of, and basis for, the proposed rule change and discussed any comments it received on the proposed rule change. The text of those statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in sections A, B, and C below, of the most significant parts of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

The Exchange proposes to amend its rules to reflect the merger of Archipelago Holdings, an intermediate holding company, into and with NYSE Group, thereby eliminating Archipelago Holdings from the ownership structure of the Exchange.

Currently, NYSE Arca Holdings owns 100% of the equity interest of the Exchange. Archipelago Holdings owns 100% of the equity interest of NYSE Arca Holdings, and NYSE Group owns 100% of the equity interest of Archipelago Holdings. NYSE Euronext owns 100% of the equity interest of NYSE Group.

NYSE Euronext intends to merge Archipelago Holdings with and into NYSE Group, effective following

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[17] FICC originally raised the prospect of the multiplier to the VaR charge to members in Important Notice GOV014.12 on January 27, 2012, to which FICC received comments. The comments FICC received were: (i) That the Important Notice lacked key information, including a sample calculation and details surrounding the application of the multiplier; and (ii) whether the proposal would be detrimental to smaller firms. FICC notified the Commission of the substance of these comments.

[18] 17 CFR 200.30–3(a)(12).

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

approval of this proposed rule change. The reason for the merger is to eliminate an unnecessary intermediate holding company. Following the merger, the Exchange would continue to be 100% owned by NYSE Arca Holdings, which in turn would be 100% owned by NYSE Group, which in turn would be 100% owned by NYSE Euronext.

The Certificate imposes certain ownership and voting restrictions on the shares of NYSE Arca Holdings. Specifically, Article 9, Section 1(b)(i)(B) of the Certificate provides that for so long as NYSE Arca Holdings directly or indirectly controls the Exchange, no Person either alone or together with its Related Persons,[3] may own, directly or indirectly, of record or beneficially shares of the capital stock (whether common or preferred stock) of NYSE Arca Holdings constituting more than 40% of the outstanding shares of any class of capital stock of NYSE Arca Holdings unless the Board of Directors of NYSE Arca Holdings (the ''Board'') has adopted an amendment to the NYSE Arca Holdings Bylaws (the ''Bylaws'') waiving such a restriction. In connection with such amendment, the Board must adopt resolutions stating that such amendment will not impair the ability of the Exchange to carry out its functions and responsibilities under the Securities Exchange Act of 1934, as amended (the ''Act''), and the rules thereunder; is otherwise in the best interests of NYSE Arca Holdings, its stockholders, and the Exchange; and will not impair the ability of the Commission to enforce the Act. Such amendment is not effective until approved by the Commission. The Board also must find that no such Person or Related Person is subject to a statutory disqualification under Section 3(a)(39) of the Act. Similarly, Article 9, Section 1(c) of the Certificate provides that no Person, either alone or together with its Related Persons, may directly or indirectly vote more than 20% of the shares of NYSE Arca Holdings unless the Board adopts an amendment to its Bylaws waiving such a restriction and, in connection with such amendment, adopts resolutions and makes a determination with respect to statutory disqualification substantially the same as those described above for the ownership restriction. Article 9, Section 4 of the Certificate provides certain exceptions to these ownership and voting restrictions for Archipelago Holdings.

The Exchange proposes to amend the Bylaws of NYSE Arca Holdings as required by the Certificate; make further amendments to the Certificate, Bylaws, and other rules that would reflect the elimination of Archipelago Holdings from the Exchange's ownership structure; and delete duplicative or obsolete text. The proposed rule change otherwise would have no substantive impact on other rules of the Exchange, including those concerning the voting and ownership restrictions that currently apply to the Exchange and its affiliates.[4] The Board has adopted resolutions approving the proposed changes.[5]

First, the Exchange proposes to replace references to Archipelago Holdings in Article 9, Section 4 of the Certificate with references to NYSE Group. In addition, the Exchange proposes to delete the last sentence of that Section, which relates to certain voting and ownership restrictions that were put in place when the Exchange combined with the New York Stock Exchange in 2005 but have been superseded by other requirements.[6]

Second, the Exchange proposes to amend the Bylaws by adding a new Article 11 that sets forth the waiver of the ownership and voting restrictions, as required by the Certificate, solely for purposes of the contemplated merger. The Exchange also proposes to amend the Bylaws to change references to the Pacific Exchange, Inc. to NYSE Arca, Inc.; change references to PCX Holdings, Inc. to NYSE Arca Holdings; and delete Section 6.07, which contains an obsolete reference to trading in minimum lots.

Third, the Exchange proposes to delete NYSE Arca Options Rule 1.1(cc) and (gg), which set forth the definitions for Archipelago Holdings and Related Person, and to delete NYSE Arca Options Rule 3.4, which sets forth ownership and voting restrictions for Archipelago Holdings. Upon the elimination of Archipelago Holdings, NYSE Group would be the next holding company, and voting and ownership restrictions are currently set forth in its Second Amended and Restated Certificate of Incorporation of NYSE Group, Inc. (''NYSE Group Certificate'') in Article IV, Section 4(b). The term Related Person is not otherwise used in the NYSE Arca Options Rules.

Fourth, NYSE Arca Equities Rule 14.3(b) provides that all officers and directors of Archipelago Holdings shall be deemed to be officers and directors of the Exchange and NYSE Arca Equities for purposes of, and subject to oversight pursuant to, the Act. NYSE Arca Equities Rule 14.3(d) provides that Archipelago Holdings must maintain all books and records related to the Exchange within the United States. The Exchange proposes to delete this text and make a conforming change to NYSE Arca Equities Rule 14.3(c). Comparable provisions are already contained in NYSE Group's governing documents. Under Article IX of the NYSE Group Certificate, NYSE Group's directors and officers already are subject to the jurisdiction of the Commission, and under Article X, NYSE Group's books and records relating to the Exchange must be maintained within the United States.

Fifth, NYSE Arca Equities Rule 14.3(a), (e), and (f) contain references to Archipelago Securities, L.L.C. for which a short form, ''Archipelago,'' is used. For the avoidance of confusion, the Exchange proposes to amend that reference to be ''Arca Securities,'' which is the short form used for Archipelago Securities, L.L.C. in NYSE Arca Equities Rule 7.45(c).

Finally, the Exchange proposes to delete in its entirety the text of the Amended and Restated Certificate of Incorporation and the Bylaws of Archipelago Holdings because the company will no longer exist upon consummation of the merger and as such these documents will no longer be rules of the Exchange.

2. Statutory Basis

The proposed rule change is consistent with Section 6(b) of the Act,[7] in general, and furthers the objectives of Section 6(b)(5) of the Act,[8] in particular, in that it is designed to prevent fraudulent and manipulative acts and practices, to promote just and equitable principles of trade, to foster cooperation and coordination with persons engaged in facilitating transactions in securities, and to remove impediments to and perfect the mechanism of a free and open market and a national market system. Specifically, the proposed rule change would result in the Exchange's rules correctly reflecting its ownership structure without having any substantive impact on the Exchange's rules, including those concerning the voting and ownership restrictions that currently apply to the Exchange and its affiliates.

[3] The terms ''Person'' and ''Related Persons'' are defined in the Certificate.

[4] *See* Securities Exchange Act Release No. 55294 (Feb. 14, 2007), 72 FR 8046 (Feb. 22, 2007) (SR–NYSEArca–2007–05); *see also* Securities Exchange Act Release No. 55293 (Feb. 14, 2007), 72 FR 8033 (Feb. 22, 2007) (SR–NYSE–2006–120).

[5] *See* Exhibit 5F.

[6] *See supra* note 4.

[7] 15 U.S.C. 78f(b).

[8] 15 U.S.C. 78f(b)(5).

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange does not believe that the proposed rule change will impose any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

No written comments were solicited or received with respect to the proposed rule change.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

Within 45 days of the date of publication of this notice in the **Federal Register** or within such longer period (i) as the Commission may designate up to 90 days of such date if it finds such longer period to be appropriate and publishes its reasons for so finding or (ii) as to which the self-regulatory organization consents, the Commission will:

A. By order approve or disapprove 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 email to *rule-comments@sec.gov.* Please include File Number SR–NYSEArca–2012–45 on the subject line.

Paper Comments

• Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street, NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–NYSEArca–2012–45. This file number should be included on the subject line if email is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet 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 Web site viewing and printing in the Commission's Public Reference Room, 100 F Street, NE., Washington, DC 20549, on official business days between the hours of 10 a.m. and 3 p.m. Copies of the filing also will be available for inspection and copying at the principal office of the Exchange. 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–NYSEArca–2012–45 and should be submitted on or before June 21, 2012.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[9]

Kevin M. O'Neill,

Deputy Secretary.

[FR Doc. 2012–13149 Filed 5–30–12; 8:45 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–67057; File No. SR–NYSEAmex–2012–31]

Self-Regulatory Organizations; NYSE Amex LLC; Notice of Filing of Proposed Rule Change Defining a Primary Specialist in Each Options Class and Modifying the Specialist Entitlement Accordingly

May 24, 2012.

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 May 11, 2012, NYSE Amex LLC (the ''Exchange'' or ''NYSE Amex'') filed with the Securities and Exchange Commission (''Commission'') the proposed rule change as described in Items I and II below, which Items have been prepared by the self-regulatory organization. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The Exchange proposes to define a Primary Specialist in each options class and modify the Specialist entitlement accordingly. The text of the proposed rule change is available at the Exchange, the Commission's Public Reference Room, and *www.nyse.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, the self-regulatory organization included statements concerning the purpose of, and basis for, the proposed rule change and discussed any comments it received on the proposed rule change. The text of those statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in sections A, B, and C below, of the most significant parts of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

The Exchange proposes to amend Rules 964NY and 964.2NY to define Primary Specialists, and to modify the order allocation entitlement amongst Specialist Pool participants so as to enhance competition between the Specialist and e-Specialists.

Rule 964NY sets forth the priority for the allocation of incoming orders to resting interest at a particular price in the NYSE Amex System. Under the rule, resting Customer orders have first priority. After that, Directed Order Market Makers have second priority, provided they satisfy the criteria to be eligible to receive a Directed Order. If an order is not allocated to a Directed Order Market Maker, the Specialist Pool has next priority. As currently provided in Rule 964NY(b)(2)(C) and Rule 964.2NY, the Specialist and e-Specialists in each class compete in the Specialist Pool on a size pro-rata basis, and do not compete at all for the allocation of non-Directed Orders of five contracts or fewer.[3] For orders of five contracts or fewer, they are allocated on a rotating basis (i.e., a round robin) to a Specialist or e-Specialist in the

[9] 17 CFR 200.30–3(a)(12).

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] Under the rule, the Specialist's pro-rata allocation may receive additional weighting as determined by the Exchange.

Specialist Pool. After the Specialist Pool, non-Customer interest has next priority on a size pro-rata basis.

The Exchange proposes to enhance competition amongst the Specialist Pool participants by designating one of the participants to be the Primary Specialist. The Primary Specialist will be determined using objective evaluation of the relative quote performance of each Specialist and e-Specialist. The evaluation will be conducted on a quarterly basis and would include one or more of the following factors: time and size at the NBBO, average quote width, average quote size, and the relative share of electronic volume in a given class of options.[4] The Exchange will issue a Regulatory Bulletin at least five business days prior to each evaluation period with the evaluation criteria, including the relative weighting of each factor.

The Exchange believes that providing for a Primary Specialist to be designated based on competitive quote performance will encourage tighter and more liquid markets, and thus provide better markets for all investors. The Exchange notes that the Primary Specialist, like all Specialists on the Exchange today, would continue to be eligible to receive Directed Orders under Rule 964NY(b)(2)(B), but would continue to be subject to the restrictions in that provision, including the limitation on receiving no more than 40% of a Directed Order. Moreover, as is currently the case today, if the Primary Specialist were to receive a Directed Order under Rule 964NY(b)(2)(B), the Specialist Pool, including the Primary Specialist, would be ineligible to receive an allocation from that order and the NYSE Amex System would move to the next step in the allocation process—size pro rata allocation pursuant to Rule 964NY(b)(2)(D).

Under the proposed rule change, the Primary Specialist (instead of the Specialist) would receive any additional weighting in the size pro rata allocation amongst Specialist Pool participants. This additional weighting would be determined by the Exchange, as is currently the case now. Additionally, under the proposal, rather than a round robin allocation of non-Directed Orders for five contracts or fewer, all such orders would be allocated to the Primary Specialist after any allocation to Customers, not to exceed the size of their quote, provided the Primary Specialist is quoting at the NBBO.[5] If the Primary Specialist's quote size is less than the order of five contracts or fewer, any remaining contracts after the Primary Specialist receives its allocation will be allocated in accordance with Rule 964NY(b)(2)(D) (i.e., size pro rata).

In addition, as is the case under the current rule for the Specialist Pool, if the Primary Specialist is not quoting at the NBBO at the time the order for five or fewer contracts arrives, then the order will be executed in accordance with the provision of Rule 964NY(b)(2)(D).

Finally, the Exchange proposes to correct a typographical error in Rule 964.2NY(b)(3)(A) by changing the word ''on'' to ''one''.

NYSE Amex will not implement this rule change until such time that ATP Holders have been notified via Regulatory Bulletin.

Compliance Date

The Exchange plans to issue a notice announcing the compliance date of the rule change within 90 days from the effective date of the rule change.

2. Statutory Basis

The Exchange believes that this proposed rule change is consistent with Section 6(b) of the Securities Exchange Act of 1934 (''Act''),[6] in general, and furthers the objectives of Section 6(b)(5) of the Act [7] in particular, in that it is designed to prevent fraudulent and manipulative acts and practices, promote just and equitable principles of trade, 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. In particular, the proposed rule change seeks to enhance quote competition amongst Specialist Pool participants. Increasing quote competition should lead to narrower spreads and more liquid markets and thus benefit investors. Narrower spreads and more liquid markets should attract more order flow to the Exchange, enhancing price discovery and generally benefiting all participants on the Exchange. The Exchange further believes that the proposed rule change would be not be unfairly discriminatory in allocating orders of 5 contracts or fewer to the Primary Specialist because it uses objective standards to determine the Primary Specialist, and re-evaluates Specialist performance on a quarterly basis. In this respect, all Specialists compete on a quarterly basis to be designated the Primary Specialist based on objective standards that are published prior to each quarter in which Specialist performance is measured, and accordingly, all Specialists have the opportunity to be designated the Primary Specialist.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange does not believe that the proposed rule change will impose any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

No written comments were solicited or received with respect to the proposed rule change.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

Within 45 days of the date of publication of this notice in the **Federal Register** or within such longer period (i) as the Commission may designate up to 90 days of such date if it finds such longer period to be appropriate and publishes its reasons for so finding or (ii) as to which the self-regulatory organization consents, the Commission will:

(A) by order approve or disapprove the 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 email to *rule-comments@sec.gov.* Please include File Number SR–NYSEAmex–2012–31 on the subject line.

Paper Comments

• Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–1090.

[4] Notwithstanding the quarterly evaluation timeframe noted above, the first evaluation period may be longer or shorter than a calendar quarter, depending on the approval date of this filing. As noted above, the Exchange will announce the evaluation criteria and relative weighting of each factor at least 5 business days prior to that period and subsequent quarterly periods.

[5] The Exchange proposes to eliminate the round robin for such orders.

[6] 15 U.S.C. 78f(b).

[7] 15 U.S.C. 78f(b)(5).

All submissions should refer to File Number SR–NYSEAmex–2012–31. This file number should be included on the subject line if email is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet 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 Web site viewing and printing in the Commission's Public Reference Room, 100 F Street, NE., Washington, DC 20549, on official business days between the hours of 10 a.m. and 3 p.m. The text of the proposed rule change is available on the Commission's Web site at *http://www.sec.gov.* 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–NYSEAmex–2012–31 and should be submitted on or before June 21, 2012.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[8]

Kevin M. O'Neill,

Deputy Secretary.

[FR Doc. 2012–13148 Filed 5–30–12; 8:45 am]

BILLING CODE 8011–01–P

[8] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–67056; File No. SR–C2–2012–014]

Self-Regulatory Organizations; C2 Options Exchange, Incorporated; Notice of Filing and Immediate Effectiveness of a Proposed Rule Change Relating to the Name Change of the C2 Regulatory Oversight Committee

May 24, 2012.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (the "Act"),[1] and Rule 19b-4 thereunder,[2] notice is hereby given that on May 18, 2012, the C2 Options Exchange, Incorporated (the "Exchange" or "C2") 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 prepared by the Exchange. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The Exchange proposes to amend its Fourth Amended and Restated Bylaws (the "Bylaws") to change the name of the C2 Regulatory Oversight Committee. The text of the proposed rule change is available on the Exchange's Web site (*http://www.c2exchange.com/Legal/*), at the Exchange's Office of the Secretary, and at the Commission's Public Reference Room.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the Exchange included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in sections A, B, and C below, of the most significant aspects of such statements.

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

The Exchange proposes to amend the Bylaws to change the name of the Regulatory Oversight Committee. Currently, the Bylaws provide that the committees of the Board include, among others, a Regulatory Oversight Committee. Recently, the Board (pursuant to its authority under Section 4.5 of the Bylaws) delegated to the Regulatory Oversight Committee authority to oversee the adequacy and effectiveness of the Exchange's compliance functions, in addition to its regulatory oversight responsibilities. To more accurately reflect the current regulatory and compliance functions of the Regulatory Oversight Committee, the Exchange proposes to amend the Bylaws to replace all references to "Regulatory Oversight Committee" with "Regulatory Oversight and Compliance Committee." Additionally, the title of the Bylaws would be changed to the Fifth Amended and Restated Bylaws of C2.

2. Statutory Basis

The Exchange believes the proposed amendment is consistent with the Act and the rules and regulations thereunder applicable to the Exchange and, in particular, the requirements of Section 6(b) of the Act.[3] Specifically, the Exchange believes the proposed amendment is consistent with the Section 6(b)(5)[4] requirements that the rules of an exchange be designed to promote just and equitable principles of trade, to prevent fraudulent and manipulative acts, to remove impediments to and to perfect the mechanism for a free and open market and a national market system, and, in general, to protect investors and the public interest. The proposed amendment would protect investors and the public interest by clarifying the Bylaws to change the name of an Exchange committee to one that more accurately reflects the committee's current functions.

B. Self-Regulatory Organization's Statement on Burden on Competition

C2 does not believe that the proposed rule change will impose any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act.

[3] 15 U.S.C. 78f(b).

[4] 15 U.S.C. 78f(b)(5).

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received from Members, Participants, or Others

The Exchange neither solicited nor received comments on the proposed rule change.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The foregoing rule change has become effective pursuant to Section 19(b)(3)(A) [5] of the Act and paragraph (f) of Rule 19b–4 [6] thereunder. At any time within 60 days of the filing of the proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act.

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 email to *rule-comments@sec.gov*. Please include File Number SR–C2–2012–014 on the subject line.

Paper Comments

- Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–C2–2012–014. This file number should be included on the subject line if email is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet 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 Web site viewing and printing in the Commission's Public Reference Room, 100 F Street NE., Washington, DC 20549, on official business days between the hours of 10 a.m. and 3 p.m. Copies of the filing also will be available for inspection and copying at the principal office of the Exchange. 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–C2–2012–014 and should be submitted on or before June 21, 2012.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[7]

Kevin M. O'Neill,

Deputy Secretary.

[FR Doc. 2012–13147 Filed 5–30–12; 8:45 am]

BILLING CODE 8011–01–P

[5] 15 U.S.C. 78s(b)(3)(A).

[6] 17 CFR 240.19b–4(f).

[7] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–67055; File No. SR–CBOE–2012–050]

Self-Regulatory Organizations; Chicago Board Options Exchange, Incorporated; Notice of Filing and Immediate Effectiveness of a Proposed Rule Change Relating to the Name Change of the CBOE Regulatory Oversight Committee

May 24, 2012.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (the ''Act''),[1] and Rule 19b–4 thereunder,[2] notice is hereby given that on May 18, 2012, the Chicago Board Options Exchange, Incorporated (the ''Exchange'' or ''CBOE'') 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 prepared by the Exchange. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The Exchange proposes to amend its Fourth Amended and Restated Bylaws (the ''Bylaws'') to change the name of the CBOE Regulatory Oversight Committee. The text of the proposed rule change is available on the Exchange's Web site (*http://www.cboe.com/AboutCBOE/CBOELegalRegulatoryHome.aspx*), at the Exchange's Office of the Secretary, and at the Commission's Public Reference Room.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the Exchange included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in sections A, B, and C below, of the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

The Exchange proposes to amend the Bylaws to change the name of the Regulatory Oversight Committee. Currently, the Bylaws provide that the committees of the Board include, among others, a Regulatory Oversight Committee. Recently, the Board (pursuant to its authority under Section 4.5 of the Bylaws) delegated to the Regulatory Oversight Committee authority to oversee the adequacy and effectiveness of the Exchange's compliance functions, in addition to its regulatory oversight responsibilities. To more accurately reflect the current regulatory and compliance functions of the Regulatory Oversight Committee, the Exchange proposes to amend the Bylaws to replace all references to ''Regulatory Oversight Committee'' with ''Regulatory Oversight and Compliance Committee.'' Additionally, the title of the Bylaws would be changed to the Fifth Amended and Restated Bylaws of CBOE.

2. Statutory Basis

The Exchange believes the proposed amendment is consistent with the Act and the rules and regulations thereunder applicable to the Exchange

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

and, in particular, the requirements of Section 6(b) of the Act.[3] Specifically, the Exchange believes the proposed amendment is consistent with the Section 6(b)(5)[4] requirements that the rules of an exchange be designed to promote just and equitable principles of trade, to prevent fraudulent and manipulative acts, to remove impediments to and to perfect the mechanism for a free and open market and a national market system, and, in general, to protect investors and the public interest. The proposed amendment would protect investors and the public interest by clarifying the Bylaws to change the name of an Exchange committee to one that more accurately reflects the committee's current functions.

B. Self-Regulatory Organization's Statement on Burden on Competition

CBOE does not believe that the proposed rule change will impose any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

The Exchange neither solicited nor received comments on the proposed rule change.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The foregoing rule change has become effective pursuant to Section 19(b)(3)(A)[5] of the Act and paragraph (f) of Rule 19b–4[6] thereunder. At any time within 60 days of the filing of the proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act.

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:

[3] 15 U.S.C. 78f(b).

[4] 15 U.S.C. 78f(b)(5).

[5] 15 U.S.C. 78s(b)(3)(A).

[6] 17 CFR 240.19b–4(f).

Electronic Comments

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send an email to *rule-comments@sec.gov.* Please include File Number SR–CBOE–2012–050 on the subject line.

Paper Comments

- Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–CBOE–2012–050. This file number should be included on the subject line if email is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet 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 Web site viewing and printing in the Commission's Public Reference Room, 100 F Street NE., Washington, DC 20549, on official business days between the hours of 10 a.m. and 3 p.m. Copies of the filing also will be available for inspection and copying at the principal office of the Exchange. 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–CBOE–2012–050 and should be submitted on or before June 21, 2012.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[7]

Kevin M. O'Neill,

Deputy Secretary.

[FR Doc. 2012–13146 Filed 5–30–12; 8:45 am]

BILLING CODE 8011–01–P

[7] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–67054; File No. SR–NYSEArca–2012–25]

Self-Regulatory Organizations; NYSE Arca, Inc.; Order Granting Approval of Proposed Rule Change Relating to Listing and Trading of the WisdomTree Brazil Bond Fund Under NYSE Arca Equities Rule 8.600

May 24, 2012.

I. Introduction

On March 23, 2012, NYSE Arca, Inc. (''Exchange'' or ''NYSE Arca'') 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 shares (''Shares'') of the WisdomTree Brazil Bond Fund (''Fund'') under NYSE Arca Equities Rule 8.600. The proposed rule change was published for comment in the **Federal Register** on April 11, 2012.[3] The Commission received no comments on the proposal. This order grants approval of the proposed rule change.

II. Description of the Proposed Rule Change

The Exchange proposes to list and trade the Shares of the Fund pursuant to NYSE Arca Equities Rule 8.600, which governs the listing and trading of Managed Fund Shares on the Exchange. The Shares will be offered by WisdomTree Trust (''Trust''), a Delaware statutory trust registered with the Commission as an investment company.[4] The investment adviser to the Fund is WisdomTree Asset Management, Inc. (''Adviser''). The Fund's sub-adviser is Western Asset Management Company (''Sub-Adviser''). ALPS Distributors, Inc. serves as the distributor for the Trust. The Bank of New York Mellon is the administrator, custodian, and transfer agent for the Trust.

The Exchange represents that the Adviser is not affiliated with a broker-dealer. The Sub-Adviser is affiliated

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] *See* Securities Exchange Act Release No. 66753 (April 6, 2012), 77 FR 21827 (''Notice'').

[4] *See* Registration Statement on Form N–1A for the Trust under the Securities Act of 1933 (15 U.S.C. 77a) and under the Investment Company Act of 1940 (''1940 Act''), dated October 8, 2010 (File Nos. 333–132380 and 811–21864) (''Registration Statement''). In addition, the Commission has issued an order granting certain exemptive relief to the Trust under the 1940 Act. *See* Investment Company Act Release No. 28471 (October 27, 2008) (File No. 812–13458) (''Exemptive Order'').

with multiple broker-dealers and has implemented a ''fire wall'' with respect to such broker-dealers regarding access to information concerning the composition and/or changes to the Fund's portfolio. In addition, Sub-Adviser personnel who make decisions on the Fund's portfolio composition are subject to procedures designed to prevent the use and dissemination of material non-public information regarding the Fund's portfolio.[5]

Description of the Fund

The Fund will seek to provide investors with a high level of total return consisting of both income and capital appreciation. The Fund will be designed to provide exposure to a broad range of Brazilian government and corporate bonds through investment in both local currency (*i.e.,* Brazilian real) and U.S. dollar-denominated Fixed Income Securities, which will include bonds, notes, or other debt obligations, including loan participation notes (''LPNs''),[6] inflation-linked debt, and debt securities issued by ''supranational issuers,'' such as the European Investment Bank, International Bank for Reconstruction and Development, and the International Finance Corporation, as well as development agencies supported by other national governments. The Fund may invest to a lesser extent in Money Market Securities and derivative instruments, as described below.

The Fund will be designed to provide broad exposure to Brazilian government and corporate bonds and will invest in a range of instruments with varying credit risk and duration. The Fund intends to invest in bonds and debt instruments issued by the government of Brazil and its agencies and instrumentalities and bonds and other debt instruments issued by corporations organized in Brazil.[7] The Fund also may invest in bonds and debt instruments denominated in Brazilian real and issued by supranational issuers, as described above. The Fund intends to invest at least 70% of its net assets in Fixed Income Securities. The Fund will invest only in corporate bonds that the Adviser or Sub-Adviser deems to be sufficiently liquid. Generally a corporate bond must have $200 million or more par amount outstanding and significant par value traded to be considered as an eligible investment. Economic and other conditions in Brazil may, from time to time, lead to a decrease in the average par amount outstanding of bond issuances. Therefore, although the Fund does not intend to do so, the Fund may invest up to 20% of its net assets in corporate bonds with less than $200 million par amount outstanding, including up to 5% of its assets in corporate bonds with less than $100 million par amount outstanding, if (i) the Adviser or Sub-Adviser deems such security to be sufficiently liquid based on its analysis of the market for such security (based on, for example, broker-dealer quotations or its analysis of the trading history of the security or the trading history of other securities issued by the issuer), (ii) such investment is consistent with the Fund's goal of providing exposure to a broad range of Brazilian government and corporate bonds, and (iii) such investment is deemed by the Adviser or Sub-Adviser to be in the best interest of the Fund.

The Fund typically will maintain aggregate portfolio duration of between two and ten years. Aggregate portfolio duration is a measure of the portfolio's sensitivity to changes in the level of interest rates. The Fund's actual portfolio duration may be longer or shorter depending upon market conditions.

The universe of Brazilian Fixed Income Securities currently includes securities that are rated ''investment grade'' as well as ''non-investment grade'' securities. The Fund is designed to provide a broad-based, representative exposure to Brazilian government and corporate bonds and therefore will invest in both investment grade and non-investment grade securities in a manner designed to provide this exposure. The Fund currently expects that it will have 65% or more of its assets invested in investment grade securities, and no more than 35% of its assets invested in non-investment grade securities. Because the Fund is designed to provide exposure to a broad range of Brazilian government and corporate bonds, and because the debt ratings of the Brazilian government and those corporate issuers will change from time to time, the exact percentage of the Fund's investments in investment grade and non-investment grade securities will change from time to time in response to economic events and changes to the credit ratings of the Brazilian government and corporate issuers.[8] Within the non-investment grade category, some issuers and instruments are considered to be of lower credit quality and at higher risk of default. In order to limit its exposure to these more speculative credits, the Fund will not invest more than 15% of its assets in securities rated B or below by Moody's, or equivalently rated by S&P or Fitch. The Fund does not intend to invest in unrated securities. However, it may do so to a limited extent, such as where a rated security becomes unrated, if such security is determined by the Adviser and Sub-Adviser to be of comparable quality. In determining whether a security is of ''comparable quality,'' the Adviser and Sub-Adviser will consider, for example, whether the issuer of the security has issued other rated securities.

The Fund will hold Fixed Income Securities of at least 13 non-affiliated issuers. The Fund will not concentrate 25% or more of the value of its total assets (taken at market value at the time of each investment) in any one industry, as that term is used in the 1940 Act (except that this restriction does not apply to obligations issued by the U.S. government or its agencies and instrumentalities or government-sponsored enterprises).

The Fund intends to qualify each year as a regulated investment company (''RIC'') under Subchapter M of the Internal Revenue Code of 1986, as amended. The Fund will invest its assets, and otherwise conduct its operations, in a manner that is intended to satisfy the qualifying income, diversification, and distribution requirements necessary to establish and maintain RIC qualification under Subchapter M. The Subchapter M diversification tests generally require that (i) the Fund invest no more than 25% of its total assets in securities (other than securities of the U.S.

[5] *See* Commentary .06 to NYSE Arca Equities Rule 8.600. The Exchange represents that, in the event (a) the Adviser or the Sub-Adviser becomes newly affiliated with a broker-dealer, or (b) any new adviser or sub-adviser becomes affiliated with a broker-dealer, it will implement a fire wall with respect to such broker-dealer regarding access to information concerning the composition and/or changes to the portfolio, and will be subject to procedures designed to prevent the use and dissemination of material non-public information regarding such portfolio.

[6] The Fund may invest in LPNs with a minimum outstanding principal amount of $200 million that the Adviser or Sub-Adviser deems to be liquid. The Adviser represents that the Fund will invest a limited percentage of its assets in LPNs.

[7] The category of ''Brazilian debt'' includes both U.S. dollar-denominated debt and non-U.S. or ''local'' currency debt. The market for Brazilian local currency debt is larger and more actively traded than the market for Brazilian U.S. dollar-denominated debt. The Adviser represents that Brazilian sovereign debt is issued in large par size and tends to be very liquid. Real-denominated Brazilian debt issued by supranational entities is also actively traded. Intra-day, executable price quotations on such instruments are available from major broker-dealer firms. Intra-day price information is available through subscription services, such as Bloomberg and Thomson Reuters, which can be accessed by authorized participants and other investors.

[8] As of January 31, 2012, Brazilian government debt was rated investment grade by S&P, Moody's, and Fitch. *See http://brasilstocks.com/bonds.*

government or other RICs) of any one issuer or two or more issuers that are controlled by the Fund and that are engaged in the same, similar, or related trades or businesses, and (ii) at least 50% of the Fund's total assets consist of cash and cash items, U.S. government securities, securities of other RICs, and other securities, with investments in such other securities limited in respect of any one issuer to an amount not greater than 5% of the value of the Fund's total assets and 10% of the outstanding voting securities of such issuer.

In addition to satisfying the above referenced RIC diversification requirements, no portfolio security held by the Fund (other than U.S. government securities) will represent more than 30% of the weight of the portfolio, and the five highest weighted portfolio securities of the Fund (other than U.S. government securities) will not in the aggregate account for more than 65% of the weight of the portfolio. For these purposes, the Fund may treat repurchase agreements collateralized by U.S. government securities as U.S. government securities.

Money Market Securities

The Fund intends to invest in Money Market Securities (as described below) in a manner consistent with its investment objective in order to help manage cash flows in and out of the Fund, such as in connection with payment of dividends or expenses and to satisfy margin requirements, to provide collateral, or to otherwise back investments in derivative instruments. For these purposes, Money Market Securities include: Short-term, high-quality obligations issued or guaranteed by the U.S. Treasury or the agencies or instrumentalities of the U.S. government; short-term, high-quality securities issued or guaranteed by non-U.S. governments, agencies, and instrumentalities; repurchase agreements backed by U.S. government securities; money market mutual funds; and deposits and other obligations of U.S. and non-U.S. banks and financial institutions. All Money Market Securities acquired by the Fund will be rated investment grade. The Fund does not intend to invest in any unrated money market securities. However, it may do so, to a limited extent, such as where a rated Money Market Security becomes unrated, if such Money Market Security is determined by the Adviser or the Sub-Adviser to be of comparable quality.

Derivative Instruments

Consistent with the Exemptive Order, the Fund may use derivative instruments as part of its investment strategies. Examples of derivative instruments include listed futures contracts,[9] forward currency contracts, non-deliverable forward currency contracts,[10] currency swaps (*e.g.,* Brazilian real vs. U.S. dollar), interest rate swaps,[11] total return swaps,[12] currency options, options on futures contracts, and credit-linked notes.[13] The Fund's use of derivative instruments (other than credit-linked notes) will be collateralized or otherwise backed by investments in short term, high-quality U.S. money market securities and other liquid fixed income securities. The Fund expects that no more than 30% of the value of the Fund's net assets will be invested in derivative instruments. Such investments will be consistent with the Fund's investment objective and will not be used to enhance leverage.

With respect to certain kinds of derivative transactions entered into by the Fund that involve obligations to make future payments to third parties, including, but not limited to, futures, forward contracts, swap contracts, the purchase of securities on a when-issued or delayed delivery basis, or reverse repurchase agreements, under applicable federal securities laws, rules, and interpretations thereof, the Fund must ''set aside'' liquid assets or engage in other measures to ''cover'' open positions with respect to such transactions.

The Fund may engage in foreign currency transactions and may invest directly in foreign currencies in the form of bank and financial institution deposits, certificates of deposit, and bankers acceptances denominated in a specified non-U.S. currency. The Fund may enter into forward currency contracts in order to ''lock in'' the exchange rate between the currency it will deliver and the currency it will receive for the duration of the contract.[14]

The Fund may enter into repurchase agreements with counterparties that are deemed to present acceptable credit risks, and may enter into reverse repurchase agreements, which involve the sale of securities held by the Fund subject to its agreement to repurchase the securities at an agreed upon date or upon demand and at a price reflecting a market rate of interest.

The Fund may invest in the securities of other investment companies (including money market funds and exchange-traded funds). The Fund may hold up to an aggregate amount of 15% of its net assets in (1) illiquid securities, (2) Rule 144A securities, and (3) loan interests (such as loan participations and assignments, but not including LPNs). Illiquid securities include securities subject to contractual or other restrictions on resale and other instruments that lack readily available markets. The Fund will not invest in non-U.S. equity securities.

Additional information regarding the Shares and the Fund, including investment strategies, Fixed Income Securities, risks, creation and redemption procedures, fees, portfolio holdings disclosure policies, distributions, and taxes can be found in the Notice and Registration Statement, as applicable.[15]

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[9] The listed futures contracts in which the Fund may invest will be listed on exchanges either in the U.S. or in Brazil. Brazil's primary financial markets regulator, the Comissao de Valores Mobiliarios, is a signatory to the International Organization of Securities Commissions (''IOSCO'') Multilateral Memorandum of Understanding (''MMOU''), which is a multi-party information sharing arrangement among major financial regulators. Both the Commission and the Commodity Futures Trading Commission are signatories to the IOSCO MMOU.

[10] A forward currency contract is an agreement to buy or sell a specific currency on a future date at a price set at the time of the contract.

[11] An interest rate swap involves the exchange of a floating interest rate payment for a fixed interest rate payment.

[12] A total return swap is an agreement between two parties in which one party agrees to make payments of the total return of a reference asset in return for payments equal to a rate of interest on another reference asset.

[13] The Fund may invest in credit-linked notes. A credit linked note is a type of structured note whose value is linked to an underlying reference asset. Credit linked notes typically provide periodic payments of interest as well as payment of principal upon maturity. The value of the periodic payments and the principal amount payable upon maturity are tied (positively or negatively) to a reference asset such as an index, government bond, interest rate, or currency exchange rate. The ongoing payments and principal upon maturity typically will increase or decrease depending on increases or decreases in the value of the reference asset. The Fund's investments in credit-linked notes will be limited to notes providing exposure to Brazilian Fixed Income Securities. The Fund's overall investment in credit-linked notes will not exceed 25% of the Fund's assets.

[14] The Fund will invest only in currencies, and instruments that provide exposure to such currencies, that have significant foreign exchange turnover and are included in the Bank for International Settlements, *Triennial Central Bank Survey,* Report on Global Foreign Exchange Market Activity in 2010 December 2010 (''BIS Survey''). The Fund may invest in currencies, and instruments that provide exposure to such currencies, selected from the top 40 currencies (as measured by percentage share of average daily turnover for the applicable month and year) included in the BIS Survey.

[15] *See supra* notes 3 and 4, respectively.

III. Discussion and Commission's Findings

The Commission has carefully reviewed the proposed rule change and finds that it is consistent with the requirements of Section 6 of the Act [16] and the rules and regulations thereunder applicable to a national securities exchange.[17] In particular, the Commission finds that the proposal is consistent with Section 6(b)(5) of the Act,[18] which requires, among other things, that the Exchange's rules be 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 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. The Commission notes that the Fund and the Shares must comply with the requirements of NYSE Arca Equities Rule 8.600 to be listed and traded on the Exchange.

The Commission finds that the proposal to list and trade the Shares on the Exchange is consistent with Section 11A(a)(1)(C)(iii) of the Act,[19] 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. Quotation and last-sale information for the Shares will be available via the Consolidated Tape Association (''CTA'') high-speed line. In addition, the Portfolio Indicative Value (''PIV''), as defined in NYSE Arca Equities Rule 8.600(c)(3), will be widely disseminated by one or more major market data vendors at least every 15 seconds during the Exchange's Core Trading Session.[20] On each business day, before commencement of trading in Shares in the Core Trading Session on the Exchange, the Fund will disclose on its Web site the Disclosed Portfolio, as defined in NYSE Arca Equities Rule 8.600(c)(2), that will form the basis for the Fund's calculation of the NAV at the end of the business day.[21] The NAV of the Fund's Shares generally will be calculated once daily Monday through Friday as of the close of regular trading on the New York Stock Exchange (''NYSE'') (generally 4:00 p.m., Eastern time or ''E.T.''). In addition, information regarding market price and trading volume of the Shares will be continually available on a real-time basis throughout the day on brokers' computer screens and other electronic services, and the previous day's closing price and trading volume information for the Shares will be published daily in the financial section of newspapers. The Web site for the Fund will include a form of the prospectus for the Fund that may be downloaded, additional data relating to NAV, and other applicable quantitative information, updated on a daily basis. Intra-day and end-of-day prices are readily available through major market data providers and broker-dealers for the Fixed Income Securities, Money Market Securities, and derivative instruments held by the Fund.

The Commission further believes that the proposal to list and trade the Shares is reasonably designed to promote fair disclosure of information that may be necessary to price the Shares appropriately and to prevent trading when a reasonable degree of transparency cannot be assured. The Commission notes that the Exchange will obtain a representation from the issuer of the Shares that the NAV and the Disclosed Portfolio will be made available to all market participants at the same time.[22] In addition, the Exchange will halt trading in the Shares under the specific circumstances set forth in NYSE Arca Equities Rule 8.600(d)(2)(D), and may halt trading in the Shares if trading is not occurring in the securities and/or the financial instruments comprising the Disclosed Portfolio of the Fund, or if other unusual conditions or circumstances detrimental to the maintenance of a fair and orderly market are present.[23] The Exchange will consider the suspension of trading in or removal from listing of the Shares if the PIV is no longer calculated or available or the Disclosed Portfolio is not made available to all market participants at the same time.[24] While the Adviser is not affiliated with a broker-dealer, the Sub-Adviser is affiliated with multiple broker-dealers and has implemented a ''fire wall'' with respect to such broker-dealers regarding access to information concerning the composition and/or changes to the Fund's portfolio.[25] Further, the Commission notes that the Reporting Authority that provides the Disclosed Portfolio must implement and maintain, or be subject to, procedures designed to prevent the use and dissemination of material non-public information regarding the actual components of the portfolio.[26] The Exchange states that it has a general policy prohibiting the distribution of material, non-public information by its employees. The Commission also notes that the Fund will not invest in non-U.S. equity securities, and the Exchange may obtain information via the Intermarket Surveillance Group (''ISG'') from other exchanges that are members of ISG or with which the Exchange has in place a comprehensive surveillance sharing agreement.[27]

The Exchange further represents that the Shares are deemed to be equity securities, thus rendering trading in the Shares subject to the Exchange's

[16] 15 U.S.C. 78f.

[17] In approving this proposed rule change, the Commission has considered the proposed rule's impact on efficiency, competition, and capital formation. *See* 15 U.S.C. 78c(f).

[18] 15 U.S.C. 78f(b)(5).

[19] 15 U.S.C. 78k–1(a)(1)(C)(iii).

[20] According to the Exchange, several major market data vendors display and/or make widely available PIVs published on the CTA or other data feeds. In addition, during hours when the markets for Fixed Income Securities in the Fund's portfolio are closed, the PIV will be updated at least every 15 seconds during the Core Trading Session to reflect currency exchange fluctuations.

[21] The Disclosed Portfolio will include, as applicable, the names, quantity, percentage weighting, and market value of Fixed Income Securities and other assets held by the Fund and the characteristics of such assets. The Web site and information will be publicly available at no charge.

[22] *See* NYSE Arca Equities Rule 8.600(d)(1)(B) (requiring, in addition, that the Exchange obtain a representation from the issuer of the Shares that the NAV will be calculated daily).

[23] With respect to trading halts, the Exchange may consider all relevant factors in exercising its discretion to halt or suspend trading in the Shares of the Fund. Trading in Shares of the Fund will be halted if the circuit breaker parameters in NYSE Arca Equities Rule 7.12 have been reached. Trading also may be halted because of market conditions or for reasons that, in the view of the Exchange, make trading in the Shares inadvisable.

[24] *See* NYSE Arca Equities Rule 8.600(d)(2)(C)(ii).

[25] *See supra* note 5 and accompanying text. The Commission notes that an investment adviser to an open-end fund is required to be registered under the Investment Advisers Act of 1940 (''Advisers Act''). As a result, the Adviser and Sub-Adviser and their related personnel are subject to the provisions of Rule 204A–1 under the Advisers Act relating to codes of ethics. This Rule requires investment advisers to adopt a code of ethics that reflects the fiduciary nature of the relationship to clients as well as compliance with other applicable securities laws. Accordingly, procedures designed to prevent the communication and misuse of non-public information by an investment adviser must be consistent with Rule 204A–1 under the Advisers Act. In addition, Rule 206(4)–7 under the Advisers Act makes it unlawful for an investment adviser to provide investment advice to clients unless such investment adviser has (i) adopted and implemented written policies and procedures reasonably designed to prevent violation, by the investment adviser and its supervised persons, of the Advisers Act and the Commission rules adopted thereunder; (ii) implemented, at a minimum, an annual review regarding the adequacy of the policies and procedures established pursuant to subparagraph (i) above and the effectiveness of their implementation; and (iii) designated an individual (who is a supervised person) responsible for administering the policies and procedures adopted under subparagraph (i) above.

[26] *See* NYSE Arca Equities Rule 8.600(d)(2)(B)(ii).

[27] *See* Notice, *supra* note 3.

existing rules governing the trading of equity securities. In support of this proposal, the Exchange has made representations, including:

(1) The Shares will be subject to NYSE Arca Equities Rule 8.600, which sets forth the initial and continued listing criteria applicable to Managed Fund Shares.

(2) The Exchange has appropriate rules to facilitate transactions in the Shares during all trading sessions.

(3) The Exchange's surveillance procedures applicable to derivative products, which include Managed Fund Shares, are adequate to properly monitor Exchange trading of the Shares in all trading sessions and to deter and detect violations of Exchange rules and applicable federal securities laws.

(4) Prior to the commencement of trading, the Exchange will inform its Equity Trading Permit Holders in an Information Bulletin of the special characteristics and risks associated with trading the Shares. Specifically, the Information Bulletin will discuss the following: (a) The procedures for purchases and redemptions of Shares in Creation Unit aggregations (and that Shares are not individually redeemable); (b) NYSE Arca Equities Rule 9.2(a), which imposes a duty of due diligence on its Equity Trading Permit Holders to learn the essential facts relating to every customer prior to trading the Shares; (c) the risks involved in trading the Shares during the Opening and Late Trading Sessions when an updated PIV will not be calculated or publicly disseminated; (d) how information regarding the PIV is disseminated; (e) the requirement that Equity Trading Permit Holders deliver a prospectus to investors purchasing newly issued Shares prior to or concurrently with the confirmation of a transaction; and (f) trading information.

(5) For initial and/or continued listing, the Fund must be in compliance with Rule 10A–3 under the Act,[28] as provided by NYSE Arca Equities Rule 5.3.

(6) The Fund may hold up to an aggregate amount of 15% of its net assets in: (a) Illiquid securities; (b) Rule 144A securities; and (c) loan interests (such as loan participations and assignments, but not including LPNs).

(7) The Fund expects that no more than 30% of the value of the Fund's net assets will be invested in derivative instruments, and such investments will be consistent with the Fund's investment objective and will not be used to enhance leverage.

(8) The Fund will not invest in non-U.S. equity securities.

(9) A minimum of 100,000 Shares of the Fund will be outstanding at the commencement of trading on the Exchange.

This approval order is based on all of the Exchange's representations.

For the foregoing reasons, the Commission finds that the proposed rule change is consistent with Section 6(b)(5) of the Act [29] and the rules and regulations thereunder applicable to a national securities exchange.

IV. Conclusion

It is therefore ordered, pursuant to Section 19(b)(2) of the Act,[30] that the proposed rule change (SR–NYSEArca–2012–25) be, and it hereby is, approved.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[31]

Kevin M. O'Neill,

Deputy Secretary.

[FR Doc. 2012–13145 Filed 5–30–12; 8:45 am]

BILLING CODE 8011–01–P

[28] *See* 17 CFR 240.10A–3.

[29] 15 U.S.C. 78f(b)(5).

[30] 15 U.S.C. 78s(b)(2).

[31] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–67047; File No. SR–Phlx–2012–70]

Self-Regulatory Organizations; NASDAQ OMX PHLX LLC; Notice of Filing and Immediate Effectiveness of Proposed Rule Change Relating to Reversal and Conversion Strategies

May 23, 2012.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 ("Act"),[1] and Rule 19b–4 [2] thereunder, notice is hereby given that, on May 16, 2012, NASDAQ OMX PHLX LLC ("Phlx" or "Exchange") filed with the Securities and Exchange Commission ("SEC" or "Commission") the proposed rule change as described in Items I, II and III below, which Items have been prepared by the Exchange. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The Exchange proposes to amend a fee cap on equity options transactions on certain reversals [3] and conversion [4] strategies in Section II, entitled "Equity Options Fees." [5] The Exchange also proposes to make technical amendments to the Pricing Schedule.

The text of the proposed rule change is available on the Exchange's Web site at *http://www.nasdaqtrader.com/micro.aspx?id=PHLXfilings,* at the principal office of the Exchange, and at the Commission's Public Reference Room.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the Exchange included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in sections A, B, and C below, of the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

The purpose of the proposed rule change is to amend the applicability of a fee cap relating to reversal and conversion strategies in Section II of the Pricing Schedule to conform the applicability of that cap to that of the dividend,[6] merger [7] and short stock interest [8] strategies cap. The Exchange believes that all strategy caps should be applied in the same manner, in this case

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] Reversals are established by combining a short stock position with a short put and a long call position that shares the same strike and expiration.

[4] Conversions are established by combining a long position in the underlying security with a long put and a short call position that shares the same strike and expiration.

[5] Section II Equity Options Fees include options overlying equities, ETFs, ETNs, indexes and HOLDRS which are Multiply Listed.

[6] A dividend strategy is defined as transactions done to achieve a dividend arbitrage involving the purchase, sale and exercise of in-the-money options of the same class, executed the first business day prior to the date on which the underlying stock goes ex-dividend.

[7] A merger strategy is defined as transactions done to achieve a merger arbitrage involving the purchase, sale and exercise of options of the same class and expiration date, executed the first business day prior to the date on which shareholders of record are required to elect their respective form of consideration, i.e., cash or stock.

[8] A short stock interest strategy is defined as transactions done to achieve a short stock interest arbitrage involving the purchase, sale and exercise of in-the-money options of the same class.

only when such members are trading in their own proprietary accounts.

Currently, Market Maker,[9] Professional,[10] Firm and Broker-Dealer equity option transaction fees are capped at $1,000 for dividend, merger and short stock interest strategies executed on the same trading day in the same options class when such members are trading in their own proprietary accounts.[11] The Exchange also currently has a cap for reversal and conversion strategies wherein Market Maker, Professional, Firm and Broker-Dealer options transaction fees in Multiply Listed Options are capped at $500 per day for reversal and conversion strategies executed on the same trading day in the same options class (''Reversal and Conversion Cap'').[12] The Exchange proposes to further qualify the Reversal and Conversion Cap by applying the cap only when such members are trading in their own proprietary accounts, similar to dividend, merger and short stock interest strategies.

Additionally, the Exchange proposes to make certain technical amendments to the Pricing Schedule. The Exchange recently amended the title of the Pricing Schedule from a ''Fee Schedule'' to a ''Pricing Schedule.''[13] There are a few places in the Pricing Schedule, namely in Section III, Part A (Other Transaction Fees, PIXL Pricing) and Section VII ((NASDAQ OMX PSX Fees, Other Requests for Data) that still refer to a Fee Schedule. The Exchange is proposing to amend those references from ''Fee Schedule'' to a ''Pricing Schedule.'' The Exchange is also proposing to remove a reference in Section I (Rebates and Fees for Adding and Removing Liquidity in Select Symbols) to the Market Exhaust auction. The Exchange recently filed a rule change to discontinue the Market Exhaust functionality, a feature of the Exchange's PHLX XL® automated trading system.[14] The reference to Market Exhaust was deleted from Rule 1080(c). This functionality was discontinued as of January 31, 2012. The Exchange proposes to remove a reference to Market Exhaust in Section I of the Pricing Schedule. Finally, the Exchange purposes to replace certain reference symbols with numbers for clarity in various sections of the Pricing Schedule.[15]

2. Statutory Basis

The Exchange believes that its proposal to amend its Pricing Schedule is consistent with Section 6(b) of the Act[16] in general, and furthers the objectives of Section 6(b)(4) of the Act[17] in particular, in that it is an equitable allocation of reasonable fees and other charges among Exchange members and other persons using its facilities.

The Exchange believes that the proposed amendment to the applicability of the Reversal and Conversion Cap is reasonable because the Exchange is proposing to apply the cap only when such members are trading in their own proprietary account, which is the case today for dividend, merger and short stock interest strategies. All members would continue to be offered an opportunity to reduce option transaction fees in Multiply Listed options for reversals and conversions.[18] The Exchange also believes that the proposed amendment to the applicability of the Reversal and Conversion Cap is equitable and not unfairly discriminatory because the Exchange would uniformly apply the reversal cap to all members.

The Exchange believes that the technical amendments are reasonable, equitable and not unfairly discriminatory because the Exchange intends to amend the Pricing Schedule to conform the text to recent rule amendments which eliminated and/or replaced certain references.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange does not believe that the proposed rule change will impose any burden on competition not necessary or appropriate in furtherance of the purposes of the Act.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

No written comments were either solicited or received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The foregoing rule change has become effective pursuant to Section 19(b)(3)(A)(ii) of the Act.[19] At any time within 60 days of the filing of the proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act. If the Commission takes such action, the Commission shall institute proceedings to determine whether the proposed rule should be approved or disapproved.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send an email to *rule-comments@sec.gov*. Please include File Number SR–Phlx–2012–70 on the subject line.

Paper Comments

- Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–Phlx–2012–70. This file number should be included on the subject line if email is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's

[9] The Exchange market maker category includes Specialists (*see* Rule 1020) and Registered Options Traders (*see* Rule 1014(b)(i) and (ii), which includes Streaming Quote Traders (''SQTs'') (*see* Rule 1014(b)(ii)(A)) and Remote Streaming Quote Traders (''RSQTs'') (*see* Rule 1014(b)(ii)(B)). This would also include Directed Participants. The term ''Directed Participant'' applies to transactions for the account of a Specialist, SQT or RSQT resulting from a Customer order that is (1) directed to it by an order flow provider, and (2) executed by it electronically on Phlx XL II.

[10] The Exchange defines a ''professional'' as any person or entity that (i) is not a broker or dealer in securities, and (ii) places more than 390 orders in listed options per day on average during a calendar month for its own beneficial account(s) (hereinafter ''Professional'').

[11] Equity option transaction fees for dividend, merger and short stock interest strategies combined will be further capped at the greater of $10,000 per member or $25,000 per member organization.

[12] The Reversal and Conversion Cap applies to executions occurring on either of the two days preceding the standard options expiration date, which is typically the third Thursday and Friday of every month.

[13] *See* Securities Exchange Act Release No. 66668 (March 28, 2012), 77 FR 20090 (April 3, 2012) (SR–PhlX–2012–35).

[14] *See* Securities Exchange Act Release No. 66087 (January 3, 2012), 77 FR 1095 (January 9, 2012) (SR–Phlx–2011–182).

[15] For example, various symbols such as ''∞,'' ''+'' and other symbols that are non-numeric, while be replaced with numbers.

[16] 15 U.S.C. 78f(b).

[17] 15 U.S.C. 78f(b)(4).

[18] Customers are not subject to the Reversal and Conversion Cap because they do not pay option transaction charges for reversal and conversion strategies.

[19] 15 U.S.C. 78s(b)(3)(A)(ii).

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 Web site viewing and printing in the Commission's Public Reference Room, 100 F Street NE., Washington, DC 20549, on official business days between the hours of 10 a.m. and 3 p.m. Copies of the filing also will be available for inspection and copying at the principal office of the Exchange. 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–Phlx–2012–70 and should be submitted on or before June 21, 2012.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[20]

Elizabeth M. Murphy,

Secretary.

[FR Doc. 2012–13144 Filed 5–30–12; 8:45 am]

BILLING CODE 8011–01–P

SMALL BUSINESS ADMINISTRATION

Revocation of License of Small Business Investment Company

Pursuant to the authority granted to the United States Small Business Administration by the Wind-Up Order of the United States District Court for the Southern District of New York, dated June 8, 2011, the United States Small Business Administration hereby revokes the license of LV Equity Partners SBIC, L.P. a Delaware limited partnership, to function as a small business investment company under the Small Business Investment Company License No. 02720594 issued to LV Equity Partners SBIC, on August 25, 1999 and said license is hereby declared null and void as of June 8, 2011.

United States Small Business Administration.

[20] 17 CFR 200.30–3(a)(12).

Dated: May 15, 2012.

Sean J. Greene,

Associate Administrator for Investment.

[FR Doc. 2012–13131 Filed 5–30–12; 8:45 am]

BILLING CODE 8025–01–P

SMALL BUSINESS ADMINISTRATION

Revocation of License of Small Business Investment Company

Pursuant to the authority granted to the United States Small Business Administration by the Wind-Up Order of the United States District Court for the District of Columbia, dated September 27, 2011, the United States Small Business Administration hereby revokes the license of Women's Growth Capital Fund I, LLLP, a Delaware limited partnership, to function as a small business investment company under the Small Business Investment Company License No. 03730213 issued to Women's Growth Capital Fund I, LLLP, on June 17, 1998 and said license is hereby declared null and void as of September 27, 2011.

United States Small Business Administration.

Dated: May 15, 2012.

Sean J. Greene,

Associate Administrator for Investment.

[FR Doc. 2012–13134 Filed 5–30–12; 8:45 am]

BILLING CODE 8025–01–P

SMALL BUSINESS ADMINISTRATION

Revocation of License of Small Business Investment Company

Pursuant to the authority granted to the United States Small Business Administration under the Small Business Investment Act of 1958, under Section 309 of the Act and Section 107.1900 of the Small Business Administration Rules And Regulations (13 CFR 107.1900) to function as a small business investment company under the Small Business Investment Company License No. 09/79–0399 issued to Walden-SBIC, LP, said license is hereby declared null and void.

United States Small Business Administration.

Dated: May 15, 2012.

Sean J. Greene,

Associate Administrator for Investment.

[FR Doc. 2012–13133 Filed 5–30–12; 8:45 am]

BILLING CODE 8025–01–P

SMALL BUSINESS ADMINISTRATION

Surrender of License of Small Business Investment Company

Pursuant to the authority granted to the United States Small Business Administration by the Wind-Up Order of the United States District Court of the Middle District Court of Tennessee, Nashville Division, dated September 6, 2011 the United States Small Business Administration hereby surrender the license of Capital Across America, L.P. a Delaware limited partnership, to function as a small business investment company under the Small Business Investment Company License No. 04040273 issued to Capital Across America, on June 17, 1998 and said license is hereby declared null and void as of December 5, 2011.

United States Small Business Administration.

Dated: May 15, 2012.

Sean J. Greene,

Associate Administrator for Investment.

[FR Doc. 2012–13132 Filed 5–30–12; 8:45 am]

BILLING CODE 8025–01–P

DEPARTMENT OF STATE

[Public Notice 7903]

Notice of Renewal of Advisory Committee on International Law Charter

Summary: The Department of State has renewed the Charter of the Advisory Committee on International Law. Through this Committee, the Department of State will continue to obtain the views and advice of a cross section of the country's outstanding members of the legal profession on significant issues of international law. The Committee's consideration of these legal issues in the conduct of our foreign affairs provides a unique contribution to the creation and promotion of U.S. foreign policy. The Under Secretary for Management has determined the Committee is necessary and in the public interest.

The Committee is comprised of all former Legal Advisers of the Department of State and up to 25 individuals appointed by the current Legal Adviser. The Committee follows the procedures prescribed by the Federal Advisory Committee Act (FACA). Meetings will be open to the public unless a determination is made in accordance with section 1 O(d) of the FACA and 5 U.S.C. 552b(c) that a meeting or portion of the meeting should be closed to the public. Notice of each meeting will be published in the **Federal Register** at least 15 days prior to the meeting, unless there are extraordinary circumstances that require shorter notice.

For further information, please contact Theodore P. Kill, Executive Director, Advisory Committee on International Law, Department of State, at 202–776–8344 or *killtp@state.gov.*

Dated: May 23, 2012.

Theodore P. Kill,

Attorney Advisor, Office of Claims and Investment, Office of the Legal Advisor, Executive Director, Advisory Committee on International Law.

[FR Doc. 2012–13226 Filed 5–30–12; 8:45 am]

BILLING CODE 4710–08–P

DEPARTMENT OF STATE

[Public Notice 7906]

Culturally Significant Object Imported for Exhibition Determinations: ''Elegance and Refinement: The Still-Life Paintings of Willem van Aelst''

AGENCY: Department of State.

ACTION: Notice, correction.

SUMMARY: On February 22, 2012, notice was published on page 10599 of the **Federal Register** (volume 77, number 35) of determinations made by the Department of State pertaining to the exhibition ''Elegance and Refinement: The Still-Life Paintings of Willem van Aelst.'' The referenced notice is corrected here to include one additional object as part of the exhibition. Notice is hereby given of the following determinations: Pursuant to the authority vested in me by the Act of October 19, 1965 (79 Stat. 985; 22 U.S.C. 2459), Executive Order 12047 of March 27, 1978, the Foreign Affairs Reform and Restructuring Act of 1998 (112 Stat. 2681, *et seq.;* 22 U.S.C. 6501 note, *et seq.*), Delegation of Authority No. 234 of October 1, 1999, and Delegation of Authority No. 236–3 of August 28, 2000 (and, as appropriate, Delegation of Authority No. 257 of April 15, 2003), I hereby determine that the additional object to be included in the exhibition ''Elegance and Refinement: The Still-Life Paintings of Willem van Aelst,'' imported from abroad for temporary exhibition within the United States, is of cultural significance. The additional object is imported pursuant to a loan agreement with the foreign owner or custodian. I also determine that the exhibition or display of the exhibit object at the National Gallery of Art, Washington, DC, from on or about June 24, 2012, until on or about October 14, 2012, and at possible additional exhibitions or venues yet to be determined, is in the national interest. I have ordered that Public Notice of these Determinations be published in the **Federal Register**.

FOR FURTHER INFORMATION CONTACT: For further information, including a description of the additional object, contact Paul W. Manning, Attorney-Adviser, Office of the Legal Adviser, U.S. Department of State (telephone: 202–632–6469). The mailing address is U.S. Department of State, SA–5, L/PD, Fifth Floor (Suite 5H03), Washington, DC 20522–0505.

Dated: May 23, 2012.

J. Adam Ereli,

Principal Deputy Assistant Secretary, Bureau of Educational and Cultural Affairs, Department of State.

[FR Doc. 2012–13217 Filed 5–30–12; 8:45 am]

BILLING CODE 4710–05–P

DEPARTMENT OF STATE

[Public Notice 7905]

Notice of Meeting of Advisory Committee on International Law

A meeting of the Advisory Committee on International Law will take place on Wednesday, June 13, 2012, from 9:30 a.m. to approximately 5:30 p.m., at the George Washington University Law School (Michael K. Young Faculty Conference Center, 5th Floor), 2000 H St. NW., Washington, DC. The meeting will be chaired by the Legal Adviser of the Department of State, Harold Hongju Koh, and will be open to the public up to the capacity of the meeting room. It is anticipated that the agenda of the meeting will cover a range of current international legal topics, including the law of immunity, international criminal law, transnational disincentive mechanisms, and future international law priorities for the Office of the Legal Adviser.

Members of the public who wish to attend the session should, by Wednesday, June 5, 2012, notify the Office of the Legal Adviser (telephone: (202) 776–8344, email: *KillTP@state.gov*) of their name, professional affiliation, address, and telephone number. A valid photo ID is required for admittance. A member of the public who needs reasonable accommodation should make his or her request by June 5, 2012. Requests made after that time will be considered but might not be possible to accommodate.

Dated: May 23, 2012.

Theodore P. Kill,

Attorney-Adviser, Office of Claims and Investment Disputes, Office of the Legal Adviser, Executive Director, Advisory Committee on International Law, Department of State.

[FR Doc. 2012–13218 Filed 5–30–12; 8:45 am]

BILLING CODE 4710–08–P

DEPARTMENT OF STATE

[Public Notice 7904]

Overseas Schools Advisory Council Notice of Meeting

The Overseas Schools Advisory Council, Department of State, will hold its Annual Meeting on Thursday, June 21, 2012, at 9:30 a.m. in Conference Room 1107, Department of State Building, 2201 C Street NW., Washington, DC The meeting is open to the public and will last until approximately 12:00 p.m.

The Overseas Schools Advisory Council works closely with the U.S. business community in improving those American-sponsored schools overseas that are assisted by the Department of State and attended by dependents of U.S. Government families and children of employees of U.S. corporations and foundations abroad.

This meeting will deal with issues related to the work and the support provided by the Overseas Schools Advisory Council to the American-sponsored overseas schools. The Council will review progress on an initiative to expand the availability of the World Virtual School. In addition Dr. Andres Alonso, Chief Executive, Baltimore City Public Schools will speak to the Council about his leadership of that education system.

Members of the public may attend the meeting and join in the discussion, subject to the instructions of the Chair. Admittance of public members will be limited to the seating available. Access to the State Department is controlled, and individual building passes are required for all attendees. Persons who plan to attend should advise the office of Dr. Keith D. Miller, Department of State, Office of Overseas Schools, Room H328, SA–1, Washington, DC 20522–0132, telephone 202–261–8200, prior to June 11, 2012. Each visitor will be asked to provide his/her date of birth and either driver's license or passport number at the time of registration and attendance, and must carry a valid photo ID to the meeting.

Personal data is requested pursuant to Public Law 99–399 (Omnibus Diplomatic Security and Antiterrorism

Act of 1986), as amended; Public Law 107–56 (USA PATRIOT Act); and Executive Order 13356. The purpose of the collection is to validate the identity of individuals who enter Department facilities. The data will be entered into the Visitor Access Control System (VACS–D) database. Please see the Privacy Impact Assessment for VACS–D at:*http://www.state.gov/documents/organization/100305.pdf* for additional information.

Any requests for reasonable accommodation should be made at the time of registration. All such requests will be considered, however, requests made after June 11th might not be possible to fill. All attendees must use the C Street entrance to the building.

Dated: May 24, 2012.

Keith D. Miller

Executive Secretary, Overseas Schools Advisory Council.

[FR Doc. 2012–13219 Filed 5–30–12; 8:45 am]

BILLING CODE 4710–24–P

STATE JUSTICE INSTITUTE

SJI Board of Directors Meeting, Notice

AGENCY: State Justice Institute.

ACTION: Notice of meeting.

SUMMARY: The SJI Board of Directors will be meeting on Monday, June 18, 2012 at 1:00 p.m. The meeting will be held at the Westin Hotel in Seattle, Washington. The purpose of this meeting is to consider grant applications for the 3rd quarter of FY 2012, and other business. All portions of this meeting are open to the public.

ADDRESSES: Westin Hotel, 1900 5th Ave., Seattle, WA 98101, 206–728–1000.

FOR FURTHER INFORMATION CONTACT: Jonathan Mattiello, Executive Director, State Justice Institute, 11951 Freedom Drive, Suite 1020, Reston, VA 20190, 571–313–8843, *contact@sji.gov.*

Jonathan D. Mattiello,

Executive Director.

[FR Doc. 2012–13158 Filed 5–30–12; 8:45 am]

BILLING CODE P

DEPARTMENT OF TRANSPORTATION

Office of the Secretary

[Docket No. DOT–OST–2012–0080 (Formerly Docket Number DOT–OST–2008–0182)]

Agency Requests for Renewal of a Previously Approved Information Collection: Small Business Transportation Resource Center (SBTRC) Regional Field Offices Intake Form (DOT F 4500) and SBTRC Regional Field Offices Quarterly Report Form (DOT F 4502)

AGENCY: Office of Small and Disadvantaged Business Utilization (OSDBU), Office of the Secretary of Transportation (OST), DOT.

ACTION: Notice of request for comments.

SUMMARY: The OSDBU invites the public to comment about our intention to request the Office of Management and Budget's (OMB) approval to renew an information collection. The collection involves the use of the SBTRC Regional Field Offices Intake Form (DOT F 4500) and the SBTRC Regional Field Offices Quarterly Report Form (DOT F 4502). On January 31, 2012, OSDBU published a 60-day notice in the **Federal Register** (Vol. 77, No. 20) (Formerly Docket Number DOT–OST–2008–0182), informing the public of OSDBU's intention to extend an approved information collection. The collection involves the use of the Regional Field Offices Intake Form (DOT F 4500), which documents the type of assistance provided to each small business that is enrolled in the program database. The use of the Regional Field Office Quarterly Report Form (DOT F 4502) highlights activities such as counseling, marketing, meetings/conferences, and services to businesses as completed during the quarter. The Quarterly Report Form provides a more composite and comprehensive review of the Field Offices over a longer time frame. The information will be used to ascertain whether the program is providing services to its constituency, the small business community, and is done so in a fair and equitable manner. The information collected is necessary to determine whether small businesses are participating in DOT funded and DOT assisted opportunities.

We are required to publish this notice in the **Federal Register** by the Paperwork Reduction Act of 1995, Public Law 104–13.

DATES: Written comments should be submitted by: July 2, 2012 and submitted to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 Seventeenth Street NW., Washington, DC 20503, Attention: OST Desk Officer. Comments may also be sent via email to OMB at the following address: *oira_submissions@omb.eop.gov.*

FOR FURTHER INFORMATION CONTACT: Arthur D. Jackson, 202–366–5344 or Patricia Martin at 202–366–5337, Office of Small and Disadvantaged Business Utilization, Office of the Secretary, U.S. Department of Transportation, 1200 New Jersey Avenue SE., Room W56 440, Washington, DC 20590. Office hours are from 9:00 a.m. to 5:00 p.m. Eastern Time, Monday through Friday, except Federal holidays.

SUPPLEMENTARY INFORMATION: *Title:* U.S. Department of Transportation, Office of Small and Disadvantaged Business Utilization (OSDBU).

OMB Control No: 2105–0554.

Form No.: DOT F 4500, SBTRC Regional Field Offices Intake Form.

Form No.: DOT F 4502, SBTRC Regional Field Office Quarterly Report Form.

Affected Public: Representatives of OSDBU's SBTRC Regional Field Offices and the Small Business community on a national basis.

Type of Review: Extension of a Currently Approved Collection of Information.

Abstract: In accordance with Public Law 95–507, an amendment to the Small Business Act and the Small Business Investment Act of 1953, OSDBU is responsible for the implementation and execution of DOT activities on behalf of small businesses, in accordance with Sections 8, 15 and 31 of the Small Business Act (SBA), as amended. The Office of Small and Disadvantaged Business Utilization also administers the provisions of Title 49, of the United States Code, Section 332, the Minority Resource Center (MRC) which includes the duties of advocacy, outreach, and financial services on behalf of small and disadvantaged businesses and those certified under CFR 49 parts 23 and or 26 as Disadvantaged Business Enterprises (DBE).

SBTRC's Regional Field Offices will collect information on small businesses, which includes Disadvantaged Business Enterprise (DBE), Women-Owned Small Business (WOB), Small Disadvantaged Business (SDB), 8(a), Service Disabled Veteran Owned Business (SDVOB), Veteran Owned Small Business (VOSB), HubZone, and types of services they seek from the Regional Field Offices. Services and responsibilities of the Field Offices include business analysis, general management and technical assistance and training, business counseling, outreach services/conference participation, short-term loan and bond assistance. The cumulative data collected will be analyzed by the OSDBU to determine the effectiveness of services provided, including counseling, outreach, and financial services. Such data will also be analyzed by the OSDBU to determine agency effectiveness in assisting small businesses to enhance their opportunities to participate in government contracts and subcontracts.

The Regional Field Offices Intake Form, (DOT F 4500) is used to enroll small business clients into the program in order to create a viable database of firms that can participate in government contracts and subcontracts, especially those projects that are transportation related. Each area on the fillable pdf form must be filled in electronically by the Field Offices and submitted every quarter to OSDBU. The Offices will retain a copy of each Intake Form for their records. The completion of the form is used as a tool for making decisions about the needs of the business, such as; referral to technical assistance agencies for help, identifying the type of profession or trade of the business, the type of certification that the business holds, length of time in business, and location of the firm. This data can assist the Field Offices in developing a business plan or adjusting their business plan to increase its ability to market its goods and services to buyers and potential users of their services.

Respondents: SBTRC Regional Field Offices.

Annual Estimated Number of Respondents: 100.

Frequency: The information will be collected quarterly.

Annual Estimated Number of Responses: 400.

Estimated Total Annual Burden on Respondents: 600 hours per year (90 minutes per response to complete each Intake Form).

Background: The Regional Field Offices Quarterly Report Form (DOT F 4502) must be submitted as a quarterly status report by each Field Office of business activities conducted during the three-month timeframe. The form is used to capture activities and accomplishments that were made by the Regional Field Offices during the course of the quarter. In addition, the form includes a data collection section where numbers and hours are reported and a section that is assigned for a written narrative that provides back-up which supports the data.

Activities to be reported are (1) Counseling Activity which identifies the counseling hours provided to businesses, number of new appointments, and follow-up on counseled clients. (2) Activity for Businesses Served identifies the type of small business that is helped, such as a DBE, 8(a), WOB, HubZone, SDB, SDVOB, or VOSB. (3) Marketing Activity includes the name of an event attended by the SBTRC and the role played when participating in a conference, workshop or any other venue that relates to small businesses. (4) Meetings that are held with government representatives in the region, or at the state level, are activities that are reported. (5) Events Hosted by the SBTRC Regional Field Offices, such as small business workshops, financial assistance workshops, matchmaking events, are activities that are reported on a quarterly basis.

Respondents: SBTRC Regional Field Offices.

Annual Estimated Number of Respondents: 100.

Frequency: The information will be collected quarterly.

Annual Estimated Number of Responses: 400.

Estimated Total Annual Burden on Respondents: 1200 hours per year (3 hours per response to complete each Quarterly Report).

Comments are invited on: (a) Whether the proposed collection of information is necessary for the proper performance of the functions of the Department, including whether the information will have practical utility; (b) the accuracy of the Department's estimate of the burden of the proposed information collection; (c) ways to enhance the quality, utility and clarity of the information collection; and d) ways to minimize the burden of the collection of information on respondents, by the use of electronic means, including the use of automated collection techniques or other forms of information technology. The agency will summarize and/or include your comments in the request for OMB's clearance of this information collection.

Authority: The Paperwork Reduction Act of 1995; 44 U.S.C. Chapter 35, as amended; and 49 CFR 1:48.

Issued in Washington, DC, on May 24, 2012.

Patricia Lawton,

DOT PRA Clearance Officer.

[FR Doc. 2012–13199 Filed 5–30–12; 8:45 am]

BILLING CODE 4910–9X–P

DEPARTMENT OF TRANSPORTATION

Office of the Secretary

[Docket: DOT–OST–2012–0078]

Notice of Request for Renewal of Previously Approved Collection; Short Term Lending Program—Application for Loan Guarantee

AGENCY: Office of the Secretary, Department of Transportation (DOT).

ACTION: Notice and request for comments.

SUMMARY: In compliance with the Paperwork Reduction Act of 1995, Public Law 104–13, (44 U.S.C. 3501 et seq.) this notice announces that the Information Collection Request, abstracted below, will be forwarded to the Office of Management and Budget for the renewal of the Short Term Lending Program—Application for Loan Guarantee. A 60 day **Federal Register** Notice (77 FR 14459) was published March 9, 2012 (DOT–OST 2008–0244). The agency did not receive any comments.

DATES: Written comments should be submitted by July 2, 2012 and sent to OMB.

FOR FURTHER INFORMATION CONTACT: Nancy Strine, Manager Financial Assistance Division, Office of Small and Disadvantaged Business Utilization, Office of the Secretary, U.S. Department of Transportation, 1200 New Jersey Avenue SE., Room W56–448, Washington, DC 20590. Phone number 202–366–1930. Fax number 202–366–7228. Office hours are from 8:00 a.m. to 4:30 p.m., Monday through Friday, except Federal holidays.

Comments: Comments should be sent to OMB: Attention DOT/OST Desk Officer, Office of Information and Regulatory Affairs, Office of Management and Budget, Docket Library, 725 17th Street NW., Washington, DC 20503 or fax to: 202–395–5806. Please make reference to OMB Control No. 2104–0555 Docket DOT–OST–2012–0078.

SUPPLEMENTARY INFORMATION:

Title: Short Term Lending Program—Application for Loan Guarantee.

OMB Control No: 2105–0555.

Number of Respondents: 100.

Number of Responses: 100.

Total Annual Burden: 1400.

Abstract: OSDBU's Short Term Lending Program (STLP) offers certified Disadvantaged Business Enterprises (DBEs) and other certified Small Businesses (8a, women-owned, small disadvantaged, HUBZone, veteran owned, and service disabled veteran owned) the opportunity to obtain short term working capital at variable interest rates for transportation-related projects. The STLP provides Participating Lenders (PLs) a guarantee, up to 75%, on a revolving line of credit up to a $750,000 maximum. These loans are provided through lenders that serve as STLP Participating Lenders (PLs). The term on the line of credit is up to one (1) year, which may be renewed for five (5) years. A potential or renewal STLP participant must submit a guaranteed loan application package.

This collection renewal combines two applications, the former ''Short-term Lending Program Application for a New Loan Guarantee'' and the ''Application for Loan Guarantee Renewal'' into one Short Term Lending Program Application for a Loan Guarantee. There should no longer be any confusion since a set of explicit instructions has been added to the application. All attempts have been made to make it easier to read, understand, and use. The application form is now a PDF fillable form. The information collected is used to determine the applicant's eligibility and is necessary to approve or deny a loan. We are required to publish this notice in the **Federal Register** by the Paperwork Reduction Act of 1995.

Respondents: Certified Disadvantaged Business Enterprises (DBEs) and other certified Small Businesses (8a, women-owned, small disadvantaged, HUBZone, veteran owned, and service disabled veteran owned) interested in financing their transportation-related contracts.

DOT Form 2301–1(REV.1). Short Term Lending Program Application for Loan Guarantee: A potential or renewal STLP participant must submit a guaranteed loan application package. The guaranteed loan application includes the STLP application and supporting documentation to be collected from the checklist in the application. The application may be obtained directly from OSDBU, the Regional Small Business Transportation Resource Centers, from a PL, or online from the agency's Web site, currently at *http://www.osdbu.dot.gov/financial/stlp.cfm.*

Respondents: 100.

Frequency: Once.

Estimated Average Burden per Response: 2 hours.

Estimated Total Annual Burden Hours: 200 hours.

Supporting documentation. Required documentation shall include, but is not limited to, the following items:

a. Business, trade, or job performance reference letters;

b. DBE or other eligible certification letters;

c. Aging report of receivables and payables;

d. Business tax returns;

e. Business financial statements;

f. Personal income tax returns;

g. Personal financial statements;

h. Schedule of work in progress (WIP);

i. Signed and dated copy of transportation-related contracts;

j. Business debt schedule;

k. Cash flow projections;

l. Owner(s) and a key management resumes.

Respondents: 100.

Frequency: Once.

Estimated Average Burden per Response: 12 hours.

Estimated Total Annual Burden Hours: 1200 hours.

Title: STLP—Participating Lender (PL) forms.

Number of Respondents: 100.

Number of Responses: 100.

Total Annual Burden: 2925 hours.

Respondents: Participating Lenders that are in the process or have entered into cooperative agreements with DOT's OSDBU under 49 CFR part 22 DOT–OST–2008–0236 entitled, ''Short Term Lending Program''.

Abstract: The Office of the Secretary, Office of Small and Disadvantaged Business Utilization (OSDBU), invites public comments on our intention to request the Office of Management and Budget's (OMB) approval to renew a collection of the STLP Participating Lender (PL) forms. The information collected administers the loans guaranteed under the STLP. The information collected keeps the Participating Lender's (PLs) in compliance with the terms established in the Cooperative Agreement between DOT and the PLs. Every attempt was made to make these forms easier to read, understand, and use.

This renewal collection involves the use of the ''Short Term Lending Program Bank Verification Loan Activation Form''; ''Short Term Lending Program Bank Acknowledgement Extension Request Form''; ''Short Term Lending Program Bank Acknowledgement Loan Close-Out Form''; ''Guaranty Loan Status Report''; ''Pending Loan Status Report''; ''Drug-Free Workplace Act Certification for a Grantee Other than an Individual''; ''Certification Regarding Lobbying for Contracts, Grants, Loans, and Cooperative Agreements''; ''Office of Small and Disadvantaged Business Utilization U.S. Department of Transportation Short Term Lending Program Certification Regarding Debarment, Suspension''; ''Cooperative Agreement between the U.S. Department of Transportation and the Participating Lender''; and ''U.S. Department of Transportation Office of Small and Disadvantaged Utilization Short Term Lending Program Guarantee Agreement''.

DOT Form 2303–1. Short-Term Lending Program Bank Verification Loan Activation Form. The PL Respondent must submit to OSDBU a Loan Activation Form that indicates the date in which the loan has been activated.

Respondents: 100.

Frequency: Annually, up to five years.

Estimated Average Burden per Response: ½ hour.

Estimated Total Annual Burden Hours: 50 hours.

DOT Form 2310–1. Short-Term Lending Program Bank Acknowledgement Extension Request Form. An extension of the original loan guarantee for a maximum period of ninety (90) days may be requested, in writing, by the PL Respondent using the STLP Extension Request Form.

Respondents: 100.

Frequency: Annually, up to five years.

Estimated Average Burden per Response: ½ hour.

Estimated Total Annual Burden Hours: 50 hours.

DOT Form 2304–1. Short-Term Lending Program Bank Acknowledge Loan Close-Out. The PL Respondent must submit to OSDBU a Loan Close-Out Form upon full repayment of the STLP loan or when the loan guarantee expires.

Respondents: 100.

Frequency: Annually, up to five years.

Estimated Average Burden per Response: ½ hour.

Estimated Total Annual Burden Hours: 50 hours.

DOT Form 2305–1. Guaranty Loan Status Report. PL Respondent submits a monthly status of active guaranteed loans to OSDBU.

Respondents: 100.

Frequency: Monthly.

Estimated Average Burden per Response: 1 hour.

Estimated Total Annual Burden Hours: 1200 hours.

DOT Form 2306–1. Pending Loan Status Report. PL Respondent submits monthly loan(s) in process report to OSDBU.

Respondents: 100.

Frequency: Monthly.

Estimated Average Burden per Response: 1 hour.

Estimated Total Annual Burden Hours: 1200 hours.

DOT Form 2307–1. Drug-Free Workplace Act Certification for a Grantee Other than an Individual Form. The PL certifies it is a drug-free workplace by executing this certification.

Respondents: 100.

Frequency: Once.

Estimated Average Burden per Response: 15 minutes.

Estimated Total Annual Burden Hours: 25 hours.

DOT Form 2308–1. Certification Regarding Lobbying for Contracts, Grants, Loans, and Cooperative Agreement. PL Respondent must certify that no Federal funds will be utilized for lobbying by executing this form.

Respondents: 100.

Frequency: Once.

Estimated Average Burden per Response: 15 minutes.

Estimated Total Annual Burden Hours: 25 hours.

DOT Form 2309–1. Certification Regarding Debarment, Suspension Form. The PL Respondent must not currently be debarred or suspended from participation in a government contract or delinquent on a government debt by submitting a current SBA Form 1624 or its equivalent.

Respondents: 100.

Frequency: Once.

Estimated Average Burden per Response: 15 minutes.

Estimated Total Annual Burden Hours: 25 hours.

DOT Form 2313–1. Cooperative Agreement between the United States Department of Transportation and the Bank (Participating Lender). This is the official agreement between the U.S. DOT and the Participating Lender (Bank) which spells out the terms; deliverables; audit, investigation, and review; record retention; duration of agreement; expiration of agreement; suspension of agreement; termination; DOT's representative; and miscellaneous conditions.

Respondents: 100.

Frequency: Every two years.

Estimated Average Burden per Response: 1 hour.

Estimated Total Annual Burden Hours: 100 hours.

DOT Form 2313–2. Cooperative Agreement between the United States Department of Transportation and the Community Development Financial Institution (CDFI). This is the official agreement between the U.S. DOT and the Community Development Financial Institution (CDFI), an eligible Participating Lender or which spells out the terms; Deliverables; Audit, Investigation, and Review; Record Retention; Duration of Agreement; Expiration of Agreement; Suspension of Agreement; Termination; DOT's Representative; and Miscellaneous Conditions.

Respondents: 100.

Frequency: Every two years.

Estimated Average Burden per Response: 1 hour.

Estimated Total Annual Burden Hours: 100 hours.

DOT Form 2314–1. Department of Transportation Office of Small and Disadvantaged Business Utilization (OSDBU) Short Term Lending Program Guarantee Agreement Form. This document is the seventy-five (75%) loan guarantee from the U.S. Department of Transportation to the specific Participating Lender Respondent. It also contains Annex A which is the Participating Lender's default mechanism.

Respondents: 100.

Frequency: Every year.

Estimated Average Burden per Response: 1 hour.

Estimated Total Annual Burden Hours: 100 hours.

Comments are invited on: whether the proposed collection renewal of information is necessary for the proper performance of the functions of the Department, including whether the information will have practical utility; the accuracy of the Department's estimate of the burden of the proposed information collection; ways to enhance the quality, utility and clarity of the information to be collected; and ways to minimize the burden of the collection of information on respondents, including the use of automated collection techniques or other forms of information technology. A comment to OMB is most effective if OMB receives it within 30 days of publication.

Issued in Washington, DC, on May 25, 2012.

Patricia Lawton,

PRA Program Manager, Office of the Secretary, Department of Transportation.

[FR Doc. 2012–13208 Filed 5–30–12; 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 May 19, 2012

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: DOT–OST–2005–20571.

Date Filed: May 18, 2012.

Due Date for Answers, Conforming Applications, or Motion to Modify Scope: June 8, 2012.

Description: Application of Meridiana fly, S.p.A. requesting a foreign air carrier permit and renewal of its exemption in order to engage in the scheduled foreign air transportation of persons, property, and mail: (a) Foreign scheduled and charter air transportation of persons, property and mail from any point or points behind any Member State of the European Union via any point or points in any Member State and via intermediate points to any point or points in the United States and beyond; (b) foreign scheduled and charter air transportation of persons, property and mail between any point or points in the United States and any point or points in any member of the European Common Aviation Area; (c) foreign scheduled and charter all-cargo air transportation between any point or points in the United States and any other point or points; and (d) transportation authorized by any additional route rights made available to European Community carriers in the future.

Renee V. Wright,

Program Manager, Docket Operations, Federal Register Liaison.

[FR Doc. 2012–13181 Filed 5–30–12; 8:45 am]

BILLING CODE 4910–9X–P

DEPARTMENT OF TRANSPORTATION

Federal Highway Administration

Environmental Assessment: Notice of Final Federal Actions on Improvements to U.S. 60 in Union and Henderson Counties, KY

AGENCY: Federal Highway Administration (FHWA), DOT.

ACTION: Notice of limitations on claims for judicial review of actions by FHWA, Army Corps of Engineers (USACE), DoD, and other Federal agencies.

SUMMARY: This notice announces actions taken by the FHWA that are final within the meaning of 23 U.S.C. 139(l)(1). The actions relate to a proposed highway project: the U.S. 60 Capacity and Safety Improvement Project between Morganfield and Henderson in Union and Henderson Counties, Kentucky (KYTC Item Nos. 2–79, 2–122, 2–123).

DATES: By this notice, the FHWA is advising the public of final actions subject to 23 U.S.C. 139(1)(1). A claim seeking judicial review of the Federal agency actions taken on the highway project will be barred unless the claim is filed on or before November 21, 2012. If the Federal law that authorizes judicial review of the a claim provides a time period of less than 180 for filing such claim, then that shorter time period still applies.

FOR FURTHER INFORMATION CONTACT: For FHWA: Mr. Anthony Goodman, Environmental Specialist, Federal Highway Administration, Kentucky Division; 330 West Broadway, Frankfort, Kentucky, 40601; normal business hours Monday–Friday, 8 a.m.–4:30 p.m. Eastern Standard Time; Phone 502–223–6742, Email *Anthony.Goodman@dot.gov.* For KYTC: Mr. David Waldner, P.E., Director, Division of Environmental Analysis, Kentucky Transportation Cabinet; 200 Mero Street, 5th Floor, Frankfort, Kentucky 40622; regular business hours Monday–Friday, 8 a.m.–4:30 p.m. Eastern Standard Time; Phone 502–564–5655, Email: *David.Waldner@ky.gov.*

SUPPLEMENTARY INFORMATION: Notice is hereby given that the FHWA has taken final agency actions subject to 23 U.S.C. 139(0)(1) by issuing licenses, permits, and approvals for the following highway project in the State of Kentucky: The U.S. 60 Capacity and Safety Improvement project involves widening U.S. 60 to the north of the existing roadway between Morganfield and KY 141 (South) in Waverly, a bypass around the south side of Waverly and widening U.S. 60 between Waverly and Highland Creek. At the Highland Creek crossing the project extends northeast on new alignment bypassing Corydon to the west, reconnecting with existing U.S. 60 to widen the remaining 3.7 miles terminating at KY 425, the Henderson Bypass. The roadway will be four lanes with a forty foot depressed grass median with twelve foot outside shoulders and six foot inside shoulders. The purpose of the project is to meet the transportation demands and capacity needs necessary to make the U.S. 60 highway corridor in the area function effectively, and to address safety concerns. The study area is between the cities of Morganfield and Henderson, in Union and Henderson Counties, and U.S. 60 is the only major east-west corridor in this portion of the state.

The actions by the Federal agencies, and the laws under which such actions were taken, are described in the Finding of No Significant Impact (FONSI) for the project, approved on April 9, 2012 (FHWA) and March 22, 2012 (KYTC); and in other documents in the FHWA project records. The Environmental Assessment and FONSI, and other project records are available by contacting FHWA or KYTC at the addresses provided above.

This notice applies to all Federal agency decisions as of the issuance date of this notice and all laws under which such actions were taken, including but not limited to the following:

1. General: National Environmental Policy Act (NEPA) [42 U.S.C. 4321–4351]; Federal-Aid Highway Act [23 U.S.C. 109 and 23 U.S.C. 128]; Public Hearing [23 U.S.C. 128].

2. Air: Clean Air Act [42 U.S.C. 7401–7671(q)].

3. Wildlife: Endangered Species Act [16 U.S.C. 1531–1544].

4. Historic and Cultural Resources: Section 106 of the National Historic Preservation Act of 1966, as amended [16 U.S.C. 470(f) *et seq.*]; Archeological Resources Protection Act of 1977 [16 U.S.C. 470(aa)–470(11)]; Archeological and Historic Preservation Act [16 U.S.C. 469469(c)].

5. Land: Section 4(f) of The Department of Transportation Act: 23 U.S.C. 138, 49 U.S.C. 303; Farmland Protection Policy Act (FPPA) [7 U.S.C. 4201–4209].

6. Social and Economic: Civil Rights Act of 1964 [42 U.S.C. 2000(d)–2000(d)(1)]; Uniform Relocation Assistance and Real Property Acquisition Act of 1970 (42 U.S.C. 4601 *et seq.,* Pub. L. 91–646) as amended by the Uniform Relocation Act Amendments of 1987 (Pub. L. 100–17); Executive Order 12898, Federal Actions to Address Environmental Justice in Minority Populations and Low Income Populations, February 11, 1994.

(Catalog of Federal Domestic Assistance Program Number 20.205, Highway Planning and Construction. The regulations implementing Executive Order 12372 regarding intergovernmental consultation on Federal programs and activities apply to this program.)

Authority: 23 U.S.C. 315; 23 CFR 771.123; 49 CFR 1.48

Issued on: May 22, 2012.

John D. Ballantyne,

Program Delivery Team Leader, Federal Highway Administration.

Frankfort, Kentucky

[FR Doc. 2012–13030 Filed 5–30–12; 8:45 am]

BILLING CODE 4910–22–M

DEPARTMENT OF TRANSPORTATION

Federal Highway Administration

Notice of Availability of the Finding of No Significant Impact: Union and Henderson Counties, KY

AGENCY: Federal Highway Administration (FHWA), DOT.

ACTION: Notice of availability (NOA).

SUMMARY: In accordance with the National Environmental Policy Act and Federal Highway Administration procedures, the FHWA announces the availability of the Finding of No Significant Impact (FONSI) to implement the US 60 Capacity and Safety Improvement Project between Morganfield and Henderson in Union and Henderson Counties, Kentucky. The Division Administrator, FHWA-Kentucky Division signed the FONSI on April 9, 2012.

ADDRESSES: The FHWA FONSI for the US 60 Capacity and Safety Improvement project can be viewed at or copies requested from the Kentucky Transportation Cabinet District 2 office located at 1840 North Main Street Madisonville, KY 42431–5003.

FOR FURTHER INFORMATION CONTACT: Address all comments concerning this notice to Anthony Goodman of the FHWA Kentucky Division at (502) 223–6720 or via email at *Anthony.Goodman@dot.gov.* For additional information, contact Everett Green, P.E., Project Manager for the Kentucky Transportation Cabinet, at (270) 824–7080 or via email at *Everett.Green@ky.gov.*

SUPPLEMENTARY INFORMATION: The US 60 Capacity and Safety Improvement project FONSI was developed following the preparation of an Environmental Assessment in accordance with the National Environmental Policy Act (NEPA) and solicitation of comment from both the public and interested local, state and federal agencies. The decision is hereby made to implement the project that involves widening US 60 to the north of the existing roadway between Morganfield and KY 141 (South) in Waverly, a bypass around the south side of Waverly and widening US 60 between Waverly and Highland Creek. At the Highland Creek crossing the project extends northeast on new alignment bypassing Corydon to the west, reconnecting with existing US 60 to widen the remaining 3.7 miles terminating at KY 425, the Henderson Bypass. The roadway will be four lanes with a forty foot depressed grass median with twelve foot outside shoulders and six foot inside shoulders. The purpose of the project is to meet the transportation demands and capacity needs necessary to make the US 60 highway corridor in the area function effectively, and to address safety concerns. The study area is between the cities of Morganfield and Henderson, in Union and Henderson Counties, and US 60 is the only major east-west corridor in this portion of the state.

Section 106 coordination resulted in a Section 106 Memorandum of Agreement to address mitigation for historic resources. The project results in a Section 4(f) impact; replacement of the historic US 60 bridge over Highland Creek. This Finding of No Significant Impact (FONSI) is based on the Environmental Assessment (EA) which has been independently evaluated by the FHWA and determined to adequately and accurately discuss the need, environmental issues, and impacts of the proposed project and appropriate mitigation measures. It provides sufficient evidence and analysis for determining that an EIS is not required. The FHWA takes full responsibility for the accuracy, scope, and content of the EA, FONSI, and other supporting documents.

Authority: 23 U.S.C. 315; 23 CFR 771.123; 49 CFR 1.48

Issued on: May 22, 2012.

John Ballantyne,

Program Delivery Team Leader, Federal Highway Administration Frankfort, Kentucky.

[FR Doc. 2012–13035 Filed 5–30–12; 8:45 am]

BILLING CODE 4910–22–M

DEPARTMENT OF TRANSPORTATION

Federal Transit Administration

Innovative Transit Workforce Development Program

AGENCY: Federal Transit Administration (FTA), DOT.

ACTION: Notice of funding availability (NOFA) for innovative workforce development program.

SUMMARY: The Federal Transit Administration (FTA) is publishing a Notice of Funding Availability (NOFA) for the Innovative Workforce Development Program. This NOFA seeks proposals that promote diverse and innovative successful workforce development models and programs. FTA has budgeted approximately $5,000,000 for providing support of these efforts.

DATES: Complete proposals must be submitted to *http://www.grants.gov* no later than 11:59 p.m. EDT, July 6, 2012.

ADDRESSES: All proposals must be submitted electronically via *http://www.grants.gov*. Prospective applicants are advised to initiate the process by registering on this site immediately to ensure the completion of the application process prior to the submission deadline.

FOR FURTHER INFORMATION CONTACT: Betty Jackson, FTA Office of Research and Innovation, 1200 New Jersey Avenue SE., Washington, DC 20590. Phone: (202) 366–1730. Email: *Betty.Jackson@dot.gov*. TDD service is available via 1–800–877–8339 (TDD/FIRS).

SUPPLEMENTARY INFORMATION:

Table of Contents

I. Background and Objectives

FTA's workforce development activities are authorized by 49 U.S.C. 5322, Human Resource Programs. The Innovative Transit Workforce Development Program is intended to exercise this authority by providing funding to transit agencies and other entities with innovative solutions to pressing workforce development issues.

Supporting a highly-skilled transit workforce is critical to maintaining a competitive and efficient public transportation system. As public transportation enjoys a resurgence in the United States and investments continue in the physical capital of the nation's transit systems, it is essential to build and maintain human capital as well.

Type of Workforce Development Activity

FTA will accept applications that target one or more the following areas in the lifecycle of the transit workforce:

(1) Pre-employment training/preparation

(2) Recruitment and hiring

(3) Incumbent worker training and retention

(4) Succession planning/phased retirement

Project Focus

All workforce development activities that focus on these activity areas in the lifecycle of the transit workforce are eligible.

FTA is soliciting applications which cover a wide range of workforce activities—however, the following areas are of particular interest and focus:

(a) Projects or programs that demonstrate innovative methods of leveraging investments in public transportation infrastructure to generate positive impacts in local employment, particularly in underserved communities.

(b) Innovative projects or programs that support the training/professional development needs of blue-collar operations and maintenance workers, particularly in the area of new and emerging technologies.

(c) Projects that support or showcase innovative methods of encouraging youth to pursue careers in public transportation.

Competitive proposals will support products and approaches that improve the state of the practice in workforce development.

Funding can be used for new workforce ideas and programs *or* to augment an existing workforce effort. While either type of effort will be considered, programs or approaches with an existing track record of success are likely to receive significant consideration.

Proposals *must* describe the final project deliverable(s) and how they will improve the state of the practice. Final products and project deliverables will be made available at no cost to FTA and other parties at the project's close.

II. Award Information

A. Award Amount

FTA has budgeted approximately $5,000,000 for the program in its second iteration of the program. Future funding will depend on Congressional appropriation. Proposals must have a minimum threshold of $100,000 and a maximum of $1,000,000. FTA reserves the right to change this amount based on the quantity and quality of applications submitted under this Request for applications (RFA). FTA may choose to fund programs for less than the proposed amount. Applicants are encouraged to submit proposals for projects at the appropriate funding level for the project, recognizing that FTA's contributions will be limited according to the funding range specified above.

B. Period of Performance

The period of performance will be up to 18 months from the date of execution of the grant documents. This performance period includes all necessary implementation and start-up activities, execution of the program, and completion of final deliverables as specified in the applicant's Scope of Work.

The Department intends that all recipients implement the programs awarded as soon as possible. Applicants should plan to fully expend grant funds during the period of performance, recognizing that full transparency and accountability are required for all expenditures.

• FTA anticipates awarding proposals for projects that will be completed within 12 to 18 months of receipt of the funding award.
• Applicants may choose to submit more than one proposal. However, each proposal must support a new idea or program and not be duplicative. A volume of proposals from a single entity or a consortium will not increase that entity's chances of being awarded a grant.
• FTA may choose to fund only a part of a proposed project or none at all.
• FTA will also consider projects of longer duration, provided that the work activities and product delivery is phased in such a way as to produce a viable product during the period of performance specified in this RFA.
• Upon award, FTA may withdraw its obligation to provide Federal assistance if the recipient does not submit the formal application (to be completed after selection) within 90 days following the date of the offer.

Deadlines: Applications must be submitted through GRANTS.GOV (*http://www.grants.gov/*) by July 6, 2012. FTA suggests that applicants commence the application process well ahead of the application deadline in case of technical difficulty or other extenuating circumstances. Late applications will not be accepted.

III. Eligibility Information

A. Eligible Applicants Defined

Eligible applicants are public transit agencies; state departments of transportation (DOTs) providing public transportation services; and Indian tribes, non-profit institutions and institutions of higher education. Only these types of organizations are eligible to apply to this program.

The cooperative agreement will be between FTA and the selected organization, which must have a substantial involvement in the project and must not simply act as a pass-through for funds.

Applicants may apply individually or in a consortium of eligible applicants. The consortium of eligible applicants must designate a lead applicant as the primary recipient of federal funds.

Individuals, private for-profit entities, and Federal agencies are not eligible to apply to this program. However, personnel in private for-profit entities may participate as a non-compensated partner or through sub-contracts with the awardees.

B. Strategic Partnerships

To be eligible for funding under this NOFA, applicants must demonstrate that the proposed project is supported by both the primary applicant and at least one or more external partner(s). The permitted external partners may differ based on the type of lead applicant, *as noted below.*

a. Lead Applicant Is: Nonprofit or Institution of Higher Education

If a non-profit organization or an institution of higher education is the lead applicant, then it must partner with a transit agency or consortium of transit agencies, a state department of transportation (State DOT) providing public transportation services, or an Indian tribe providing transportation services. A particular transit agency or other entity providing public transportation services may be a strategic partner for more than one applicant. However, any participation as a strategic partner must be substantial and include significant project involvement.

Applicants should include a letter of confirmed support from each potential partner as part of their application.

b. Lead Applicant Is: Public Transit Agency; State Departments of Transportation (State DOT)s Providing Public Transportation Services; or Indian Tribe

If a transit agency or other entity providing public transportation services is the lead applicant, then they must partner with an external strategic partner. Strategic partnerships should be clearly defined and limited to partner entities with a substantial interest and involvement in the project.

An external partner entity may be defined as, but not limited to:

1. Educational institutions, which includes entities providing professional accreditation, degree, and/or certification programs, such as universities, community colleges, or trade schools, either non-profit or for-profit.
2. Public workforce investment systems, such as local Workforce Investment Boards and their one-stop systems.
3. Labor organizations, such as labor unions and labor management organizations.
4. Non-profit organizations that support the mission of transit and transportation workforce development.

C. Cost Sharing

Cost sharing or local matching funds are not required as a condition for application, but leveraged resources are strongly encouraged and may affect an applicant's final score.

D. Other Eligibility Requirements

i. Allowable Activities

Projects must provide direct support to workforce development projects. Capital expenses *such as equipment purchases* are not considered to be eligible costs unless they directly relate to the workforce development program being supported by FTA funds. Acceptable costs can include, but are not limited to: Faculty/instructors, including salaries and fringe benefits, support staff, classroom space, books, materials and supplies, transportation stipends for students.

ii. Unallowable Costs

FTA funds under this program are not intended as an offset to regular *transit agency* employee salaries and may not be used to cover the regular or overtime salaries of employees at transit agencies *offering training.* Funds may be used to cover the costs of staff directly engaged in a program management or training role at an agency.

IV. Proposal Preparation and Submission Instructions

Potential applicants are advised to familiarize themselves with the application process on *http://www.grants.gov* well before the submission deadline. Eligible entities *must* have or must secure a DUNS number for the purposes of formal application and potential entry into a cooperative agreement with FTA. The DUNS number is a unique nine-character number that identifies your organization. It is a tool of the federal government to track how federal money is distributed. Each FTA applicant's DUNS number will be maintained as part of the applicant's profile. This number can be obtained free through the D&B Web site (*http://www.dnb.com/US/duns_update/*).

In addition, each entity that applies and does not have an exemption under 2 CFR 25.110 should:

(1) Be registered in the Central Contractor Registration (CCR) prior to submitting an application or plan (*http://www.ccr.gov*), and

(2) Maintain an active CCR registration with current information at all times during which it has an active Federal award or an application or plan under consideration by an agency;

The applicant should submit a project narrative statement describing the project objectives, proposed work tasks, outputs, and benefits of the proposed project for which Federal assistance is being requested.

If the project is a proposal seeking support for an existing program, it should describe the proposed FTA-supported project within the context of the larger effort.

The narrative should also indicate whether matching funds would be provided, the expected duration of the project, and other information that would assist FTA to understand and evaluate the project. Each submission for a project narrative statement should not exceed 12 pages (single-spaced, single-sided, 12 point font on 8.5 x 11 inch paper) and must include the information listed below:

a. Project Title, Objective(s), and Contact Person. At the top of the document, state the title of the project and provide 2–3 sentences describing the intended project goals and outcomes. List the contact person for this application along with his or her address, title, phone number, fax number, and email address.

b. Statement of the Problem(s). Provide a description of the new or existing program to be supported by the proposed project. Characterize the workforce issue or problem present in the public transportation industry that the project directly addresses. Describe how the project will specifically address the issue for the applying organization. Explain why the specified approach is being taken as opposed to others, and how its innovative aspects have potential for nationwide application. In addition to innovative workforce practices, cite the unique features of the project, such as design or technological innovations, reductions in cost or time, environmental benefits, benefits to riders, or social and community involvement. Finally, identify uncertainties and external factors that could affect the schedule, cost, or success of the program. Supporting documentation may be provided as an attachment that will not count toward the total page limit. Such information will be considered supplementary and will not necessarily be considered by FTA in the project selection process.

c. Geographic Location, Target Groups, and Emphasis Areas. Give a precise location of the project and identify the area(s), and target group(s) to be directly served by the proposed effort. Maps or other graphic aids may be attached as needed.

d. Strategic Partners. Provide a list of the strategic partner(s) that will be participating in the project, as well as a description of each organization, the unique skill sets and capacity they will bring to the project, as well as the activities they will carry out.

e. Scope. Outline a plan of action, organized by work task, pertaining to the scope and detail of how the proposed work will be accomplished. List estimated milestone dates for major activities and products.

Activities should be justified in terms of eligible program activities and proposals should clearly demonstrate the connection between the planned work and at least one of the specific program activities cited.

The scope should also address supporting activities, such as marketing plans for engaging participants and/or dissemination strategies for sharing the results, if such are critical to the success of the supported program.

The applicant must plan to produce at least one final deliverable that will become available to FTA at the end of the project for dissemination and sharing throughout the industry at no cost. Acceptable final products include, but are not limited to, class materials, Web sites or software, recruitment materials, flyers, brochures and reports. This product is in addition to the performance measurement reporting requirements described below in paragraph g.

If a phased plan is being proposed, describe the context and additional phases on a separate page or separate pages.

e. Period of Performance. Provide a schedule for completion of tasks assuming a total period of performance of 12–18 months. If a proposal specifies work that will exceed 18 months from award to delivery of outputs, the proposal must segment the work into phases and identify discrete deliverables that will be completed during the period of performance of this program. If a phased plan is being proposed, describe schedule for additional phases on a separate page or separate pages (not counted toward the page maximum).

f. Cost/Budget Proposal. Provide a cost proposal indicating staffing levels, hours, and direct costs for the total project and amount of funding requested from FTA. As appropriate, the cost proposal should also show the nature and value of in-kind resources that team members will contribute. The proposal should also describe the source, purpose and amount of matching funds that will be used to make up any monetary difference between FTA's contribution and the total project cost.

If a project or program is scalable or can be phased, that should be indicated within the budget. As funding for the Innovative Workforce Development Program is limited, an application that can be scaled may receive additional consideration for funding.

g. Performance Measurement. Provide an approach for demonstrating the local and/or nationwide impact of the pilot project on the transit industry. The proposal should include a description of the applicant's plan for recording the outcomes and reporting at the minimum the following to FTA at the end of the project:

- The number of individuals affected by the project. Applicants should define ''affected individuals'' in terms that make sense for the proposed project.
  - For example, other common reported outcomes include:
    - Number of eligible individuals entered into program
    - Number of successful completers (completed training program, achieved applicable credential, etc.)
    - Number of placed new workers and/or advanced incumbent workers
    - Number of retained workers after 90 days
- The costs of the project and the share of federal investment;
- At least one measure of quality; Quantitative metrics are preferred, but qualitative metrics will be considered provided they are based on the experiences of those affected by the program (as opposed to the self-assessment of the applicant or partner agencies). Metrics could include, but are not limited to, survey results; exit interviews; longitudinal tracking of staff (during the period of performance only);
- A 1–2 page project description that will state the pilot project's initial goals and achievements against those goals. This statement can also include ''lessons learned.''
- A 1–2 page statement of applicability to other entities. Once the program is complete, the applicant will be asked to describe how the pilot project could be scaled and/or altered for application elsewhere, and what types of benefits could be realized by doing so.
- Any other performance measure that the applicant thinks would describe the strengths and weaknesses of the project.

As part of the proposal, provide projections (for quantitative measures) or short hypotheses (for qualitative measures) of what type of impact/ performance FTA could expect from the project.

h. Project Management. Describe the applicant's approach for managing and staffing the project, including the distribution of responsibilities among partner entities and an organizational chart, if applicable. Include responsibilities such as regular reporting, performance measurement, and technical/management interactions with FTA. Quarterly cost and activity progress reporting will be required using a template provided by FTA.

i. Project Staff. List each organization, operator, consultant, or other key individuals who will work on the project, along with short descriptions of their appropriate technical expertise and experience (such as past, relevant research). Attach resumes or curriculum vitae if available. Project staff resumes or curriculum vitae will not count towards the total page count for proposal submissions.

V. Project Selection Criteria

In addition to other FTA staff that may review the proposals, a technical evaluation committee will review proposals under the project selection criteria. Members of the technical evaluation committee and other involved FTA staff reserve the right to screen and rate the applications it receives and to seek clarification from any applicant about any statement in its application that FTA finds ambiguous and/or to request additional documentation to be considered during the evaluation process to clarify information contained within the proposal.

After consideration of the finds of the technical evaluation committee, the FTA Administrator will determine the final selection and amount of funding for each project. FTA may consider geographic diversity and the applicant's receipt of other discretionary awards in its award decisions.

In addition to the general considerations mentioned above, projects will be selected based on the following criteria:

- National Applicability
- Statement of Need
- Innovation
- Project Management and Organizational Capacity
- Strategy and Project Work Plan
- Outcomes and Deliverables
- Support for needs of blue collar operations and maintenance workers

National Applicability

The project should have national or regional applicability and provide a replicable model of workforce development practices.

Statement of Need

An applicant must fully demonstrate a clear and specific industry need for the Federal investment in the proposed transit workforce development activities. An applicant must submit data and provide evidence of the industry need and value for proposed program.

Innovation

A project should identify a unique, significant, or innovative approach to address workforce development issues in a transit agency or state DOT.

Project Management and Organizational Capacity

An applicant must fully describe the capacity of the applicant and its required partners to effectively staff the proposed initiative and deliver the proposed outcomes. The application must also fully describe the applicant's fiscal, administrative, and performance management capacity to implement the key components of this project, and the track record of the applicant and its required partners in implementing projects of similar focus, size, and scope.

Strategy and Project Work Plan

An applicant must provide a comprehensive project work plan. Factors considered in evaluating the project work plan will include: (1) The presentation of a coherent plan that demonstrates the applicant's complete understanding of all the activities, responsibilities, and costs required to implement each phase of the project and achieve projected outcomes; (2) the demonstrated feasibility and reasonableness of the timeline for accomplishing all necessary implementation activities, including the ability to expeditiously begin training; and (3) the extent to which the budget aligns with the proposed work plan and is justified with respect to the adequacy and reasonableness of resources requested.

Deliverables

An applicant must demonstrate a results-oriented approach to managing and operating its project by providing projections for all applicable outcome categories relevant to measuring the success or impact of the project, describing the products and deliverables that will be produced as a result of the grant activities, and fully demonstrating the appropriateness and feasibility of achieving these results. The applicant must include projected outcomes, which will be used as goals for the grant.

Support for the Needs of Blue Collar Operations and Maintenance Workers

Special consideration will be given to innovative projects or programs that support the training/professional development needs of blue-collar operations and maintenance workers, particularly in the area of new and emerging technologies.

VI. Award Administration Information

a. Notification. After FTA has selected the proposals to be funded, successful applicants may be notified informally by email or telephone of their status.

A package containing a formal award letter, instructions for entering into a cooperative agreement with FTA, copies of agreements for execution, and an approved budget will be sent to organizations (listed point of contact) whose submitted proposals have been selected for funding under the program. The ''award letter'' will indicate the date of the award and set forth any special conditions under which the project is approved. The date of award is the date that authorizes the recipient to incur project costs. Any activities that occur before this award are not eligible for reimbursement.

b. Execution of the FTA Agreement. The recipient should execute and date the copies in accordance with the instructions provided in the award package, and return two signed copies of the FTA agreement to the FTA Office of Chief Counsel per the instructions. FTA should be advised promptly if the recipient is unable to execute the FTA agreement within 90 days after the obligation date, (i.e., the date on which FTA officially approved a project).

c. Start Date and Incurred Costs. Absent special circumstances, costs incurred prior to FTA award are not eligible as project expenses. Absent highly unusual circumstances, FTA cannot retroactively approve a project. The recipient may begin to incur project costs as of the date the award letter is signed by FTA and submitted to the awardee for signature.

VII. Additional Information

Prospective applicants may also wish to visit the following Web sites for more information:

- *http://www.fta.dot.gov.*
- For more on managing projects in accordance with FTA Circular 6100.1D: Transit Research and Technology Programs: Application Instructions and Program Management Guidelines: *http://fta.dot.gov/legislation_law/*

12349_12669.html. This includes requirements on project management and administration including quarterly reporting, financial management, and payment.

Issued on: May 25, 2012.

Peter Rogoff,

Administrator.

[FR Doc. 2012–13220 Filed 5–30–12; 8:45 am]

BILLING CODE 4910–57–P

DEPARTMENT OF TRANSPORTATION

Surface Transportation Board

[STB Ex Parte No. 702]

Notification of Trails Act Agreement/Substitute Sponsorship

AGENCY: Surface Transportation Board.

ACTION: Notice of OMB approval of information collection.

SUMMARY: Pursuant to the Paperwork Reduction Act, 44 U.S.C. 3501–3519 (PRA), and Office of Management and Budget (OMB) regulations at 5 CFR 1320.11, the Surface Transportation Board has obtained OMB approval for the collection of information adopted by the Board in *National Trails System Act and Railroad Rights-of-Way,* STB Ex Parte No. 702 (STB served Apr. 30, 2012) (77 FR 25910 (5/2/2012)).

This collection, which is codified at 49 CFR 1152.29, has been assigned OMB Control No. 2140–0017. Unless renewed, OMB approval expires on May 31, 2015. The display of a currently valid OMB control number for this collection is required by law. Under the PRA and 5 CFR 1320.8, 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 OMB control number.

Dated: May 25, 2012.

Jeffrey Herzig,

Clearance Clerk.

[FR Doc. 2012–13177 Filed 5–30–12; 8:45 am]

BILLING CODE 4915–01–P

DEPARTMENT OF THE TREASURY

Fiscal Service

Reinsuring Companies Acceptable On Federal Bonds: Alterra Reinsurance USA, Inc.

AGENCY: Financial Management Service, Fiscal Service, Department of the Treasury.

ACTION: Notice.

SUMMARY: This is Supplement No. 20 to the Treasury Department Circular 570, 2011 Revision, published July 1, 2011, at 76 FR 38892.

FOR FURTHER INFORMATION CONTACT: Surety Bond Branch at (202) 874–6850.

SUPPLEMENTARY INFORMATION: A Certificate of Authority as an acceptable reinsurer on Federal bonds is hereby issued under 31 U.S.C. 9305 to the following company:

Alterra Reinsurance USA, Inc. (NAIC # 10829). BUSINESS ADDRESS: 535 Springfield Avenue, Summit, NJ 07901. PHONE: (908) 630–2700. UNDERWRITING LIMITATION b/: $67,648,000. INCORPORATED IN: Connecticut.

Federal bond-approving officers should annotate their reference copies of the Treasury Circular 570 (''Circular''), 2011 Revision, to reflect this addition.

Certificates of Authority expire on June 30th each year, unless revoked prior to that date. The Certificates are subject to subsequent annual renewal as long as the companies remain qualified (see 31 CFR part 223). A list of qualified companies is published annually as of July 1st in the Circular, which outlines details as to the underwriting limitations, areas in which companies are licensed to transact surety business, and other information.

The Circular may be viewed and downloaded through the Internet at *http://www.fms.treas.gov/c570.*

Questions concerning this Notice may be directed to the U.S. Department of the Treasury, Financial Management Service, Financial Accounting and Services Division, Surety Bond Branch, 3700 East-West Highway, Room 6F01, Hyattsville, MD 20782.

Dated: May 18, 2012.

Laura Carrico,

Director, Financial Accounting and Services Division.

[FR Doc. 2012–13044 Filed 5–30–12; 8:45 am]

BILLING CODE 4810–35–M

DEPARTMENT OF THE TREASURY

Bureau of the Public Debt

Proposed Collection: Comment Request

ACTION: Notice and request for comments.

SUMMARY: The Department of the Treasury, as part of its continuing effort to reduce paperwork and respondent burden, invites the general public and other Federal agencies to take this opportunity to comment on proposed and/or continuing information collections, as required by the Paperwork Reduction Act of 1995, Public Law 104–13 (44 U.S.C. 3506(c)(2)(A). Currently the Bureau of the Public Debt within the Department of the Treasury is soliciting comments concerning the Claim for Lost, Stolen, or Destroyed United States Registered Securities.

DATES: Written comments should be received on or before July 30, 2012 to be assured of consideration.

ADDRESSES: Direct all written comments to Bureau of the Public Debt, Bruce A. Sharp, 200 Third Street A4–A, Parkersburg, WV 26106–1328, or *bruce.sharp@bpd.treas.gov.* The opportunity to make comments online is also available at *www.pracomment.gov.*

FOR FURTHER INFORMATION CONTACT: Requests for additional information or copies should be directed to Bruce A. Sharp, Bureau of the Public Debt, 200 Third Street A4–A, Parkersburg, WV 26106–1328, (304) 480–8150.

SUPPLEMENTARY INFORMATION:

Title: Claim for Lost, Stolen, or Destroyed United States Registered Securities.

OMB Number: 1535–0014.

Form Number: PD F 1025.

Abstract: The information is requested to establish ownership and support a request for relief due to the loss, theft, or destruction of United States Registered Securities.

Current Actions: None.

Type of Review: Extension.

Affected Public: Individuals or Households.

Estimated Number of Respondents: 500.

Estimated Time per Respondent: 55 minutes.

Estimated Total Annual Burden Hours: 460.

Request for Comments: Comments submitted in response to this notice will be summarized and/or included in the request for OMB approval. All comments will become a matter of public record. Comments are invited on: (a) Whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimate of the burden of the collection of information; (c) ways to enhance the quality, utility, and clarity of the information to be collected; (d) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology; and (e) estimates of capital or start-up costs and costs of operation, maintenance, and purchase of services to provide information.

Dated: May 25, 2012.

Bruce A. Sharp,

Bureau Clearance Officer.

[FR Doc. 2012–13170 Filed 5–30–12; 8:45 am]

BILLING CODE 4810–39–P

DEPARTMENT OF THE TREASURY

Bureau of the Public Debt

Proposed Collection: Comment Request

ACTION: Notice and request for comments.

SUMMARY: The Department of the Treasury, as part of its continuing effort to reduce paperwork and respondent burden, invites the general public and other Federal agencies to take this opportunity to comment on proposed and/or continuing information collections, as required by the Paperwork Reduction Act of 1995, Public Law 104–13 (44 U.S.C. 3506(c)(2)(A). Currently the Bureau of the Public Debt within the Department of the Treasury is soliciting comments concerning the Certificate of Identity.

DATES: Written comments should be received on or before July 30, 2012 to be assured of consideration.

ADDRESSES: Direct all written comments to Bureau of the Public Debt, Bruce A. Sharp, 200 Third Street A4–A, Parkersburg, WV 26106–1328, or *bruce.sharp@bpd.treas.gov.* The opportunity to make comments online is also available at *www.pracomment.gov.*

FOR FURTHER INFORMATION CONTACT: Requests for additional information or copies should be directed to Bruce A. Sharp, Bureau of the Public Debt, 200 Third Street A4–A, Parkersburg, WV 26106–1328, (304) 480–8150.

SUPPLEMENTARY INFORMATION:

Title: Certificate of Identity.

OMB Number: 1535–0048.

Form Number: PD F 0385.

Abstract: The information is requested to establish the identity of the owner of the United States Savings Securities.

Current Actions: None.

Type of Review: Revision.

Affected Public: Individuals or Households.

Estimated Number of Respondents: 5,000.

Estimated Time per Respondent: 10 minutes.

Estimated Total Annual Burden Hours: 833.

Request For Comments: Comments submitted in response to this notice will be summarized and/or included in the request for OMB approval. All comments will become a matter of public record. Comments are invited on: (a) Whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimate of the burden of the collection of information; (c) ways to enhance the quality, utility, and clarity of the information to be collected; (d) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology; and (e) estimates of capital or start-up costs and costs of operation, maintenance, and purchase of services to provide information.

Dated: May 25, 2012.

Bruce A. Sharp,

Bureau Clearance Officer.

[FR Doc. 2012–13173 Filed 5–30–12; 8:45 am]

BILLING CODE 4810–39–P

DEPARTMENT OF THE TREASURY

Bureau of the Public Debt

Proposed Collection: Comment Request

ACTION: Notice and request for comments.

SUMMARY: The Department of the Treasury, as part of its continuing effort to reduce paperwork and respondent burden, invites the general public and other Federal agencies to take this opportunity to comment on proposed and/or continuing information collections, as required by the Paperwork Reduction Act of 1995, Public Law 104–13 (44 U.S.C. 3506(c)(2)(A). Currently the Bureau of the Public Debt within the Department of the Treasury is soliciting comments concerning the Description of United States Savings Bonds/Notes and Description of United States Savings Bonds Series HH/H.

DATES: Written comments should be received on or before July 30, 2012 to be assured of consideration.

ADDRESSES: Direct all written comments to Bureau of the Public Debt, Bruce A. Sharp, 200 Third Street A4–A, Parkersburg, WV 26106–1328, or *bruce.sharp@bpd.treas.gov.* The opportunity to make comments online is also available at *www.pracomment.gov.*

FOR FURTHER INFORMATION CONTACT: Requests for additional information or copies should be directed to Bruce A. Sharp, Bureau of the Public Debt, 200 Third Street A4–A, Parkersburg, WV 26106–1328, (304) 480–8150.

SUPPLEMENTARY INFORMATION:

Titles: Description of United States Savings Bonds/Notes and Description of United States Savings Bonds Series HH/H.

OMB Number: 1535–0064.

Form Numbers: PD F 1980 and PD F 2490.

Abstract: The information is requested to establish ownership and support a request for relief due to the loss, theft, or destruction of United States Bearer Securities.

Current Actions: None.

Type of Review: Revision.

Affected Public: Individuals or Households.

Estimated Number of Respondents: 8,000.

Estimated Time per Respondent: 6 minutes.

Estimated Total Annual Burden Hours: 800.

Request for Comments: Comments submitted in response to this notice will be summarized and/or included in the request for OMB approval. All comments will become a matter of public record. Comments are invited on: (a) Whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimate of the burden of the collection of information; (c) ways to enhance the quality, utility, and clarity of the information to be collected; (d) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology; and (e) estimates of capital or start-up costs and costs of operation, maintenance, and purchase of services to provide information.

Dated: May 25, 2012.

Bruce A. Sharp,

Bureau Clearance Officer.

[FR Doc. 2012–13175 Filed 5–30–12; 8:45 am]

BILLING CODE 4810–39–P

DEPARTMENT OF THE TREASURY

Bureau of the Public Debt

Proposed Collection: Comment Request

ACTION: Notice and request for comments.

SUMMARY: The Department of the Treasury, as part of its continuing effort to reduce paperwork and respondent burden, invites the general public and other Federal agencies to take this opportunity to comment on proposed and/or continuing information collections, as required by the Paperwork Reduction Act of 1995, Public Law 104–13 (44 U.S.C. 3506(c)(2)(A)). Currently the Bureau of the Public Debt within the Department of the Treasury is soliciting comments concerning the Affidavit By Individual Surety.

DATES: Written comments should be received on or before July 30, 2012 to be assured of consideration.

ADDRESSES: Direct all written comments to Bureau of the Public Debt, Bruce A. Sharp, 200 Third Street A4–A, Parkersburg, WV 26106–1328, or *bruce.sharp@bpd.treas.gov.* The opportunity to make comments online is also available at *www.pracomment.gov*

FOR FURTHER INFORMATION CONTACT: Requests for additional information or copies should be directed to Bruce A. Sharp, Bureau of the Public Debt, 200 Third Street A4–A, Parkersburg, WV 26106–1328, (304) 480–8150.

SUPPLEMENTARY INFORMATION:

Title: Affidavit By Individual Surety.

OMB Number: 1535–0100.

Form Number: PD F 4094.

Abstract: The information is requested to support a request to serve as surety for an indemnification agreement on a Bond of Indemnity.

Current Actions: None.

Type of Review: Extension.

Affected Public: Individuals or Households.

Estimated Number of Respondents: 500.

Estimated Time Per Respondent: 55 minutes.

Estimated Total Annual Burden Hours: 460.

Request for Comments: Comments submitted in response to this notice will be summarized and/or included in the request for OMB approval. All comments will become a matter of public record. Comments are invited on: (a) Whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimate of the burden of the collection of information; (c) ways to enhance the quality, utility, and clarity of the information to be collected; (d) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology; and (e) estimates of capital or start-up costs and costs of operation, maintenance, and purchase of services to provide information.

Dated: May 25, 2012.

Bruce A. Sharp,

Bureau Clearance Officer.

[FR Doc. 2012–13176 Filed 5–30–12; 8:45 am]

BILLING CODE 4810–39–P

DEPARTMENT OF THE TREASURY

Bureau of the Public Debt

Proposed Collection: Comment Request

ACTION: Notice and request for comments.

SUMMARY: The Department of the Treasury, as part of its continuing effort to reduce paperwork and respondent burden, invites the general public and other Federal agencies to take this opportunity to comment on proposed and/or continuing information collections, as required by the Paperwork Reduction Act of 1995, Public Law 104–13 (44 U.S.C. 3506(c)(2)(A). Currently the Bureau of the Public Debt within the Department of the Treasury is soliciting comments concerning the Affidavit of Forgery for United States Savings Bonds.

DATES: Written comments should be received on or before July 30, 2012 to be assured of consideration.

ADDRESSES: Direct all written comments to Bureau of the Public Debt, Bruce A. Sharp, 200 Third Street A4–A, Parkersburg, WV 26106–1328, or *bruce.sharp@bpd.treas.gov.* The opportunity to make comments online is also available at *www.pracomment.gov*

FOR FURTHER INFORMATION CONTACT: Requests for additional information or copies should be directed to Bruce A. Sharp, Bureau of the Public Debt, 200 Third Street A4–A, Parkersburg, WV 26106–1328, (304) 480–8150.

SUPPLEMENTARY INFORMATION:

Title: Affidavit of Forgery for United States Savings Bonds States Savings Bonds Series.

OMB Number: 1535–0067.

Form Number: PD F 0974.

Abstract: The information is requested to establish whether the registered owner signed the request for payment or if the signature was a forgery.

Current Actions: None.

Type of Review: Extension.

Affected Public: Individuals or households.

Estimated Number of Respondents: 2,500.

Estimated Time per Respondent: 15 minutes.

Estimated Total Annual Burden Hours: 625.

Request for Comments: Comments submitted in response to this notice will be summarized and/or included in the request for OMB approval. All comments will become a matter of public record. Comments are invited on: (a) Whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimate of the burden of the collection of information; (c) ways to enhance the quality, utility, and clarity of the information to be collected; (d) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology; and (e) estimates of capital or start-up costs and costs of operation, maintenance, and purchase of services to provide information.

Dated: May 25, 2012.

Bruce A. Sharp,

Bureau Clearance Officer.

[FR Doc. 2012–13174 Filed 5–30–12; 8:45 am]

BILLING CODE 4810–39–P

DEPARTMENT OF THE TREASURY

Bureau of the Public Debt

Proposed Collection: Comment Request

ACTION: Notice and request for comments.

SUMMARY: The Department of the Treasury, as part of its continuing effort to reduce paperwork and respondent burden, invites the general public and other Federal agencies to take this opportunity to comment on proposed and/or continuing information collections, as required by the Paperwork Reduction Act of 1995, Public Law 104–13 (44 U.S.C. 3506(c)(2)(A). Currently the Bureau of the Public Debt within the Department of the Treasury is soliciting comments concerning the Report/Application for Relief on Account of Loss, Theft, or Destruction of United States Bearer Securities (Organizations).

DATES: Written comments should be received on or before July 30, 2012 to be assured of consideration.

ADDRESSES: Direct all written comments to Bureau of the Public Debt, Bruce A.

Sharp, 200 Third Street A4–A, Parkersburg, WV 26106–1328, or *bruce.sharp@bpd.treas.gov.* The opportunity to make comments online is also available at *www.pracomment.gov.*

FOR FURTHER INFORMATION CONTACT: Requests for additional information or copies should be directed to Bruce A. Sharp, Bureau of the Public Debt, 200 Third Street A4–A, Parkersburg, WV 26106–1328, (304) 480–8150.

SUPPLEMENTARY INFORMATION:

Title: Report/Application for Relief on Account of Loss, Theft, or Destruction of United States Bearer Securities (Organizations).

OMB Number: 1535–0015.

Form Number: PD F 1022.

Abstract: The information is requested to establish ownership and support a request for relief due to the loss, theft, or destruction of United States Bearer Securities.

Current Actions: None.

Type of Review: Extension.

Affected Public: Private Sector.

Estimated Number of Respondents: 100.

Estimated Time per Respondent: 55 minutes.

Estimated Total Annual Burden Hours: 92.

Request For Comments: Comments submitted in response to this notice will be summarized and/or included in the request for OMB approval. All comments will become a matter of public record. Comments are invited on: (a) Whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimate of the burden of the collection of information; (c) ways to enhance the quality, utility, and clarity of the information to be collected; (d) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology; and (e) estimates of capital or start-up costs and costs of operation, maintenance, and purchase of services to provide information.

Dated: May 25, 2012.

Bruce A. Sharp,

Bureau Clearance Officer.

[FR Doc. 2012–13171 Filed 5–30–12; 8:45 am]

BILLING CODE 4810–39–P

DEPARTMENT OF THE TREASURY

Bureau of the Public Debt

Proposed Collection: Comment Request

ACTION: Notice and request for comments.

SUMMARY: The Department of the Treasury, as part of its continuing effort to reduce paperwork and respondent burden, invites the general public and other Federal agencies to take this opportunity to comment on proposed and/or continuing information collections, as required by the Paperwork Reduction Act of 1995, Public Law 104–13 (44 U.S.C. 3506(c)(2)(A)). Currently the Bureau of the Public Debt within the Department of the Treasury is soliciting comments concerning the Report/Application for Relief on Account of Loss, Theft, or Destruction of United States Bearer Securities (Individuals).

DATES: Written comments should be received on or before July 30, 2012 to be assured of consideration.

ADDRESSES: Direct all written comments to Bureau of the Public Debt, Bruce A. Sharp, 200 Third Street A4–A, Parkersburg, WV 26106–1328, or *bruce.sharp@bpd.treas.gov.* The opportunity to make comments online is also available at *www.pracomment.gov.*

FOR FURTHER INFORMATION CONTACT: Requests for additional information or copies should be directed to Bruce A. Sharp, Bureau of the Public Debt, 200 Third Street A4–A, Parkersburg, WV 26106–1328, (304) 480–8150.

SUPPLEMENTARY INFORMATION:

Title: Report/Application For Relief on Account of Loss, Theft, or Destruction of United States Bearer Securities (Individuals).

OMB Number: 1535–0016.

Form Number: PD F 1022–1.

Abstract: The information is requested to establish ownership and support a request for relief due to the loss, theft, or destruction of United States Bearer Securities owned by individuals.

Current Actions: None.

Type of Review: Extension.

Affected Public: Organizations.

Estimated Number of Respondents: 100.

Estimated Time per Respondent: 55 minutes.

Estimated Total Annual Burden Hours: 92.

Request for Comments: Comments submitted in response to this notice will be summarized and/or included in the request for OMB approval. All comments will become a matter of public record. Comments are invited on: (a) Whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimate of the burden of the collection of information; (c) ways to enhance the quality, utility, and clarity of the information to be collected; (d) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology; and (e) estimates of capital or start-up costs and costs of operation, maintenance, and purchase of services to provide information.

Dated: May 25, 2012.

Bruce A. Sharp,

Bureau Clearance Officer.

[FR Doc. 2012–13172 Filed 5–30–12; 8:45 am]

BILLING CODE 4810–39–P

FEDERAL REGISTER

Vol. 77 Thursday,
No. 105 May 31, 2012

Part II

Department of Energy

Federal Energy Regulatory Commission

18 CFR Part 35

Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities; Final Rule

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket No. RM10–23–001; Order No. 1000–A]

Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities

AGENCY: Federal Energy Regulatory Commission, Department of Energy.

ACTION: Order on rehearing and clarification.

SUMMARY: The Federal Energy Regulatory Commission affirms its basic determinations in Order No. 1000, amending the transmission planning and cost allocation requirements established in Order No. 890 to ensure that Commission-jurisdictional services are provided at just and reasonable rates and on a basis that is just and reasonable and not unduly discriminatory or preferential. This order affirms the Order No. 1000 transmission planning reforms that: Require that each public utility transmission provider participate in a regional transmission planning process that produces a regional transmission plan; provide that local and regional transmission planning processes must provide an opportunity to identify and evaluate transmission needs driven by public policy requirements established by state or federal laws or regulations; improve coordination between neighboring transmission planning regions for new interregional transmission facilities; and remove from Commission-approved tariffs and agreements a federal right of first refusal. This order also affirms the Order No. 1000 requirements that each public utility transmission provider must participate in a regional transmission planning process that has: A regional cost allocation method for the cost of new transmission facilities selected in a regional transmission plan for purposes of cost allocation and an interregional cost allocation method for the cost of new transmission facilities that are located in two neighboring transmission planning regions and are jointly evaluated by the two regions in the interregional transmission coordination process required by this Final Rule. Additionally, this order affirms the Order No. 1000 requirement that each cost allocation method must satisfy six cost allocation principles.

DATES: This order on rehearing and clarification will be effective on July 2, 2012.

FOR FURTHER INFORMATION CONTACT:

John Cohen, Federal Energy Regulatory Commission, Office of the General Counsel, 888 First Street NE., Washington, DC 20426, (202) 502–8705.

Shiv Mani, Federal Energy Regulatory Commission, Office of Energy Policy and Innovation, 888 First Street NE., Washington, DC 20426, (202) 502–8240.

SUPPLEMENTARY INFORMATION:

Before Commissioners: Jon Wellinghoff, Chairman; Philip D. Moeller, John R. Norris, and Cheryl A. LaFleur.

Order No. 1000–A

Order On Rehearing and Clarification

Issued May 17, 2012

Table of Contents

I. Introduction

1. In Order No. 1000, the Commission amended the transmission planning and cost allocation requirements established in Order No. 890 to ensure that Commission-jurisdictional services are provided at just and reasonable rates and on a basis that is just and reasonable and not unduly discriminatory or preferential. Order No. 1000's transmission planning reforms require: (1) Each public utility transmission provider to participate in a regional transmission planning process that produces a regional transmission plan; (2) that local and regional transmission planning processes must provide an opportunity to identify and evaluate transmission needs driven by public policy requirements established by state or federal laws or regulations; (3) improved coordination between neighboring transmission planning regions for new interregional transmission facilities; and (4) the removal from Commission-approved tariffs and agreements of a federal right of first refusal.

2. Order No. 1000 also requires that each public utility transmission provider must participate in a regional transmission planning process that has: (1) A regional cost allocation method for the cost of new transmission facilities selected in a regional transmission plan for purposes of cost allocation and (2) an interregional cost allocation method for the cost of new transmission facilities that are located in two neighboring transmission planning regions and are jointly evaluated by the two regions in the interregional transmission coordination process required by this Final Rule. Order No. 1000 also requires that each cost allocation method must satisfy six cost allocation principles.

3. Taken together, the reforms adopted in Order No. 1000 will ensure that Commission-jurisdictional services are provided at just and reasonable rates and on a basis that is just and reasonable and not unduly discriminatory or preferential. The Commission therefore rejects requests to eliminate, or substantially modify, the various reforms adopted in Order No. 1000; however, we do make a number of clarifications.[1] We address each of the arguments made by petitioners in turn.[2]

[1] No changes are being made to the regulatory text previously adopted, because any reference to Order No. 1000 (as well as to Order Nos. 888 and 890) in the existing regulatory text is meant to include any clarifications or changes made in subsequent orders on rehearing or clarification (e.g., Order Nos. 888–A, 890–A, and the instant Order No. 1000–A, etc.). The Commission has chosen this convention to help promote readability of the regulatory text.

[2] A list of petitioners filing requests for rehearing and/or clarification is provided in Appendix A. An untimely request for rehearing was filed by the New Jersey Board of Public Utilities (New Jersey BPU). Pursuant to section 313(a) of the Federal Power Act (FPA), 16 U.S.C. 8251(a) (2006), an aggrieved party

II. The Need for Reform

A. Final Rule

4. In Order No. 1000, the Commission concluded that it was appropriate to adopt the package of reforms addressing transmission planning and cost allocation set forth in the order, stating that its review of the record, as well as recent studies, indicated that the transmission planning and cost allocation requirements of Order No. 890 [3] were an inadequate foundation for public utility transmission providers to address challenges they currently face or will face in the near future.[4] The Commission found that the record was adequate to support its conclusion that the existing requirements of Order No. 890 are too narrowly focused geographically and fail to provide for adequate analysis of the benefits associated with interregional transmission facilities traversing neighboring transmission planning regions.[5]

5. The Commission found that recent increases in transmission investment in fact support the need to ensure that transmission planning and cost allocation requirements are adequate to support more efficient and cost-effective investment decisions.[6] It noted that this increase appears to be only the beginning of a longer-term period of investment in new transmission facilities, which is being driven, in part, by changes in the generation mix. Specifically, the Commission explained that existing and potential environmental regulation and state renewable portfolio standards are driving significant changes in the mix of resources, resulting in the early retirement of some coal-fired generation, increased reliance on natural gas for electricity generation, and large-scale integration of renewable generation.[7] The Commission stated that these shifts in the generation fleet increase the need for new transmission and that the existing transmission grids were not built to accommodate them.[8] It stated that the increased focus on investment in new transmission projects makes it even more critical to implement the reforms to ensure that the more efficient or cost-effective projects come to fruition. In short, the Commission stated that the record in this proceeding and the cited reports confirm that additional, and potentially significant, investment in new transmission facilities will be required in the future to meet reliability needs and integrate new sources of generation. The Commission concluded that it was, therefore, critical that it act now to address deficiencies to ensure that more efficient or cost-effective investments are made as the industry addresses these challenges.

6. The Commission then stated that it would not wait for systemic problems to undermine transmission planning before action is taken. Rather, the Commission concluded that it must act promptly to establish the rules and processes necessary to allow public utility transmission providers to ensure planning of and investment in the right transmission facilities as the industry moves forward to address the many challenges it faces. The Commission noted that such planning is a complex process that requires consideration of a broad range of factors and an assessment of their significance over a period that can extend decades into the future, and that the development of transmission facilities can involve long lead times and complex problems related to design, siting, permitting, and financing.[9] Given the need to deal with these matters over a long time horizon, the Commission concluded that it is appropriate and prudent to act at this time rather than allowing the problems in transmission planning and cost allocation to continue or to increase.

7. The Commission concluded that its actions are consistent with the D.C. Circuit's opinions in *National Fuel* and *Associated Gas Distributors.*[10] Consistent with *National Fuel,* the Commission found that the problem it seeks to resolve, i.e., the narrow focus of current planning requirements and the shortcomings of current cost allocation practices, represents a significant ''theoretical threat'' that justifies Order No. 1000's requirements and is not one that the Commission can address adequately or efficiently through the adjudication of individual complaints.[11] The Commission explained that the actual experiences cited in the record provide additional support for action but are not necessary to justify the remedy, and that the remedy is justified by the theoretical threat identified therein.[12]

8. The Commission also explained that the facts and findings of *Associated Gas Distributors* are in no way comparable to the matters involved in this proceeding.[13] It disagreed that its reforms will have an impact on the industry that is comparable to the impact at issue in *Associated Gas Distributors.* The Commission pointed out that compliance with Order No. 1000 will involve the adoption and implementation of additional processes and procedures, and that many public utility transmission providers already engage in processes and procedures of this type, even if some public utility transmission providers may need to do more than others to comply.[14]

9. The Commission disagreed with assertions that it relied on unsubstantiated allegations of discriminatory conduct or that the current Order No. 890 processes have not been in place long enough to justify the reforms.[15] It stated that it need not make specific factual findings of discrimination to promulgate a generic rule to ensure just and reasonable rates or eliminate undue discrimination.

10. The Commission disagreed with claims that any concerns with current transmission planning and cost allocation processes are better dealt with on a case-specific basis rather than through a generic rule.[16] The Commission stated that while the concerns it has with existing planning and cost allocation processes may not affect each region of the country equally, it nonetheless remained concerned that the existing processes are inadequate to ensure the development of more efficient and cost-effective transmission. It noted that it is well-established that the choice between rulemaking and case-by-case adjudication lies primarily in the informed discretion of the administrative agency. It also noted that

must file a request for rehearing within thirty days after the issuance of the Commission's order. Because the 30-day rehearing deadline is statutory, it cannot be extended, and New Jersey BPU's request for rehearing must be rejected as untimely. Moreover, the courts have repeatedly recognized that the time period within which a party may file an application for rehearing of a Commission order is statutorily established at 30 days by section 313(a) of the FPA and that the Commission has no discretion to extend that deadline. *See, e.g., City of Campbell* v. *FERC,* 770 F.2d 1180, 1183 (D.C. Cir. 1985); *Boston Gas Co.* v. *FERC,* 575 F.2d 975, 977–79 (1st Cir. 1978).

[3] *Preventing Undue Discrimination and Preference in Transmission Service,* Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g,* Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g,* Order No. 890–B, 123 FERC ¶ 61,299 (2008), *order on reh'g,* Order No. 890–C, 126 FERC ¶ 61,228 (2009), *order on clarification,* Order No. 890–D, 129 FERC ¶ 61,126 (2009).

[4] *Id.* P 42.

[5] *Id.* P 373.

[6] *Id.* P 44.

[7] *Id.* P 45.

[8] *Id.*

[9] *Id.* P 50.

[10] *Id.* P 51 (citing *National Fuel Gas Supply Corp.* v. *FERC,* 468 F.3d 831 (D.C. Cir. 2006) (*National Fuel*); *Associated Gas Distrib.* v. *FERC,* 824 F.2d 981 (D.C. Cir. 1985) (*Associated Gas Distributors*)).

[11] *Id.* P 52.

[12] *Id.* P 53.

[13] *Id.* P 54–55.

[14] *Id.* P 56–57.

[15] *Id.* P 58.

[16] *Id.* P 60.

each transmission planning region has unique characteristics, and Order No. 1000 provided significant flexibility to transmission planning regions to accommodate regional differences.[17]

11. On the specific issue of nonincumbent transmission developers, the Commission found that there was sufficient justification in the record to implement the elimination of federal rights of first refusal contained in Commission-jurisdictional tariffs or agreements. It noted that although it previously accepted in some cases, and rejected in others, a federal right of first refusal, it found its reasoning in the cases rejecting the federal right of first refusal to be more persuasive. In particular, the Commission stated that it rejected a federal right of first refusal based on an expectation that ''[t]he presence of multiple transmission developers would lower costs to customers.'' [18] The Commission explained that it is not in the economic self-interest of incumbent transmission providers to permit new entrants to develop transmission facilities, even if proposals submitted by new entrants would result in a more efficient or cost-effective solution to a region's needs.[19] In addition, the Commission required all public utility transmission providers to adopt a framework that requires, among other things, the development of qualification criteria and protocols for the submission and evaluation of proposed transmission projects.[20]

12. Regarding its cost allocation reforms, the Commission concluded in Order No. 1000 that considering the changes within the industry and the implementation of other reforms in Order No. 1000, the requirements of Order No. 890 were no longer adequate to ensure rates, terms and conditions of jurisdictional service are just and reasonable and not unduly discriminatory or preferential.[21] It found that the challenges associated with allocating the cost of transmission appear to have become more acute as the need for transmission infrastructure has grown.[22] The Commission explained that within RTO or ISO regions, particularly those that encompass several states, the allocation of transmission costs is often contentious and prone to litigation.[23] It also noted that in other regions, few rate structures are currently in place that reflect an analysis of the beneficiaries of a transmission facility and provide for the corresponding cost allocation of the transmission facility's cost.[24] Similarly, the Commission noted that there are few rate structures in place today that provide for the allocation of costs of interregional transmission facilities.[25] Finally, the Commission found that the lack of clear *ex ante* cost allocation methods that identify beneficiaries of proposed regional and interregional transmission facilities may be impairing the ability of public utility transmission providers to implement more efficient or cost-effective transmission solutions identified during the transmission planning process.[26]

B. Requests for Rehearing and Clarification

1. Arguments Regarding Whether the Commission Provided Substantial Evidence for the Transmission Planning and Cost Allocation Reforms

13. While several petitioners seeking rehearing or clarification express general support for Order No. 1000,[27] others argue that the Commission failed to provide adequate justification under FPA section 206 for adopting its reforms.[28] Coalition for Fair Transmission Policy acknowledges that the circumstances against which the Commission must fulfill its statutory responsibilities change with developments in the electric industry, including changes with respect to demands on the transmission grid; however, it argues that Order No. 1000 takes the principle several steps beyond the Commission's existing statutory authority. Coalition for Fair Transmission Policy contends that the Commission makes a number of statements about problems facing the industry that are remarkable in their ambiguity, and the existence of problems does not empower the Commission to address every policy problem that arises from such developments or to commandeer regional transmission planning. Coalition for Fair Transmission Policy asserts that, if this was the case, section 216 of the FPA, which gives the Commission limited authority to site transmission facilities in national interest electric transmission corridors, would not have been necessary.

14. PPL Companies argue that the Commission failed to show that existing rates, terms and conditions are unjust and unreasonable or unduly discriminatory absent Order No. 1000.[29] They also contend that Order No. 1000 not only fails to identify who is being discriminated against and who is discriminating, but never addresses whether discrimination has actually materialized in the three years since the Commission's last major rulemaking in this area. PPL Companies assert that, although the Commission is empowered to act against undue discrimination before it occurs, it must at least identify the discrimination it seeks to remedy.[30] They also maintain that the Commission did not specify which rate it has found to be unjust and unreasonable or what substantial evidence it relies upon to draw that conclusion.

15. Similarly, California ISO asserts that the Commission failed to identify any instance in which an existing rate is unjust, unreasonable, or unduly discriminatory or preferential because it does not include provisions for interregional coordination. Instead, California ISO asserts that the Commission only offers an unsupported hypothesis that planning between or among regions will enhance the Commission's ability to perform its mission.

16. Oklahoma Gas and Electric Company argues that Order No. 1000 provides no evidence that existing tariff provisions that address the construction and ownership of transmission facilities in any way result in unjust and unreasonable rates, or in undue discrimination against any customers. It asserts that the evidence the Commission cited is far weaker than the evidence it relied upon to support its expansion of the Standards of Conduct in Order No. 2004, where the court stated that ''citing no evidence demonstrating that there is in fact an industry problem is not reasoned decision-making.'' [31]

[17] *Id.* P 61.

[18] *Cleco Power LLC,* 101 FERC ¶ 61,008 at P 117 (2002), *order terminating proceedings,* 112 FERC ¶ 61,069 (2005); *see also Carolina Power and Light Co.,* 94 FERC ¶ 61,273 at 62,010, *order on reh'g,* 95 FERC ¶ 61,282 at 61,995 (2001) (finding that a federal right of first refusal would unduly limit the planning authority and present the possibility of discrimination by self-interested transmission owners, potentially reduce reliability, and possibly precluding lower cost or superior transmission facilities or upgrades by third parties from being planned and constructed).

[19] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 256.

[20] *Id.* P 7.

[21] *Id.* P 497.

[22] *Id.* P 498.

[23] *Id.* P 498.

[24] *Id.* P 498.

[25] *Id.* P 498.

[26] *Id.* P 499.

[27] *See, e.g.,* AEP; WIRES; AWEA; and Energy Future Coalition Group.

[28] *See, e.g.,* Large Public Power Council; Alabama PSC; Xcel; Georgia PSC; Ad Hoc Coalition of Southeastern Utilities; and PPL Companies.

[29] PPL Companies at 6 (citing 16 U.S.C. 825l(b)).

[30] PPL Companies at 6 (citing *Associated Gas Distributors,* 824 F.2d 981 at 1008).

[31] Oklahoma Gas and Electric Company at 14 (citing *National Fuel,* 468 F.3d at 844).

17. Oklahoma Gas and Electric Company also claims that Order No. 1000 is devoid of support for the conclusion that existing tariff provisions interfere with transmission planning. It argues that there is no evidence, anecdotal or otherwise, that current RTO transmission planning processes generate an unreasonably limited range of options, and that there is no evidence that projects are delayed because they are being constructed by incumbent transmission owners. Specifically, Oklahoma Gas and Electric Company argues that the Commission cannot support a finding that the current transmission rules in SPP result in rates that are unjust and unreasonable.[32]

18. Georgia PSC argues that the Commission should recognize ongoing transmission processes that utilities are participating in and allow them to work before inserting another process that will strain resources.

19. Ad Hoc Coalition of Southeastern Utilities and Large Public Power Council assert that the Commission misread *National Fuel,* arguing that the court faulted the Commission for failing to support its decision with record evidence, and was non-committal on whether a decision might be supported by theory alone.[33] They state that it is incumbent on an agency to ''examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made.'' [34] They further note that *National Fuel* commented that ''[p]rofessing that an order ameliorates a real industry problem but then citing no evidence demonstrating that there is in fact an industry problem is not reasoned decision-making.'' [35]

20. Several petitioners take issue with the Commission's conclusion that it may act by citing to a ''theoretical threat'' rather than providing concrete evidence that the reforms are necessary.[36] For example, petitioners argue that the Commission failed to set forth substantial evidence, or any evidence, of undue discrimination to support its reforms.[37] Xcel adds that the Commission appears to concede that it lacks actual evidence of undue discrimination. Ad Hoc Coalition of Southeastern Utilities and Large Public Power Council argue that it is reasonable to conclude that the Commission has effectively conceded that there is no evidence justifying Order No. 1000 and that the Commission is relying on theory alone.[38]

21. Ad Hoc Coalition of Southeastern Utilities and Large Public Power Council, as well as North Carolina Agencies, argue that the flaw in the Commission's decision is that both the problem it aims to solve and the solution are theoretical. Ad Hoc Coalition of Southeastern Utilities contends that reasoned decision-making calls for substantially more than a hypothesis that existing planning and cost allocation mechanisms may be suboptimal, and speculation that the mechanisms discussed in the order will result in the development of more efficient transmission. Southern Companies also argue that the Commission's explanation of the need for the transmission planning and cost allocation reforms in Order No. 1000 is built entirely on speculation.[39] Given this, Southern Companies contend that Order No. 1000 fails to represent lawful, reasoned agency decision-making by depending on a speculative theoretical threat to support the required reforms rather than providing the required assessment.[40]

22. Southern Companies and Ad Hoc Coalition of Southeastern Utilities state that Order No. 1000's reliance on an alleged theoretical threat misinterprets precedent that agencies need to prove theories beyond mere hypothesis or conjecture.[41] They argue that courts have historically allowed agencies to support orders by theory alone when the theory itself is well supported and represents a highly developed prediction of what actually happens in the real world. Southern Companies, Ad Hoc Coalition of Southeastern Utilities, and Large Public Power Council cite to *Business Roundtable* v. *SEC,* [42] where the court concluded that the Securities and Exchange Commission (SEC) had not adequately considered the effects of a proposed rule on efficiency, competition and capital formation. They maintain that the case deals with matters that are similar to the present proceeding.

23. With respect to federal rights of first refusal, Sponsoring PJM Transmission Owners state that Order No. 1000's hypothetical discrimination stands in marked contrast to the concrete findings in Order No. 888 justifying the implementation of open transmission access and assert the Commission offers no evidentiary support for its findings. Baltimore Gas & Electric argues that the Commission is taking away a tariff-sanctioned right with nothing more than a ''concern'' that a right of first refusal may be leading towards rates that may become too high. It states that if the Commission believes that the problem is that rates will become too high, it should deal with the problem directly by lowering them, rather than by eliminating rights of first refusal.[43]

24. FirstEnergy Service Company takes issue with the Commission's reliance on *National Fuel* and asserts that a tenuous application of theory cannot support a rulemaking.[44]

[32] Oklahoma Gas & Electric Company also states that SPP's transmission planning process is robust and almost all of the projects are being completed within designated timeframes. It contends that where appropriate, the process permits nonincumbent developers to collaborate with incumbent transmission owners to address system needs. It also asserts that the 90-day time limit for incumbent transmission owners to agree to build a designated project prevents a transmission provider from blocking or delaying the construction of projects and ensures that the process is open and transparent.

[33] Ad Hoc Coalition of Southeastern Utilities at 16 (quoting *National Fuel,* 468 F.3d at 844 (''[W]e express no view here whether a theoretical threat alone would be sufficient to justify an order extending the Standards to non-marketing affiliates.'')).

[34] *Id.* at 16 (quoting *Motor Vehicles Mfrs. Ass'n of U.S.* v. *State Farm Mut. Auto Ins. Co.,* 463 U.S. 29, 43 (1983) (*State Farm*)).

[35] Ad Hoc Coalition of Southeastern Utilities at 16 (quoting *National Fuel,* 468 F.3d at 843).

[36] *See, e.g.,* Ad Hoc Coalition of Southeastern Utilities; Large Public Power Council; North Carolina Agencies; and Southern Companies.

[37] *See, e.g.,* FirstEnergy Service Company; PSEG Companies at 25–32 (citing the APA, as well as *National Fuel Gas Supply Corp.* v. *FERC,* 468 F.3d 831, 838 (D.C. Cir. 2006) and *Florida Gas Transmission Co.* v. *FERC,* 604 F.3d 636, 645 (D.C. Cir. 2010)); Xcel; PSEG Companies; Sponsoring PJM Transmission Owners; Baltimore Gas & Electric at 15 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 229); Ad Hoc Coalition of Southeastern Utilities at 55 (quoting in part Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 253); Large Public Power Council; and MISO Transmission Owners Group 2.

[38] Large Public Power Council also claims that the D.C. Circuit has taken judicial notice of the efficiencies derived from vertical integration. According to Large Public Power Council, this means that the court is effectively insisting that the Commission offer evidence that decisions to disaggregate utility operations planning must overcome a presumption that the efficiencies derived from vertical integration are not in the public interest. Large Public Power Council at n.38 (citing *National Fuel,* 468 F.3d at 840 (citing *Tenneco Gas* v. *FERC,* 969 F.2d 1187, 1197 (D.C. Cir. 1992))).

[39] Southern Companies at 89–90 (citing *Algonquin Gas Transmission Co.* v. *FERC,* 948 F.2d 1305 (D.C. Cir. 1991)).

[40] Southern Companies at 91 (citing *State Farm,* 463 U.S. 29, 43 (1983)).

[41] Southern Companies at 14 (citing *National Fuel; Electricity Consumer Resource Council* v. *FERC,* 747 F.2d 1511, 1517 (D.C. Cir. 1984) (*ELCON*)); Ad Hoc Coalition of Southeastern Utilities at 22–23 (citing same).

[42] *Business Roundtable* v. *SEC,* 647 F.3d 1144 (D.C. Cir. 2011).

[43] Baltimore Gas & Electric at 18 (quoting *National Fuel Gas Supply Corp.* v. *FERC,* 468 F.3d 831, 844 (D.C. Cir. 2006)).

[44] FirstEnergy Service Company at 15 (citing *National Fuel Supply Corp.* v. *FERC,* 468 F.3d 831 (D.C. Cir. 2006) (*National Fuel*)).

According to FirstEnergy Service Company, while the court in *National Fuel* acknowledged the possibility of an agency proceeding on theory alone to support a rulemaking, it also cautioned that such reliance required a substantial showing of the need in order to proceed.[45] California ISO makes a similar argument. Both FirstEnergy Service Company and California ISO assert that the Commission has not made any showing similar to that described in *National Fuel* to justify its sole reliance on theory.

25. On the issue of the Commission's nonincumbent transmission developer reforms, Southern Companies assert that they do not have a federal right of first refusal and that there are no restrictions on a nonincumbent developer's ability to pursue transmission projects in the SERTP planning process. Southern Companies argue the Commission has failed to articulate a legal basis for imposing its nonincumbent requirements upon Southern Companies, when it has no right of first refusal. Furthermore, Southern Companies argue that the reason for the lack of nonincumbents in the Southeast is because the incumbent transmission owners have developed a robust transmission grid and are adequately investing in transmission. Southern Companies also assert that there have been no significant merchant transmission projects within their footprint because there is no congestion and generation is not remotely located. Thus, Southern Companies argue that Order No. 1000's generic findings of undue discrimination against nonincumbents are counter to record evidence and that to date no nonincumbents have proposed alternative transmission projects in the SERTP. In addition, Southern Companies state that the Commission does not have the authority to impose nonincumbent-related development rights *sua sponte* generically upon the industry.

26. Petitioners also argue that the Commission failed to identify any established theoretical principles in support of its reforms.[46] Southern Companies maintain that the Commission's reasoning does not meet the scientific standards of a ''good theory,'' which it defines as satisfying two conditions: ''[i]t must accurately describe a large class of observations on the basis of a model that contains only a few arbitrary elements, and it must make definite predictions about the results of future observations.'' [47] Xcel argues that if the Commission intends to rely only on theoretical evidence, it must satisfy the requirements of *National Fuel* by explaining why the individual complaint procedure provided an insufficient remedy.[48] MISO Transmission Owners Group 2 asserts that *National Fuel* did not authorize the Commission to issue a rulemaking solely on the basis of a ''theoretical threat'' but indicated that if the Commission attempted to do so, it would be required to provide a substantial explanation. It argues that the Commission provides no such analysis, but rather summarily indicates that the threat of abuse ''is not one that can be addressed adequately or efficiently through the adjudication of individual complaints.'' [49] MISO Transmission Owners Group 2 contends that a case-by-case analysis would be particularly appropriate in this instance given the dearth of empirical evidence demonstrating harm, compared to the actual examples of nonincumbent transmission developer participation in transmission planning processes in MISO and elsewhere.

27. Other petitioners add that the reforms are unnecessary because there is evidence that transmission expansion has increased significantly over the past several years.[50] Large Public Power Council states that Order No. 1000 does not rely on any finding regarding the need to increase transmission development. Some petitioners also point to existing processes in the Southeast as undercutting the predicate for Order No. 1000.[51] North Carolina Agencies assert that there is error in the Commission's unwillingness to consider the highly developed planning processes in the region as a relevant factor in ascertaining the need for new rules. They also claim that although the anticipated demand for significant interregional transmission projects to transfer large amounts of remotely located renewable energy to fulfill public policy mandates is a major factual predicate for the proposals articulated, this is simply not present in the Southeast due to its resource base. They note that the Southeast already has a robust transmission system, as recognized in DOE's 2009 Transmission Congestion Study. North Carolina Agencies state that utilities in the Southeast remain vertically integrated and provide bundled retail service; the bulk of the resulting transmission cost is included in, and recovered through, state approved bundled retail rates. Thus, they argue that the evidence demonstrates that needed transmission investment is not lacking with respect to the utilities in the Southeast.

28. Southern Companies raise similar arguments with respect to existing regional transmission planning, interregional transmission coordination, and cost allocation processes in the Southeast, claiming that the new planning processes will not be associated with any previously unidentified new load growth, supply or demand side resource, or transmission service request because all of those elements are already addressed in the bottom-up planning processes. Southern Companies further argue that because Order No. 1000 lacks a process to identify new solutions, it will only serve to potentially optimize existing upgrades, which is already occurring due to extensive coordination with neighboring utilities in the Southeast. Ad Hoc Coalition of Southeastern Utilities raise similar arguments, and add that Order No. 1000's concern that some regional transmission planning processes permitted by Order No. 890 are only a forum to confirm simultaneous feasibility does not apply to planning processes in the Southeast.

29. Southern Companies explain that their Order No. 890 Attachment K compliance filing was accepted as of July 2010, and none of the changed circumstances cited in Order No. 1000 has occurred since then. Southern Companies assert that the Commission ignored evidence addressing their existing transmission planning processes and explaining how those processes assure consideration of better regional solutions and support just and reasonable rates. Southern Companies assert that unless detailed facts show existing cost allocation methods are impairing the proposal and consideration of better regional solutions, Order No. 1000 may not lawfully determine they are causing Southern Companies' rates, terms, and conditions for transmission service to be unjust and unreasonable. They also argue that, although the Commission is permitted in certain circumstances to make generic findings in support of its rulemaking, specific findings for specific entities are required when the

[45] FirstEnergy Service Company at 15 (quoting *National Fuel,* 468 F.3d 831 at 844–45).

[46] *See, e.g.,* FirstEnergy Service Company; Xcel; Sponsoring PJM Transmission Owners; PSEG Companies; and Xcel.

[47] Southern Companies at 15 (quoting Stephen Hawking & Leonard Mlodinow, A Briefer History of Time 13–14 (2005)).

[48] Xcel at 13–14 (citing *Nat'l Fuel,* 468 F.3d 831, 834, 844 (D.C. Cir. 2006)).

[49] MISO Transmission Owners Group 2 at 15 (quoting Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 52).

[50] *See, e.g.,* PSEG Companies.

[51] *See, e.g.,* Ad Hoc Coalition of Southeastern Utilities; North Carolina Agencies; and Southern Companies.

actual facts applicable to those entities run counter to generic principles.[52] They add that, on rehearing, the Commission must address substantial evidence that supports the justness and reasonableness of Southern Companies' existing processes in determining whether the reforms of Order No. 1000 should be applied to supplant such processes, or exclude Southern Companies from Order No. 1000's generic findings.

30. Ad Hoc Coalition of Southeastern Utilities add that there are no planning gaps that need to be filled in the Southeast by the Commission's interregional coordination requirements. Ad Hoc Coalition of Southeastern Utilities and Southern Companies assert that the Southeastern utilities already share on an interregional basis data containing all of the information needed to make informed and efficient planning decisions. Ad Hoc Coalition of Southeastern Utilities further argues that the implication that additional interregional coordination will identify whether interregional transmission facilities are more efficient or cost-effective than regional transmission facilities is unfounded, and involves integrated resource planning analysis and 'optimatization' analyses along the seams/interfaces that already occur in the Southeast. Ad Hoc Coalition of Southeastern Utilities concludes that the Commission's holdings regarding its interregional coordination requirements are unfounded and counter to the record evidence.

31. Moreover, Ad Hoc Coalition of Southeastern Utilities and Southern Companies assert that the factual record in this rulemaking demonstrates that the required interregional coordination reforms are likely to do more harm than good. For instance, Ad Hoc Coalition of Southeastern Utilities and Southern Companies state that it is costly to negotiate many coordination agreements and parallel OATT language with many different entities and to prospectively implement multiple bureaucratic requirements.

32. Sacramento Municipal Utility District argues that a generic rule is arbitrary and inappropriate to address a problem that exists, if at all, only in isolated pockets.[53] It also argues that the Commission cannot defend its actions on purely theoretical grounds unless it abandons its unsubstantiated claim that an actual problem exists.[54] Sacramento Municipal Utility District states that to the extent the Commission's rule was adopted to address a theoretical problem, it has failed to meet its burden of establishing that the burdens and costs imposed by the rule are justified by the threat to be addressed.[55] With respect to transmission planning in particular, Sacramento Municipal Utility District contends that the assertion that regional planning taking place under Order No. 890 is insufficient and producing unjust and unreasonable rates is premised on the existence of an actual, not theoretical, problem. It states that there is no evidence to support this assertion, and no evidence that the alleged problem affects more than a few isolated regions of the country. Sacramento Municipal Utility District adds that Order No. 1000 scarcely acknowledges comments documenting the success of various regional planning efforts, but instead refers to generalized statements of concern about potential problems in unidentified regions of the country involving unidentified utilities. It states that this is not the type of evidence upon which a rule purporting to address a national problem can be sustained and this is the same problem that resulted in the remand in *National Fuel*.[56] It argues that the Commission failed to establish that the burdens imposed by Order No. 1000 are justified by the threat addressed,[57] and that Order No. 1000 fails the test of reasoned decision-making, citing the fact that Order No. 1000 failed to take into account whether imposition of its mandatory cost allocation provisions will discourage rather than facilitate regional planning. Alabama PSC likewise contends that the speculative benefits identified in Order No. 1000 are not legally sufficient to justify the rule's burdens and disruptions and, as such, Order No. 1000 is not justified under the Commission's authority under section 206. Alabama PSC encourages the Commission to consider a regional or case-by-case approach if the Commission continues to believe that it should move forward with this initiative.

33. Similarly, Ad Hoc Coalition of Southeastern Utilities contends that Order No. 1000 violates the guidance provided by *National Fuel* regarding what may be permissible by an order solely based upon a theory, arguing that the record demonstrates that there will be little benefit, and possible harm, if the interregional transmission coordination requirements are implemented. Additionally, Ad Hoc Coalition of Southeastern Utilities contend that these reforms would be burdensome to implement, because public utility transmission providers would have to negotiate a number of coordination agreements and parallel OATT language with many different entities and then prospectively implement a number of bureaucratic requirements.[58] Southern Companies agree.

34. NARUC argues that Order No. 1000 does not identify actual concerns or problems or rely on any factual record, but relies entirely on the conclusory statement that planning and cost allocation may be impeding the development of beneficial transmission lines. It also argues that efforts to sort through the ambiguities and comply with Order No. 1000 may stall existing local, regional, and DOE-funded interconnectionwide planning processes, creating uncertainty and requiring limited resources to be reallocated to compliance filings rather than to finalizing plans. NARUC further asserts that Order No. 1000 is premature because the results of the interconnectionwide planning process may eliminate the need for reform or indicate a need for different reforms.

35. Some petitioners also take issue with the Commission's efforts to distinguish Order No. 1000 from *Associated Gas Distributors*.[59] Large Public Power Council argues that the Commission is in error in attempting to minimize the exacting evidentiary standard for generic rulemaking called for in *Associated Gas Distributors* on the ground that the impact of the decision here is not ''comparable.'' [60] It argues that while the Commission states in Order No. 1000 that compliance ''will involve implementation of additional processes and procedures'' and many public utility transmission providers

[52] Southern Companies at 92 (citing *National Fuel,* 468 F. 3d at 839).

[53] Sacramento Municipal Utility District at 4 (citing *Associated Gas Distributors,* 824 F.2d 981 at 1019).

[54] Sacramento Municipal Utility District at 5 (citing *National Fuel,* 468 F.3d at 839).

[55] Sacramento Municipal Utility District at 5 (citing *National Fuel,* 468 F.3d at 844).

[56] Sacramento Municipal Utility District at 32 (citing *Nat'l Fuel Gas Supply Corp.* v. *FERC,* 468 F.3d 831, 844 (D.C. Cir. 2006)).

[57] Sacramento Municipal Utility District at 33 (citing *Nat'l Fuel Gas Supply Corp.* v. *FERC,* 468 F.3d 831, 844 (D.C. Cir. 2006)).

[58] Ad Hoc Coalition of Southeastern Utilities at 66 (quoting *National Fuel,* 468 F.3d at 844 (arguing that the Commission must explain how the ''potential danger * * * unsupported by a record of abuse, justifies such costly prophylactic rules.'')).

[59] *See, e.g.,* Large Public Power Council; Ad Hoc Coalition of Southeastern Utilities; MISO Transmission Owners Group 2; Southern Companies; and Sacramento Municipal Utility District.

[60] Large Public Power Council at 17 (quoting Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 56).

''already engage in processes and procedures of this type,'' the goal of Order No. 1000 is to remedy unjust and unreasonable rates on a national basis by implementing new planning and cost recovery procedures.[61] Large Public Power Council asserts that even if this is not the case, the implications of Order No. 1000 involve cost shifting for the recovery of potentially hundreds of billions of dollars in transmission investment. Ad Hoc Coalition of Southeastern Utilities raises similar concerns, explaining that the attempt to distinguish *Associated Gas Distributors* ''gives short shrift to the Commission's ambitions in promulgating Order No. 1000, which is to implement new planning and cost recovery procedures.'' [62]

36. MISO Transmission Owners Group 2 maintains that, while the Commission argued that *Associated Gas Distributors* states that it need not provide empirical data for every proposition upon which it depends, the Commission has a duty to ''respond meaningfully'' to the objections raised by opponents of its proposal, which it failed to do.[63] Southern Companies argue that the Commission did not squarely address comments asserting that there was no need for an industrywide solution when the problem applies only to a limited portion of the industry.

37. Similarly, California ISO argues that the Commission cannot find support in *Associated Gas Distributors* for acting based on a theoretical threat.[64] In contrast to *Associated Gas Distributors,* California ISO asserts that the Commission is not relying on an economic theory to determine the means for achieving its goal, but rather is attempting to rely on theory to establish the statutory predicate for action.[65] Furthermore, California ISO argues that the Commission's hypothesis that, in a regulated market, the absence of an *ex ante* cost allocation method will cause rates to be unjust or unreasonable is not based on an established economic theory. California ISO asserts that there is no empirical evidence for this hypothesis, and that the Commission has not cited any peer-reviewed or other economic analysis supporting its conclusion. As such, California ISO concludes that such a hypothesis cannot support action under section 206.

38. In addition, California ISO argues that the Commission has not identified any evidence to support a causal connection between a cost allocation methodology and improved cost-effectiveness. California ISO acknowledges two commenters that provided concrete examples that uncertainty about cost allocation was preventing some projects from going forward, but argues that these examples do not support the Commission's finding.

39. MISO Transmission Owners Group 2 asserts that the Commission relies on general suppositions to support its mandate that all rights of first refusal be removed from Commission-jurisdictional tariffs and contracts. For example, it states that Order No. 1000 states that nonincumbent transmission developers seeking to invest in transmission can be discouraged from doing so, but the Commission never identifies a single instance of a nonincumbent transmission developer foregoing an opportunity to invest in a transmission facility because of any existing federal right of first refusal. MISO Transmission Owners Group 2 maintains that the Commission ignored examples it and others gave of nonincumbent transmission developer involvement in regional planning processes, such as the CapX2020 Transmission Capacity Expansion Initiative, in which eleven entities, including MISO Transmission Owners, nonincumbent transmission developers, and transmission dependent utilities are engaged in a collaborative effort to construct nearly 700 miles of new extra-high voltage transmission facilities from the Dakotas to Wisconsin.

40. Similarly, MISO argues that while its existing regional planning processes have resulted in significant transmission expansion in the past and will result in even greater transmission construction in the future, Order No. 1000 does not identify any evidence that transmission planning, expansion and/or cost allocation have been hindered or harmed by the Transmission Owners Agreement provisions relating to the obligation to build, including any associated rights whose nature and effects may resemble rights of first refusal. It asserts that the Commission cannot use any evidence that may involve other RTO, ISOs, or public utilities to draw conclusions about any unjustness and unreasonableness of provisions in MISO's Transmission Owners Agreement, and to require the removal or modification of such provisions.

41. Baltimore Gas & Electric states that the Commission's rationale for eliminating the right of first refusal has no applicability to it and other transmission owner members of PJM since they have all relinquished transmission planning decisions to PJM. According to Baltimore Gas & Electric, it does not matter that transmission owners have an economic incentive to be unduly discriminatory in transmission planning once they have transferred that role to an RTO. Baltimore Gas & Electric asserts that PJM's Order No. 890 compliance filing ensures an open, transparent, and stakeholder-participatory transmission planning process that no transmission owner member has the ability to manipulate for anticompetitive purposes. In any event, Baltimore Gas & Electric states that the opportunity for undue discrimination existed in the abstract when federal right of first refusal rights were initially approved by the Commission, and that nothing has changed to warrant their removal now. Baltimore Gas & Electric adds that there are opportunities for any lawfully sanctioned activity to be misused. Thus, Baltimore Gas & Electric concludes that speculation as to how some bad actors may misuse rights is not a rational basis for eliminating the rights for all actors.

42. Similarly, Sunflower, Mid-Kansas, and Western Farmers dispute Order No. 1000's conclusion that it is not in the economic self-interest of public utility transmission providers, at least in the SPP region, to expand the grid to permit access to competing sources of supply to serve their customers.[66] They note that no state in the SPP region has enacted retail competition and, consequently, those states would not stand for anticompetitive behavior by incumbent transmission owners that would result in higher rates to consumers.[67]

43. Petitioners also disagree with the Commission's conclusion that it can rely on the benefits of competition to support the rule without a ground for a reasonable expectation that competition may have some beneficial impact.[68] These petitioners disagree with the Commission's interpretation of, and

[61] Large Public Power Council at 17–18 (quoting Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at 56).

[62] Ad Hoc Coalition of Southeastern Utilities at 18.

[63] MISO Transmission Owners Group 2 at 13.

[64] California ISO at 16 (citing *Associated Gas,* 824 F.2d 981 at 1008–09).

[65] California ISO at 17 (citing *Associated Gas,* 824 F.2d 981 at 1008–09).

[66] Sunflower, Mid-Kansas, and Western Farmers at 3 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 254).

[67] Sunflower, Mid-Kansas, and Western Farmers argue that this is borne out by activity in SPP of at least two independent transmission developers (ITC Great Plains, LLC and Prairie Wind Transmission, LLC).

[68] *See, e.g.,* PSEG Companies; Ad Hoc Coalition of Southeastern Utilities at 55 (quoting Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 268); and Large Public Power Council.

citation to, *Wisconsin Gas*.[69] Ad Hoc Coalition of Southeastern Utilities and Large Public Power Council argue that *Wisconsin Gas* dealt with the benefits of competition associated with promoting competitive sales of natural gas, which Congress made a national policy. In contrast, they argue that there is no indication that Congress has endorsed promoting competition for the development of transmission infrastructure. Large Public Power Council quotes the language from *Wisconsin Gas* where the court stated that ''unsupported or abstract allegations of benefits that will accrue from increased competition cannot substitute for a conscientious effort to take into account what is known as to past experience and what is reasonably predictable about the future.'' [70] Large Public Power Council asserts that here, the Commission not only lacks any legitimate basis for a presumption that competition in the transmission development business serves the public interest, but fails to amass any evidence for its view.

44. A number of petitioners question the Commission's assertion that adding more transmission developers may lead to the identification of more efficient alternatives.[71] Oklahoma Gas and Electric Company asserts that the Commission has not supported the assumption that competition between potential developers in the process of evaluating and selecting proposed projects will result in more cost-effective transmission service rates. Sponsoring PJM Transmission Owners argue that precedent does not support the Commission's conclusion that the mere invocation of general beneficial impacts of competition suffices to support modifying rates pursuant to section 206. Sponsoring PJM Transmission Owners also assert the real issue is not competition between transmission providers, but rather which entity will be the monopoly owner of a transmission line. Oklahoma Gas and Electric Company states that nothing in Order No. 1000 will result in head-to-head competition between service providers, or between competing lines. It elaborates that the market will not be choosing who constructs new projects, but rather the stakeholder process will be used to make a choice based on uncertain estimates and inputs.

45. Sponsoring PJM Transmission Owners argue the Commission has not explained or demonstrated how competition among transmission developers would reduce the cost of transmission construction and consequently transmission service. For instance, Sponsoring PJM Transmission Owners state that even if a nonincumbent submits a proposal that it projects will have the lowest cost, the Commission has produced no evidence that its actual costs of construction will be lower than the cost the incumbent would incur. Instead, they argue that the incumbent is far more likely to have existing rights of way and more experience with construction and logistical issues that may arise in its area, and thus is better positioned politically to overcome local objections to siting. Baltimore Gas & Electric notes that the Commission has recognized that incumbents have certain advantages, such as a unique knowledge of their own systems and other matters, and that the Commission has stated that such factors can be highlighted in the decisional process leading to project selection. Baltimore Gas & Electric states that it is thus unclear to why the Commission would require that the existing federal right of first refusal provision should be eliminated if the same result can be achieved in the decisional process by taking into account that the incumbent is better placed to construct and own a project.

46. Sponsoring PJM Transmission Owners argue the Commission has not explained how any reduction in construction costs—assuming it could be achieved—would translate into lower rates, after taking into account differing corporate structures, rates of return, and Commission-granted incentives. Ad Hoc Coalition of Southeastern Utilities and Large Public Power Council argue that the efficiencies that the Commission presumes will be associated with its decisions, and that it assumes will overcome added costs and risks, are not a matter that the Commission is entitled to presume. Xcel argues that the Commission's rationale to increase competition does not apply to reliability projects, which have the narrow function of ensuring reliable service to customers.[72]

47. Some petitioners argue that the mixed record does not justify the Commissions ruling.[73] For instance, petitioners argue that the Commission must, as a matter of law, take notice of efficiencies lost and reliability problems created by the Commission's decision.[74] Specifically, Large Public Power Council argues that planning engineers will spend time addressing stakeholder and competitors' concerns in Commission-sponsored planning forums rather than working to meet the needs of their native loads. Additionally, it states that countless hours will be needed to perform studies, reengineer systems, and coordinate third-party construction schedules and priorities. Ameren adds that MISO will have to expend considerable resources to re-assess years of transmission planning work to apply the new rule.

48. Sponsoring PJM Transmission Owners argue the Commission has ignored other potential costs associated with eliminating the right of first refusal, including expensive mitigation plans in the event that a nonincumbent abandons a reliability project. Similarly, Xcel asserts that Commission's statement in P 344 of Order No. 1000 indicates the Commission's belief that certain nonincumbent transmission developers will not be able to complete the projects assigned to them. Xcel adds that other risks will increase from the utility transmission providers' inability to guarantee reliable service, such as litigation arising from outages.

49. Ad Hoc Coalition of Southeastern Utilities asserts that Commission policy has persistently treated transmission as a natural monopoly, and therefore the court's decision in *Wisconsin Gas* should serve as a warning light rather than the license that the Commission assumes it to be. Southern Companies contend that Order No. 1000 assumes that vertical integration is unduly discriminatory because it requires nonincumbents to have a right to propose, own, build and operate integrated network elements. Southern Companies assert that they operate under the traditional regulatory compact, with efficiencies of vertical integration, economy of scale, duty to serve, and adequate return on investment, which ensures necessary transmission is constructed on schedule and is appropriately operated and maintained. Southern Companies state that by not recognizing and rationally explaining this change in precedent, the

[69] *See, e.g.,* PSEG Companies; Ad Hoc Coalition of Southeastern Utilities at 56 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 268, n.243); and Large Public Power Council.

[70] Large Public Power Council at 28 (quoting *Wisconsin Gas,* 770 F.2d 1144 at 1158).

[71] *See, e.g.,* Southern Companies; Sponsoring PJM Transmission Owners at 16, 20 (citing *Williston Basin Interstate Pipeline Co.* v. *FERC,* 358 F.3d 45, 50 (D.C. Cir. 2004)); Ad Hoc Coalition of Southeastern Utilities at 57 (quoting *Washington Gas,* 770 F.2d at 1158).

[72] Xcel at 12–13 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 284–85).

[73] *See, e.g.,* Baltimore Gas & Electric at 16–17 (citing *Central Iowa Power Cooperative* v. *FERC,* 606 F.2d 1156 (D.C. Cir. 1979)).

[74] *See, e.g.,* Ad Hoc Coalition of Southeastern Utilities; Large Public Power Council at 27 (citing *National Fuel* and *Tenneco Gas*).

Commission has acted arbitrarily and capriciously.

C. Commission Determination

50. We deny the requests for rehearing that challenge the Commission's determination that the reforms instituted by Order No. 1000 are needed. As we noted in Order No. 1000, changes are at work in the electric utility industry that have created an additional, and potentially significant, need for new transmission infrastructure. Order No. 1000 cited studies conducted by the North American Electric Reliability Corporation (NERC) and Edison Electric Institute (EEI) that confirmed an increase in transmission development over the last several years, and the Commission cited to an EEI-commissioned Brattle Group study suggesting that approximately $298 billion in new transmission facilities will be required over the period 2010 to 2030.[75] Order No. 1000 explained that these changes are being driven in large part by the changes in the generation mix, and it cited NERC's 2009 Assessment, which stated that existing and potential environmental regulation and state renewable portfolio standards are driving significant changes in the generation mix, resulting in early retirements of coal-fired generation, an increasing reliance on natural gas, and large-scale integration of renewable generation.[76]

51. The Commission concluded in Order No. 1000 that current transmission planning and cost allocation requirements are inadequate to meet these challenges. Current requirements threaten to thwart identification of transmission solutions that are more efficient or cost-effective than would be the case without the reforms contained in Order No. 1000. As a result, the Commission concluded—and we affirm here—that it is necessary and appropriate that we take proactive steps to ensure that this threat does not result in such adverse consequences. The narrow focus of current transmission planning requirements, and the shortcomings of current cost allocation practices, represent a threat that justifies Order No. 1000's requirements, and it is not one that the Commission can address adequately or efficiently through the adjudication of individual complaints.[77] The Commission explained that the actual experiences cited in the record provide additional support for action but are not necessary to justify the remedy, and that the remedy is justified by the theoretical threat identified therein.

52. Order No. 1000 addresses the inadequacy of existing requirements by establishing minimum criteria that the transmission planning process must satisfy, including general principles that cost allocation practices must follow. These criteria are interrelated and were designed as a package to ensure that an effective transmission planning process is in place in each region.[78] Effective transmission planning requires coordination among transmission planning entities; is open and transparent, which is necessary for any process that involves multiple entities with a variety of needs or views regarding this process; considers all transmission needs of all transmission customers; results in an identifiable product reflecting regional determinations; and does not create unnecessary barriers to the consideration of good ideas or the selection of the most advantageous transmission solutions, regardless of whether the developer of a transmission solution is an incumbent transmission developer/provider or a nonincumbent transmission developer. Effective transmission planning should also recognize that there may be even more efficient or cost-effective solutions that are identified through interregional transmission coordination efforts than those solutions identified in a regional transmission planning process. Finally, effective transmission planning is performed with a clear *ex ante* understanding of who will pay for a facility selected in a regional transmission plan for purposes of cost allocation. Without that understanding, the likelihood that selected facilities will be implemented is diminished, undermining the entire purpose of the transmission planning process, namely, the development of efficient and cost-effective transmission solutions.

53. These basic principles encompass all the reforms found in Order No. 1000 and show how the reforms are interrelated to serve a common purpose. If any of the reforms are absent, the effectiveness of transmission planning and cost allocation processes would be undermined. We are not able to identify any argument raised on rehearing that demonstrates that any of these principles are invalid. Instead, the overriding objection raised by the petitioners to the Commission's discussion of the need for the reforms in Order No. 1000 is that the Commission either has not demonstrated the existence of a problem that requires correction through implementation of new requirements, or that it has not shown that the problems it has identified exist in all regions of the country, thus undermining the need for generic rules that apply to all public utility transmission providers. The petitioners that raise these objections maintain that the development of needed transmission facilities is proceeding apace, either nationally or in a specific region, and thus currently there is nothing amiss that requires correction. From this, petitioners conclude that the Commission has not presented substantial evidence of a current problem that shows the need for its reforms.

54. We disagree. As the Commission noted in Order No. 1000, the expansion of the transmission grid is the result of a complex and often contentious process that occurs over a long time horizon.[79] It is capital intensive and subject to numerous regulatory hurdles. It is further complicated by the problem of determining how costs for the expansion will be allocated in instances when multiple entities benefit. Given the fundamental importance of transmission infrastructure, and the many difficulties involved in its development, including the long lead times involved, we continue to believe that a proactive approach is necessary. As discussed in Order No. 1000 and reiterated below, such an approach is fully consistent with the applicable legal requirements.

55. Petitioners' specific arguments that the Commission has not adequately justified the need for the reforms in Order No. 1000 fall under six broad headings: (1) The Commission has failed to demonstrate that any existing rate, term or condition of or for transmission service is unjust and unreasonable or unduly discriminatory or preferential; (2) the Commission supports its need for reform based solely on the existence of a theoretical threat, and it is not clear in *National Fuel* whether such a decision can be supported on this basis alone: (3) the theoretical threat that the Commission uses to justify its reforms in Order No. 1000 amounts to hypothesis and speculation and ignores existing realities, especially in the Southeast; (4) the Commission has not identified a theoretical threat that justifies the removal of federal rights of first refusal from Commission-

[75] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at PP 44–45.

[76] *Id.* P 45.

[77] *Id.* P 52.

[78] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at 42; Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 47.

[79] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 50.

jurisdictional tariffs and agreements and that the Commission has not shown that there is a reasonable expectation that competition in transmission development may have some beneficial impact on rates; (5) the burdens imposed by the Commission's reforms outweigh the benefits; and (6) other issues that do not fall into a general category. We address each of these arguments in turn below.

Whether Is It Necessary That the Commission Demonstrate That Any Existing Rate, Term or Condition of or for Transmission Service Is Unjust and Unreasonable or Unduly Discriminatory or Preferential

56. California ISO, PPL Companies, Southern Companies, and Oklahoma Gas and Electric Company challenge the Commission on the grounds that it has failed to demonstrate that any existing rate, term or condition of or for transmission service is unjust and unreasonable or unduly discriminatory or preferential. However, the Commission is not required to make individual findings concerning the rates of individual public utility transmission providers when proceeding under FPA section 206 by means of a generic rule.[80] When the Commission proceeds by rule it can conclude that ''*any* tariff violating the rule would have such adverse effects * * * as to render it 'unjust and unreasonable' '' within the meaning of section 206 of the FPA.[81]

57. One circumstance that can justify the application of this principle is the existence of a threat that, in the absence of Commission action, would materialize and cause rates to be unjust and unreasonable, or unduly discriminatory or preferential. A threat that has not yet materialized is what the court in *National Fuel* described as a ''theoretical threat.'' The Commission justified the need for the reforms in Order No. 1000 based on such a threat created by the inadequacy of existing transmission planning and cost allocation requirements to meet the anticipated challenges facing the industry, a threat whose existence was illustrated by actual problems that the Commission noted in the order, but that are not necessary to justify its response to the threat.[82]

Whether the Reforms in Order No. 1000 can be Supported on the Basis of a Theoretical Threat Alone

58. A number of petitioners call into question the use of a theoretical threat as the basis for the Commission's reforms.[83] For example, Ad Hoc Coalition of Southeastern Utilities maintains that, based on *National Fuel,* it is not clear whether a decision might be supported by theory alone. We disagree that the court in *National Fuel* was non-committal on this point. The court specifically stated that the Commission could choose ''to rely solely on a theoretical threat.'' [84] While it listed certain matters that the Commission would need to address on remand, it did not comment on the possibility of addressing them successfully, nor did it say anything to suggest that this approach might be defective in principle. FirstEnergy Service Company argues that the list of specific matters that the court listed defines the showing that must be made to rely on a theoretical threat in all cases. However, the court's list of matters to be addressed on remand was simply a reflection of the specific issues it saw in the case at hand, not what was required in all cases. Moreover, when the court stated in *National Fuel* that it expressed ''no view here whether a theoretical threat *alone* would justify an order * * *,'' [85] it was referring to the justification of an order in the matter at hand, not any and every possible proceeding. Additionally, we note that the same court subsequently reconfirmed the legitimacy of reliance on theoretical threats, and it based its conclusion directly on the ruling it made in *National Fuel.*[86]

Whether the Commission's Argument That the Reforms in Order No. 1000 Are Needed Amounts to Hypothesis and Speculation and Ignores Existing Realities, Especially in the Southeast

59. Several petitioners characterize the Commission's approach as based on hypothesis and speculation. For example, Southern Companies claim that the Commission is making ''little more than a guess—a speculative hypothesis,'' [87] and Ad Hoc Coalition of Southeastern Utilities and Alabama PSC also claim that the Commission is acting on mere conjecture. Southern Companies insist that the Commission must provide detailed facts showing that existing cost allocation methods are impairing better regional transmission solutions. NARUC states that the Commission does not identify actual concerns or problems or rely on any factual record and instead proceeds in a conclusory fashion. Some petitioners also maintain that the existing situation in the Southeast undercuts the Commission's position.

60. As an initial matter, we note that, based on our expertise and knowledge of the industry, we do not consider it to be speculation or conjecture to conclude that regional transmission planning is more effective if it results in a transmission plan, is open and transparent, and considers all transmission needs. Nor do we consider it speculation or conjecture to state that barriers to the proposal and evaluation of alternative transmission solutions will inhibit more efficient or cost-effective transmission solutions, or that the implementation of transmission plans will be improved where there is a clear *ex ante* understanding of who will pay for the facilities selected in the regional transmission plan for purposes of cost allocation. As we explain in the following discussion, such propositions are fully consistent with the grounds for action that courts have accepted in the past.

61. To argue that drawing such conclusions amounts to speculation or conjecture also conflicts with the principle articulated above that the Commission is not required to make individual findings under section 206 when formulating generic rules. They also imply that a threat that can justify Commission action in a rulemaking must be actual, i.e., one whose consequences have been realized, not one whose consequences are anticipated or, as the court expressed it in *National Fuel,* a threat that is ''theoretical.''

62. These criticisms thus mischaracterize what the courts mean by proceeding on the basis of a theoretical threat. It means to proceed on the basis of a particular type of fact, ''generic'' facts that constitute the basis for ''generic factual predictions'' that can constitute a rational basis for an agency's decision.[88] The court in *Associated Gas Producers* gave the following as an example of an acceptable generic factual prediction: ''the increased incentive to compete

[80] *Associated Gas Distributors* v. *FERC,* 824 F.2d at 1008.

[81] *Id.* (emphasis in original).

[82] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 53.

[83] *See, e.g.,* Ad Hoc Coalition of Southeastern Utilities; and Large Public Power Council.

[84] *National Fuel,* 468 F.3d at 844.

[85] *Id.* at 844.

[86] *BNSF Railway Co.* v. *Surface Transportation Board,* 526 F.3d 770, 778 (D.C. Cir. 2008) (*BNSF Railway Co.*) (finding that the Surface Transportation Board could adopt a new method to correct excessive railroad rates arising through gaming behavior by the railroads even when there was no evidence of such behavior on their part).

[87] Southern Companies at 16.

[88] *Associated Gas Distributors,* 824 F.2d 981 at1008.

vigorously in the market would eventually lead to lower prices for all consumers.'' [89] The court treated such predictions as based on behavioral assumptions that are not subject to serious dispute. Thus the court stated that ''[a]gencies do not need to conduct experiments in order to rely on the prediction that an unsupported stone will fall; nor need they do so for predictions that competition will normally lead to lower prices.'' [90] Indeed, the court acknowledged that such propositions can be accepted without record evidence when the prediction is viewed ''as at least likely enough to be within the Commission's authority.'' [91]

63. Other courts have recognized that when promulgating rules of general and prospective applicability, agencies can draw ''factual inferences * * * in the formulation of a basically legislative-type judgment, for prospective application only.'' [92] Such judgments are closely bound up to what are sometimes referred to as ''legislative facts,'' i.e., ''facts which help the tribunal determine the content of law and of policy and help the tribunal to exercise its judgment or discretion in determining what course of action to take.'' [93] The District of Columbia Circuit has stated that ''legislative facts are crucial to the prediction of future events and to the evaluation of certain risks, both of which are inherent in administrative policymaking.'' [94] The Supreme Court has ruled that when dealing with matters that are ''primarily of a judgmental or predictive nature * * * complete factual support in the record for [an agency's] judgment or prediction is not possible or required; 'a forecast of the direction in which future public interest lies necessarily involves deductions based on the expert knowledge of the agency.' '' [95] This is precisely what is involved in the Commission's reasoning in Order No. 1000.

64. We disagree with the arguments made by various petitioners that we have ignored evidence that disproves our reasoning. The evidence in question consists of a description of the current state of transmission planning and development in a specific region combined with an expression of satisfaction with the current situation. For example, North Carolina Agencies state that there is no evidence that transmission is lacking in the Southeast and that there is no need in this region for transmission projects that can transfer large amounts of renewable energy. North Carolina Agencies state that the transmission planning processes in the Southeast are already highly developed, and Southern Companies state that in the Southeast all transmission needs have already been planned for.

65. First, the Commission is authorized not simply to make generic findings but also to act on generic factual predictions.[96] To state that the facts in a particular region run counter to the Commission's assessment of the future course of events is to argue either that present circumstances can be expected to persist into the future or that certain basic principles, such as the proposition that transmission developers are more likely to invest if they have a mechanism by which their costs will be allocated, do not apply in the region. We do not find the latter sort of claim to be credible, and the former claim simply overlooks the fact that the present is not a prediction of the future. The Commission is authorized to make rules with prospective effect that will prevent situations that are inconsistent with the FPA from occurring, which means that it is authorized to consider how the future may be different from the present if the rules it proposes are not adopted. We thus also reject Sacramento Municipal Utility Districts' claim that the Commission cannot act unless it shows the existence of an ''actual problem'' in a particular region, a claim that lies at the root of all the arguments that petitioners make on this point. An ''actual problem'' is what one has when a theoretical threat comes to fruition. To insist that the Commission must identify the existence of an actual problem in the present before it can act is thus to deny that a theoretical threat that one reasonably concludes exists can be a basis for action. Such a conclusion is inconsistent with the cases we have cited on this point.[97]

66. In addition, these arguments overlook the fact that in Order No. 1000, the Commission identifies a minimum set of requirements that must be met to ensure that transmission planning processes and cost allocation mechanisms result in Commission-jurisdictional services being provided at rates, terms, and conditions that are just and reasonable and not unduly discriminatory or preferential. Given that the requirements are minimum requirements, it would not be surprising that some current practices in some regions may already satisfy many of them. If that is the case, the public utility transmission providers concerned need only show in their compliance filing how current practices in their regions satisfy the Commission's standards. This does not mean that the reforms are not needed, as all of these requirements are not satisfied in all regions. We thus do not consider Alabama PSC's proposal of a regional or case-by-case approach for applying these reforms to be appropriate or necessary. We also disagree with Southern Companies and others that assert that there is not an issue to be remedied in their respective regions. As we note above, if public utility transmission providers believe that they already satisfy the minimum requirements in Order No. 1000, they may seek to demonstrate this in their compliance filings.

67. The concept of minimum requirements supplies the answer to Southern Companies argument that there is no basis for requiring them to adopt the nonincumbent transmission developer reforms of Order No. 1000 because they do not have a federal right of first refusal and because there are no restrictions on nonincumbent transmission projects in the SERTP planning process. Southern Companies also note that to date no nonincumbents have proposed projects in SERTP. They attribute this to incumbents, who they argue have developed a robust transmission grid and are adequately investing in transmission. However, the purpose of the minimum requirements for nonincumbent transmission developers is to provide objective criteria that can help ensure that the lack of nonincumbent participation will not be attributable to lack of equal treatment or some other reason identified in Order No. 1000 as an impairment to the identification and evaluation of more efficient or cost-effective alternatives. Moreover, if the requirements of Order No. 1000 are in fact already met in SERTP, then Southern Companies need only show in their compliance filing how current practices satisfy the Commission's requirements. Finally, Southern Companies state the Commission has no

[89] *Id.* (citing *Wisconsin Gas,* 770 F2d at 1161).

[90] *Id.* at 1008–9.

[91] *Id.* at 1008.

[92] *United States* v. *Florida East Coast Ry.,* 410 U.S. 224, 246 (1973); *United Air Lines, Inc.* v. *Civil Aeronautics Board,* 766 F.2d 1107, 1119 (7th Cir 1985).

[93] *Association of National Advertisers, Inc.,* v. *FTC,* 627 F.2d 1151, 1161–62 (D.C. Cir. 1979) (*Ass'n of National Advertisers*) (*quoting* 2 K. Davis, Administrative Law Treatise, § 15.03, at 353 (1958)).

[94] *Id.* at 1162.

[95] *FCC* v. *National Citizens Committee for Broadcasting,* 436 U.S. 775, 814 (1978) (quoting *FPC* v. *Transcontinental Gas Pipe Line Corp.,* 365 U.S. 1, 29 (1961)); see also *Ass'n of National Advertisers, Inc.,* 627 F.2d at 1162.

[96] *Associated Gas Distributors,* 824 F.2d at 1008.

[97] *See, e.g., BNSF Railway Co.,* 526 F.3d at 778.

authority to impose nonincumbent development rights, but the Commission is not imposing any such rights in Order No. 1000. It is simply establishing minimum requirements for the treatment of nonincumbent transmission developers in the transmission planning process. These requirements do not confer any rights to develop a facility. They only confer a right to have a proposal considered.

68. Some petitioners confuse agency judgments based on legislative facts, i.e., factual inferences made in light of the policy underlying a statute, with formal academic theories. Southern Companies maintain that the theoretical basis of Order No. 1000 does not constitute good theory by scientific standards.[98] California ISO argues that the Commission's hypothesis that the absence of a regional cost allocation method will cause rates to be unjust or unreasonable is not based on an established economic theory and the Commission cites no peer-reviewed or other economic analysis that supports its conclusion.

69. The courts have specifically rejected such notions. The court in *Associated Gas Distributors* clearly distinguished between generic factual predictions that are commonly made in rulemakings and the practice of economics as an academic discipline.[99] The court criticized the use of another case, *Electricity Consumers Resource Council* v. *FERC,*[100] to invoke economic theory as a basis for decision making in a way that is similar to the way that Southern Companies and Ad Hoc Coalition of Southeastern Utilities invoke economic theory. For example, Southern Companies state that ''FERC has pointed to no * * * established theory (such as marginal pricing at issue in *Electricity Consumers*) upon which it may rely to support the application of Order No. 1000's requirements to the Southeast.'' [101] The court in *Associated Gas Distributors* stated that ''[c]learly nothing in *Electricity Consumer's* reference to 'economic theory' was intended to invalidate agency reliance on generic factual predictions merely because they are typically studied in the field called economics.'' [102]

70. This is the case because the court recognized that there was no reason that an agency must demonstrate the validity of well-established general principles such as ''that competition will normally lead to lower prices.'' [103] Southern Companies and Ad Hoc Coalition of Southeastern Utilities confuse a theoretical threat, a potential threat that has not yet materialized, with a theory used in an academic discipline, an area of activity that is not comparable to the tasks or responsibilities entrusted to a regulatory agency. The type of principles that the Commission has relied upon here are fully commensurate with those that the court in *Associated Gas Distributors* said the Commission could utilize when addressing matters that fall within its area of expertise. For these same reasons, we disagree with the argument of California ISO that the Commission's finding that the absence of a cost allocation method will cause rates to be unjust or unreasonable must be based on an established economic theory and that the Commission must cite a peer-reviewed or other economic analysis that supports its conclusion.

71. Moreover, we note that the substantial evidence standard does not require scientific certitude, a point which serves to dispel the confusion between theoretical threats and scientific theories. It only requires evidence that a ''reasonable mind might accept'' as ''adequate to support a conclusion.'' [104] In the context of rulemakings that involve legislative facts and generic factual predictions, the relevant criterion is whether the agency has provided a reasonable explanation of the problem presented and its solution to it.[105] A reasonable justification of a policy choice is not, and given the nature of the task involved cannot be, a scientific prediction.

72. This point is confirmed by the discussion of theoretical threats in *National Fuel.* While some petitioners argue that this case requires substantial empirical verification of the existence of a theoretical threat,[106] a careful examination of what the courts says shows that this is not correct. The court did not specify any requirements for demonstrating the existence of a theoretical threat other than a showing that the threat is ''plausible.'' [107] A specific theoretical threat that it found met this requirement is stated in its entirety in the following language:

> If a pipeline did not have an affiliated marketer, it would be in its interest to disseminate widely information relevant to operating constraints, capacity, and available receipt points, limited only by the cost of doing so. The affiliate relationship, however, creates an incentive for the pipeline to withhold information that otherwise would be made available to the affiliate's competitors. Withholding this information from non-affiliated shippers reduces their ability to arrange transactions efficiently.[108]

This description of a theoretical threat, which is drawn from an earlier decision cited by the court in *National Fuel,* corresponds precisely to the type of generic factual predictions discussed above that can justify agency action. It focuses on an incentive to withhold information that is created simply by the existence of an affiliate relationship. The court nowhere indicated that the plausibility of this theory depended on additional confirmation in the form of predictive economic models or extensive empirical data.

73. We thus disagree with Southern Companies that our use of words such as ''may'' and ''could'' in describing the anticipated effects of our reforms is evidence that these reforms are based on speculation or guesswork. When making a generic factual prediction, one is not predicting what will occur with certainty in every instance but rather what it is reasonable to conclude will occur with sufficient frequency and to a sufficient degree to conclude that the reforms are needed. Our use of words such as ''may'' and ''could'' in this context must be understood in this sense.

74. California ISO states that the Commission is not relying on economic theory to determine the means for achieving its goal but rather to establish a statutory predicate for action. However, a theoretical threat, which should not be confused with an economic theory, is precisely that, a predicate for agency action. The Commission's task is to assess current circumstances and to form a judgment on the steps necessary to avoid adverse effects on rates that it concludes are likely to arise if the present situation persists. We reject the idea that the only

[98] *See, e.g.,* Southern Companies.

[99] *Associated Gas Distributors,* 824 F.2d at 1008.

[100] 747 F.2d 1511 (D.C. Cir. 1984) (*Electricity Consumers*).

[101] Southern Companies at 16.

[102] *Associated Gas Distributors,* 824 F.2d at 1008; *accord Sacramento Municipal Utility District* v. *FERC,* 616 F.3d 520, 531 (D.C. Cir. 2010) (stating that ''[n]either [*Electricity*] *Consumers* nor any other case law prevents the Commission from making findings based on 'generic factual predictions' derived from economic research and theory.'').

[103] *Associated Gas Distributors,* 824 F.2d at 1009.

[104] *Dickenson* v. *Zurko,* 527 U.S. 150, 155 (1999).

[105] *See Federal Communications Commission* v. *Nat'l Citizens Comm. for Broadcasting,* 436 U.S. 775, 814 (1978) (stating that ''complete factual support in the record for the [agency's] judgment or prediction is not possible or required''); *Industrial Union* v. *Hodgson,* 499 F.2d 467 at 475–476 (1974). *Bradford Nat'l Clearing Corp.* v. *SEC,* 590 F.2d 1085, 1103–04 (D.C. Cir. 1978) (judicial deference to agency increases where agency decision rests primarily on predictions).

[106] *See, e.g.,* Sacramento Municipal Utility District.

[107] *National Fuel,* 468 F.3d at 840.

[108] *Tenneco Gas* v. *FERC,* 969 F.2d 1187, 1197 (1992) (*Tenneco Gas*).

appropriate predicates for our action in this area are current failures that are traceable to inadequate transmission planning and cost allocation. That would mean that the only predicate for action is a fully realized threat, which is contrary both to the clear position taken by the courts, and, given the special problems involved in transmission development, to the public interest.[109]

75. Finally, aside from *National Fuel* and *Associated Gas Distributors,* the only case that petitioners cite on rehearing dealing with evidentiary burdens in a rulemaking is *Business Roundtable* v. *SEC.* In that case, the court vacated a rule issued by the SEC on the grounds that it had not adequately considered the rule's effect upon efficiency, competition, and capital formation. A number of petitioners describe this case as involving matters that are ''remarkably'' or ''strikingly'' similar to the present proceeding.[110] However, *Business Roundtable* dealt with a failure by the SEC to comply with specific provisions of the Exchange Act and the Investment Company Act of 1940 that require it to assess the economic impacts of a new rule. The court described these requirements as being ''unique'' to the SEC.[111] Requirements that apply uniquely to the SEC under statutes that it administers do not address requirements that apply to this Commission under the FPA or its compliance with them. Moreover, the petitioners that rely on *Business Roundtable* point to no requirements in the FPA that are similar to those that applied to the SEC under its statutes and that might show how the case applies to this proceeding. We are, of course, required to consider the burdens that Order No. 1000 creates in relation to the benefits that we expect its requirements to produce.[112] However, we have done that and have concluded that, in light of the substantial investment in new transmission facilities that is generally expected to occur, the potential benefits from improved planning for new transmission facilities outweigh the burdens involved in complying with the requirements of Order No. 1000 to revise existing transmission tariffs and institute additional planning procedures.

Whether the Commission Has Identified a Theoretical Threat That Justifies the Removal of Federal Rights of First Refusal From Commission Jurisdictional Tariffs and Agreements and Has Shown That There Is a Reasonable Expectation That Competition in Transmission Development May Have Some Beneficial Impact on Rates

76. A number of petitioners contend that the Commission has not identified a theoretical threat that justifies the removal of federal rights of first refusal from Commission jurisdictional tariffs and agreements and that the Commission has not shown that there is a reasonable expectation that competition in transmission development may have some beneficial impact on rates. In fact, the record in this proceeding includes the type of evidence that courts have found appropriate in these circumstances. The Federal Trade Commission, one of the two federal agencies responsible for enforcement of the antitrust laws, supported the elimination of federal rights of first refusal as a means for promoting consumer benefit, support that it described as consistent with antitrust policy disfavoring regulatory barriers to entry in all but a limited number of instances.[113] While we possess our own expertise on barriers to entry when dealing specifically with the transmission grid, we note that the court in *Tenneco Gas* attributed considerable weight to analogous remarks by the Department of Justice that supported the identification of a theoretical threat.[114]

77. Large Public Power Council maintains that *Wisconsin Gas* contains strictures regarding agency action premised on the benefits of competition that the Commission has violated. This case requires only ''that there must be 'ground for reasonable expectation that competition may have some beneficial impact.' '' [115] We think that there is a reasonable expectation that removal of a barrier to entry in the area of transmission development will have benefits of the type that competition creates in most industries. When the court in *Wisconsin Gas* stated that ''unsupported or abstract allegations of the benefits that will accrue from increased competition'' [116] do not form an adequate basis for agency action, it did this in response to the Commission's position on a complex rate issue whose effects were difficult to discern. Order No. 1000 does not involve a comparable situation. In fact, the court's full argument was that such allegations ''cannot substitute for 'a conscientious effort to take into account what is known as to past experience and what is reasonably predictable about the future.' '' [117] In fact, we have made just such an effort, and on that basis we find it quite reasonable to expect benefits from removing barriers to transmission development. Moreover, as noted above, this analysis is consistent with that of the Federal Trade Commission.

78. We also see no significance in the fact that *Wisconsin Gas* involved competitive sales of natural gas in accordance with a policy established by Congress. Ad Hoc Committee of Southeastern Utilities and Large Public Power Council state that Congress has voiced no similar policy regarding competition in the development of transmission infrastructure, but it likewise has not objected to it. We thus do not see how this difference between *Wisconsin Gas* and this proceeding is controlling. Barriers to entry in this area can adversely affect rates, and our action to ensure that such barriers in the form of federal rights of first refusal do not adversely affect rates is well within the scope of actions that we are authorized to take under section 206 of the FPA. The fact that Congress expressed a policy regarding competitive sales of natural gas does not affect this conclusion. These points also address the objections by Oklahoma Gas and Electric Company and Sponsoring PJM Transmission Owners that the Commission has not supported the conclusion that competition between potential developers will result in more efficient or cost effective solutions or that this conclusion suffices to support Commission action under section 206.

79. Xcel and MISO Transmission Owners Group 2 argue that the

[109] We reject for the same reasons the contention by Ad Hoc Coalition of Southeastern Utilities and Large Public Power Council that it is somehow significant that the Commission has effectively conceded that there is no evidence justifying Order No. 1000 and it is relying on theory alone. The Commission is acting on the basis of a theoretical threat whose existence has been demonstrated through a reasonable explanation. The identification of this threat is based ''on an assessment of the relevant market conditions'' and involves ''a forecast of the direction in which future public interest lies'' which ''necessarily involves deductions based on the expert knowledge of the agency.'' *Ass'n of National Advertisers,* 627 F.2d at 1162 (internal citations omitted). Such judgments will satisfy evidentiary requirements in rulemakings such as this one. *Id.* at 1161–62.

[110] *See, e.g.,* Southern Companies; Ad Hoc Committee of Southeastern Utilities; and Large Public Power Council.

[111] *Business Roundtable* at 1148.

[112] *See, e.g., National Fuel,* 468 F.3d at 844; *Associated Gas Distributors,* 824 F.2d at 1019.

[113] Federal Trade Commission Comments on Proposed Rule at 2, 7.

[114] *Tenneco Gas,* 969 F.2d at 1202.

[115] *Wisconsin Gas,* 770 F.2d 1144, at 1158 (quoting *FCC* v. *RCA Communications, Inc.,* 346 U.S. 86, 96–7 (1953)).

[116] *Id.* at 1158.

[117] *Id.* (quoting *American Public Gas Association* v. *FPC,* 567 F.2d 1016, 1037 (D.C. Cir. 1977)).

Commission has not explained why problems created by federal rights of first refusal cannot be dealt with through individual complaints. Rights of first refusal create barriers to participation in the transmission development process. To require nonincumbent transmission developers to overcome those barriers solely through individual complaint proceedings, requiring litigation each time they seek to engage in the development process would create expense, delay, and uncertainty that would serve as a further disincentive to participation. That is, they would have to invest in project development and participate in an extensive regional transmission planning process, and if the project is then taken over by an incumbent transmission developer/provider who exercises a federal right of first refusal, they would have to invest still more time and resources in litigation. As long as the federal right of first refusal remains in a Commission-approved tariff or agreement, their chances of succeeding in litigation would be severely diminished. They would likely forego participating in that region in the first place and place their efforts elsewhere. The remedy suggested by Xcel and MISO Transmission Owners Group 2 would thus itself act as a form of barrier to entry.

80. MISO Transmission Owners 2, Xcel, and MISO argue that the Commission has not identified an instance where federal rights of first refusal have led to adverse effects on rates, discrimination against a nonincumbent transmission developer, or failure by a nonincumbent to invest in a transmission facility. While the Commission did receive evidence that nonincumbent transmission developers experience discriminatory treatment,[118] we think the more important point is that the practical effect of a federal right of first refusal is to discourage investment by nonincumbent transmission developers. We do not think it is surprising that there is limited evidence of exclusion of nonincumbent transmission developers in a situation that discourages them from proposing projects in the first place. While Sponsoring PJM Transmission Owners contrast the evidence of specific discrimination provided in Order No. 888 to support open access transmission with the number of specific examples of barriers to participation by nonincumbent transmission developers in this proceeding, they fail to acknowledge that Order No. 888 and Order No. 1000 involve different factual circumstances and bases for Commission action. Order No. 888 dealt with instances of undue discrimination in transmission access involving entities that were already connected to the transmission grid. Order No. 1000, by contrast, deals as much or more with the effect on rates of excluding entities whose ability even to become involved in the transmission planning process is being hindered from the outset.

81. MISO Transmission Owners 2 state that the Commission ignored the example of nonincumbent transmission developer participation in CapX2020, which they maintain shows that existing construction rights are not a disincentive to investment, at least with respect to the Midwest ISO.[119] However, MISO Transmission Owners 2 do not identify any nonincumbent transmission developer that independently proposed a transmission project and was able to develop it despite the existence of a federal right of first refusal, and initially referred only to certain transmission dependent utilities that had been ''renters'' of the transmission system'' [120] but that had chosen to invest in and own a portion of CapX2020.[121] While the Commission supports investment in transmission infrastructure by transmission dependent utilities, the existence of a single joint project like CapX2020 does not demonstrate that nonincumbent transmission developers are treated in a manner that is not unduly discriminatory or preferential.

82. We disagree with Baltimore Gas & Electric that if our concern is the effect of federal rights of first refusal on transmission rates, we should deal with rates directly rather than federal rights of first refusal. Barriers to entry affect markets in various ways. These include their ability to discourage innovation. Federal rules should not prevent consumers from being able to benefit from the full range of advantages that competition can provide, which the preservation of barriers to entry does not allow.

83. We also disagree with Baltimore Gas & Electric that our rationale for eliminating federal rights of first refusal has no applicability to the transmission owner members of PJM because they have relinquished all transmission planning decisions to PJM and thus have no economic incentive to discriminate against nonincumbents. Even if the transmission owner members of PJM have no economic reason to object to development by nonincumbent transmission developers, this does not mean that federal rights of first refusal cannot adversely affect transmission rates. In other words, the Commission's rationale for requiring the elimination of federal rights of first refusal is not based solely on the economic incentives of incumbent transmission developers/providers; it is also based on the belief that expanding the universe of transmission developers offering potential solutions can lead to the identification and evaluation of potential solutions to regional needs that are more efficient or cost-effective.

84. These points apply equally to the argument of Sunflower, Mid-Kansas, and Western Farmers that it is not in the economic self-interest of public utility transmission providers in the SPP region to inhibit projects proposed by nonincumbent transmission developers because no state in the SPP region has enacted retail competition. For example, the fact that no state in the SPP region would stand for anticompetitive behavior by incumbent transmission developers/providers does not ensure that the potentially more efficient or cost-effective solutions offered by nonincumbent transmission developers will be considered. To do that, it is necessary to have a requirement that they be considered without having to adjudicate complaints of anticompetitive behavior that discourage proposals of alternative solutions.

85. We disagree with Xcel that requiring the elimination of a federal right of first refusal for reliability projects constitutes an overly broad remedy. While Xcel may be correct that it is less likely that a nonincumbent transmission developer will propose a competing transmission project that satisfies only a specific reliability need, a nonincumbent transmission developer may decide to propose a transmission project that satisfies several regional needs, including a specific reliability need. In that instance, the Commission is concerned that if an incumbent transmission developer/provider has the ability to assert a federal right of first refusal for a transmission project because it addresses a reliability need, then the nonincumbent transmission developer may be discouraged from proposing the transmission project that satisfies several regional needs. In

[118] *See* LS Power Comments on Proposed Rule at 3.

[119] Midwest Transmission Owners 2 Petition for Rehearing at 12.

[120] Midwest Transmission Owners Reply Comments on Proposed Rule at 14.

[121] Midwest Transmission Owners Comments on the Proposed Rule at 37 and n.89. Midwest Transmission Owners 2 consists of all the entities that compose Midwest Transmission Owners, with the exception of American Transmission Company LLC.

addition, we note that nothing in Order No. 1000 prevents an incumbent transmission developer/provider from choosing to meet a reliability need or service obligation by building new transmission facilities that are located solely within its retail distribution service territory or footprint and that is not submitted for regional cost allocation.[122]

86. Ad Hoc Coalition of Southeastern Utilities asserts that the Commission's longstanding treatment of transmission as a natural monopoly undercuts its support for competition in the development of transmission infrastructure, but we see no contradiction here. In dealing with transmission as a natural monopoly, the Commission has explained that ''[t]he monopoly characteristic exists in part because entry into the transmission market is restricted or difficult. * * * In addition, as unit costs are less for larger lines and networks, transmission facilities still exhibit scale economies.'' [123] The Commission has never found that natural monopoly is antithetical to competition in all respects. Rather it has said ''it is often better for a single owner (or group of owners) to build a single large transmission line rather than for many transmission owners to build smaller parallel lines on a non-coordinated basis.'' [124] This is because ''effective competition among owners of parallel transmission lines is unlikely, and often impossible, with existing practices and technology.'' [125] This, however, does not mean that determining who will be the owner (or group of owners) of a particular line with natural monopoly characteristics cannot be done on a competitive basis or that competition in this connection would not promote benefits that are similar to the benefits that it produces elsewhere in our economy, in terms of improved facilities, enhanced technology, or better transmission solutions generally.

87. This point provides the answer to the Oklahoma Gas and Electric's statement that nothing Order No. 1000 will result in head-to-head competition between transmission service providers and PJM Transmission Owners' statement that the real issue is not competition between transmission service providers but rather which entity will be the monopoly owner of a transmission line. These statements overlook the fact that competitive forces can be harnessed in a number of ways. In this case, the Commission seeks to make it possible for nonincumbent transmission developers to compete in the proposal of more efficient or cost-effective transmission solutions. Oklahoma Gas and Electric Company states that the choice of new transmission projects will not be made in the market but rather in the stakeholder process, but this simply highlights the fact that competitive forces can be harnessed in various ways, including through the offering of competitive alternatives in a stakeholder process. Oklahoma Gas and Electric Company states that choices in the stakeholder process are based on uncertain estimates and inputs, but this is true of the transmission planning process whether or not it allows for competitive proposals.

88. The fact that incumbent transmission developers/providers may have certain advantages, such as rights of way and experience with the area in question, does not affect these conclusions. Incumbent transmission developers/providers may in some situations be well-equipped to prevail in a competitive process, but this is not an argument against competition. One cannot presume that an incumbent transmission developer/provider will always be better placed to construct and own a project and that the transmission planning process therefore will always reach the same result with or without a federal right of first refusal, as Baltimore & Electric Company maintains. The fact that an incumbent transmission developer/provider may possess certain capabilities does not imply that the incumbent transmission developer/provider is more capable than any possible nonincumbent transmission developer in all situations.

89. Nor do the effects of differing corporate structures, rates of return, or the other factors mentioned by Sponsoring PJM Transmission Owners affect our conclusion. These are all matters that can be considered in the transmission planning process, as can the issue of potential other costs and risks that Ad Hoc Coalition of Southeastern Utilities and Large Public Power Council propose may arise. Such matters may be relevant to the identification of more efficient or cost effective solutions. We do not see how they require one to conclude that competition will not promote more efficient or cost-effective solutions.

90. Finally, the nonincumbent reforms of Order No. 1000 are not based on the assumption that vertical integration is unduly discriminatory. Southern Companies argues that vertical integration provides efficiencies and benefits to consumers, and we do not deny that this may be the case in some situations. However, if it is, we would expect that vertically-integrated public utilities will be well positioned to compete in a transmission development process that is open to nonincumbent transmission developers. Southern Companies argument against nonincumbent transmission developer participation confuses the concept of vertical integration with that of monopoly. The existence of vertical integration does not imply that the vertically integrated public utility must be a monopoly. The emergence of competitive generation markets makes it no longer possible to argue that vertically integrated utilities are natural monopolies in all aspects of electric service.[126] In short, vertical integration itself is not unduly discriminatory, but there is no basis for claiming that vertical integration requires the exclusion of nonincumbent transmission developers.

Whether the Burdens Imposed by the Commission's Reforms Outweigh the Benefits

91. Next, we address the question of the burdens imposed by the Commission's reforms. The court made clear in both *National Fuel* and *Associated Gas Distributors* that one metric for assessing whether a rule has been adequately justified is whether the costs the rule imposes are reasonable in

[122] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 262.

[123] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Service by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Notice of Proposed Rulemaking and Supplemental Notice of Proposed Rulemaking,* 60 FR 17662 (April 7, 1995), FERC Stats. & Regs. ¶ 32,514, at 33,070 (1995).

[124] *Id.*

[125] *Id.*

[126] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities,* Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036, at 31,642 (1996) (noting Congressional recognition of ''rising costs and decreasing efficiencies of utility-owned generating facilities'' and also describing the emergence of ''non-traditional power producers * * * [that following the enactment of the Public Utility Regulatory Policies Act of 1978] began to build new capacity to compete in bulk power markets''), *order on reh'g,* Order No. 888–A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048, *order on reh'g,* Order No. 888–B, 81 FERC ¶ 61,248 (1997), *order on reh'g,* Order No. 888–C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group* v. *FERC,* 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York* v. *FERC,* 535 U.S. 1 (2002). *See also, Morgan Stanley Capital Group, Inc.* v. *Public Utility District No. 1 of Snohomish County, Washington,* 554 U.S. 527, 535–36 (2008) (stating that ''[s]ince the 1970's * * * engineering innovations have lowered the cost of generating electricity and transmitting it over long distances, enabling new entrants to challenge the regional generating monopolies of traditional utilities'').

light of the threat identified.[127] The Commission acknowledged in Order No. 1000 that its new requirements would require adoption and implementation of additional processes and procedures, but it noted that in many cases public utility transmission providers already engage in processes and procedures of the type in question.[128] Large Public Power Council argues that the implications of Order No. 1000 in ''creating a mechanism for socializing the cost of new regional transmission developments are dramatic, and involve, by the Commission's own reckoning, cost shifting for the recovery of potentially hundreds of billions of dollars in transmission investment.'' [129] However, Order No. 1000 requires that the costs of facilities selected in a regional transmission plan for purposes of cost allocation be allocated in a way that is roughly commensurate with benefits, i.e, allocated in accordance with the requirements of cost causation. To the extent that Large Public Power Council's use of the term ''socializing'' costs is meant to refer to a method of cost allocation that does not conform with the principle of cost causation, we disagree with that characterization of Order No. 1000's cost allocation requirements. Consequently, we do not see how ensuring that the costs of facilities selected in a regional transmission plan for purposes of cost allocation are allocated to those who receive benefits from the facilities represents ''cost shifting'' or an undue burden. On the contrary, it is a clear benefit because it ensures that rates for those facilities will be just and reasonable and not unduly discriminatory or preferential, and it promotes the identification of more efficient or cost-effective transmission solutions. Moreover, it is a benefit that is achieved at minimal cost, i.e., the cost of adopting and implementing additional procedures, in comparison to the estimated billions of dollars of needed transmission investment that current transmission planning and cost allocation practices have been frustrating,[130] or the estimated $298 billion in investment in new transmission facilities that EEI suggests will be required over the period from 2010 to 2030.[131]

92. We likewise disagree with Ad Hoc Coalition of Southeastern Utilities' and Southern Companies' assertion that the interregional transmission coordination reforms are contrary to *National Fuel* because the burdens of such coordination outweigh any potential benefits. We note that Order No. 1000 provided a sufficient rationale for the need for specific reform of the interregional transmission coordination requirements. Order No. 1000 explained that ''[c]lear and transparent procedures that result in the sharing of information regarding common needs and potential solutions across the seams of neighboring transmission planning regions'' would help identify interregional transmission facilities that could more efficiently or cost-effectively meet the needs of each region.[132] The Commission further found that Order No. 890's transmission planning requirements ''are too narrowly focused geographically'' and do not provide for adequate analysis of the benefits of interregional transmission facilities in neighboring regions.[133] Accordingly, the Commission concluded that the interregional transmission coordination reforms should be adopted now and not delayed.

93. We continue to find that we have adequately justified the interregional transmission coordination requirements and that, in doing so, we have fully satisfied what is required by *National Fuel,* as that standard is discussed herein. We disagree with the contention that such requirements are overly burdensome as compared to the benefits. The interregional transmission coordination requirements are part of what goes into effective transmission planning. These requirements will help public utility transmission providers, in consultation with stakeholders, in one transmission planning region to work proactively with their counterparts in neighboring regions to identify what may be more efficient or cost-effective transmission facilities than the solutions identified in individual regional transmission plans. We do not believe these benefits are outweighed by the burdens involved, i.e., the cost of the adoption and implementation of procedures necessary for interregional transmission coordination, particularly when compared to the significant transmission investment expected in the future. Indeed, it may be the case that there will be little burden at all for the members of the Ad Hoc Coalition of Southeastern Utilities in implementing these requirements, given that they state that there is already an ''optimization'' analysis along the seams and interfaces in the Southeast.[134] Accordingly, we deny rehearing on this issue.

94. We also disagree with Large Public Power Council and Ameren that the transmission planning requirements of Order No. 1000 will place unnecessary burdens on planning engineers by requiring them to focus on matters other than meeting the needs of their native loads or will require a reassessment of prior planning. We see no contradiction between transmission planning for native loads and ensuring that transmission plans are consistent with regional or interregional transmission needs. Indeed, the native loads of individual entities ultimately benefit from improved regional transmission planning and interregional transmission coordination because they benefit from improvements to the transmission grid that extend beyond their own local facilities. We therefore do not think that any additional burden that Order No. 1000 may create for planning engineers outweighs the benefits that we expect Order No. 1000 to provide. In addition, the requirements of Order No. 1000 apply only to new transmission facilities, and we therefore do not see how they require a reassessment of past planning activities.

95. We have not, as Sponsoring PJM Transmission Owners contend, ignored costs associated with elimination of federal rights of first refusal, specially the need for expensive mitigation plans in the event a nonincumbent transmission developer abandons a reliability project. We see no reason to expect that the performance of incumbent and nonincumbent transmission developers/providers will differ, and as a result, the example that Sponsoring PJM Transmission Owners advances is based on conjecture. Moreover, selection criteria for project developers are an appropriate means of providing assurances that all project developers will be in a position to fulfill their commitments.

96. Sacramento Municipal Utility District states that Order No. 1000 does not satisfy the requirements of reasoned decision-making because it fails to take into account whether the cost allocation provisions will discourage rather than facilitate regional transmission planning. As we have noted already, the Commission continues to find that

[127] *National Fuel,* 468 F.3d at 844; *Associated Gas Distributors,* 824 F.2d at 1019.

[128] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 56.

[129] Large Public Power Council at 18.

[130] *See* Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 38 (discussing Brattle Group study contending that a large portion of projects with an estimated total cost of over $180 billion will not be built due to overlaps and deficiencies in transmission planning and cost allocation processes).

[131] *See id.* P 44.

[132] *Id.* P 368.

[133] *Id.* P 369.

[134] Ad Hoc Coalition of Southeastern Utilities at 65.

transmission planning is more successful when it is understood upfront who will be allocated costs for the facilities in a transmission plan. Regional cost allocation methods accomplish this, among other things. The regional participants will decide which facilities in the regional transmission plan will have their costs allocated according to a method that they select, and which facilities will not. It is thus known how much each beneficiary will pay for the first set of facilities when the regional transmission plan is formed, and it is known that the latter set of facilities must be supported by the facility sponsors alone. Sacramento Municipal Utility District appears to take the position that the cost allocation requirements will discourage transmission planning because entities will be forced to pay for facilities from which they receive no benefit. We address and reject this argument elsewhere in this order.[135]

Other Issues

97. A number of petitioners raise objections to our demonstrations of the need for reform that do not fall under any of the general categories set forth above.

98. We are not, as Coalition for Fair Transmission Policy asserts, stepping beyond our statutory authority and seeking to address every policy problem that faces the industry. We have fully explained our statutory authority in Order No. 1000, and we are addressing only matters that can affect transmission rates in a way that could cause them to become unjust and unreasonable, or unduly discriminatory or preferential. We find nothing ambiguous about, for example, our reference to such things as the impacts of renewable portfolio policies, as Coalition for Fair Transmission Policy maintains. These policies affect transmission needs and thus transmission rates, and rather than being ambiguous, our reference to them provides a clear and concrete example of how transmission planning cannot be fully effective if it does not consider all transmission needs.

99. We also reject the characterization of our action in Order No. 1000 by Coalition for Fair Transmission Policy as commandeering regional transmission planning. The transmission planning and cost allocation requirements of Order No. 1000 are focused on the transmission planning process, not any substantive outcomes of this process.[136] Order No. 1000 establishes a set of minimum requirements that regional planning must meet and allows considerable flexibility in the implementation of these requirements. Establishing flexible minimum requirements for a process cannot be equated with commandeering that process.

100. Coalition for Fair Transmission Policy states that the Commission's authority under section 216 of the FPA to site transmission facilities in national interest corridors would not have been necessary if it had authority to address all policy problems and commandeer the transmission process. We do not see how the Commission's limited authority under this section is relevant to Order No. 1000. Since we are acting to address matters that can have an adverse effect on transmission rates and are not taking any control over the transmission planning process itself, we are not taking any actions that fall within the scope of the activities authorized in section 216.

101. In response to NARUC's concern that compliance with Order No. 1000 may stall existing local, regional, and DOE-funded interconnection-wide planning, the Commission stated in Order No. 1000 that the compliance filing deadlines it established are compatible with the interests of those that intend to develop transmission planning processes that take into account the lessons learned through the ARRA-funded transmission planning initiatives.[137] NARUC states that its reason for concern is the need to sort through ambiguities and comply with Order No. 1000. The Commission is committed to engaging in outreach and consultation to assist the compliance process. NARUC also maintains that the ARRA-funded transmission planning initiatives may eliminate the need for the Commission's reforms, but as we noted in Order No. 1000, those initiatives are complementary to, not substitutes for, the reforms in Order No. 1000. For example, they do not specifically provide for regional cost allocation or for ongoing coordination of planning for interregional transmission facilities, which we concluded is necessary to ensure that rates, terms, and conditions of jurisdictional services are just and reasonable and not unduly discriminatory or preferential.[138] NARUC has not challenged this conclusion regarding the ARRA-funded transmission planning initiatives in its petition for rehearing.

III. Transmission Planning

A. Regional Transmission Planning Process

102. Order No. 1000 built on the reforms adopted in Order No. 890 to improve regional transmission planning. First, Order No. 1000 required each public utility transmission provider to participate in a regional transmission planning process that produces a regional transmission plan and complies with existing Order No. 890 transmission planning principles.[139] Second, Order No. 1000 adopted reforms under which transmission needs driven by Public Policy Requirements are considered in local and regional transmission planning processes.[140] The Commission explained that these reforms work together to ensure that public utility transmission providers in every transmission planning region, in consultation with stakeholders, evaluate proposed alternative solutions at the regional level that may resolve the region's needs more efficiently or cost-effectively than solutions identified in the local transmission plans of individual public utility transmission providers.[141] The Commission noted that, as in Order No. 890, the transmission planning requirements in Order No. 1000 do not address or dictate which transmission facilities should be either in the regional transmission plan or actually constructed, and that such decisions are left in the first instance to the judgment of public utility transmission providers, in consultation with stakeholders participating in the regional transmission planning process.[142]

1. Legal Authority for Order No. 1000's Transmission Planning Reforms

a. Final Rule

103. Order No. 1000 concluded that the Commission has the authority under section 206 of the FPA to adopt the transmission planning reforms. The Commission explained that the reforms build on those of Order No. 890, in which the Commission reformed the *pro forma* OATT to, among other things, require each public utility transmission provider to have a coordinated, open

[135] *See* discussion *infra* at section IV.

[136] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 12.

[137] *Id.* P 794.

[138] *Id.* P 371.

[139] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 68.

[140] *Id.* The Commission explained that Public Policy Requirements are those established by state or federal laws or regulations, meaning enacted statutes (i.e., passed by the legislature and signed by the executive) and regulations promulgated by a relevant jurisdiction, whether within a state or at the federal level. *Id.* at P 2.

[141] *Id.*

[142] *Id.* P 68 n.57.

and transparent regional transmission planning process.[143] The Commission concluded that the reforms adopted in Order No. 1000 are necessary to address remaining deficiencies in transmission planning and cost allocation processes so that the transmission grid can better support wholesale power markets and thereby ensure that Commission-jurisdictional transmission services are provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential.[144]

104. Order No. 1000 rejected arguments that FPA section 202(a) [145] precluded the Commission from adopting the transmission planning reforms, explaining that this provision requires that the interconnection and coordination, i.e., coordinated operation (such as power pooling), of facilities be voluntary and the provision does not mention planning.[146] The Commission explained that transmission planning is a process that occurs prior to the interconnection and coordination of transmission facilities. The Commission explained that this is consistent with the *Central Iowa Power Coop.* v. *FERC* decision,[147] because the court in that case was presented with a request that the Commission require an enhanced level of, or tighter, power pooling, which the court found it could not do given ''the expressly voluntary nature of coordination under section 202(a).'' [148] Section 202(a) was therefore relevant to the problem at issue in *Central Iowa* because, unlike Order No. 1000, the operation of the system through power pooling was its central subject matter.[149] The Commission also found that because section 202(a) does not mention transmission planning, it was unnecessary to resort to the legislative history of the provision, which nevertheless discussed ''planned coordination'' of the operation of facilities, not the planning process for the identification of transmission facilities.[150]

105. The Commission also made clear that nothing in Order No. 1000 infringed on those matters traditionally reserved to the states, such as matters relevant to siting, permitting and construction, as the reforms in Order No. 1000 are associated with the processes used to identify and evaluate transmission system needs and potential solutions to those needs.[151] Further, the Commission disagreed with commenters suggesting that the transmission planning reforms in the Proposed Rule, which were similar to those adopted in Order No. 1000, were inconsistent or precluded by, or legally deficient for failing to rely on, FPA section 217(b)(4),[152] because Order No. 1000 supports the development of needed transmission facilities, which ultimately benefits load-serving entities.[153]

106. Next, the Commission concluded that it could require public utility transmission providers to amend their OATTs to provide for the consideration of transmission needs driven by Public Policy Requirements. The Commission explained that such requirements may modify the need for and configuration of prospective transmission facility development and construction, and therefore, the transmission planning process and the resulting transmission plans would be deficient if they do not provide an opportunity to consider transmission needs driven by Public Policy Requirements.[154] The Commission also rejected assertions that the transmission planning reforms were inconsistent with the Administrative Procedure Act, due process requirements, or Commission regulations governing incentive rates.[155] The Commission explained that it satisfied FPA section 206's burden, as its review of the record demonstrated that existing transmission planning processes are unjust and unreasonable or unduly discriminatory or preferential.[156] Finally, the Commission addressed concerns raised by non-jurisdictional entities regarding issues associated with public power participation in the regional transmission planning process.[157]

107. In the section above on Need for Reform, the Commission has already addressed legal arguments surrounding the Commission's determination that there is substantial evidence establishing a need for the package of reforms in Order No. 1000. A number of petitioners, however, also seek rehearing of the Commission's conclusions regarding its legal authority to specifically require Order No. 1000's regional transmission planning and interregional transmission coordination reforms. In general, these arguments, addressed below, concern: (1) The Commission's interpretation of FPA section 202(a); (2) the Commission's statements regarding section 217(b)(4); (3) Order No. 1000's alleged infringement on state regulatory jurisdiction; (4) Order No. 1000's requirement to consider transmission needs driven by Public Policy Requirements; (5) legal issues related to interregional transmission coordination; and (6) other legal issues.

b. Order No. 1000's Interpretation of FPA Section 202(a)

i. Requests for Rehearing and Clarification

108. Several petitioners argue that the Commission erred in concluding that FPA section 202(a) permitted the Commission to require public utility transmission providers to engage in mandatory regional transmission planning and interregional transmission coordination.[158] Generally, these petitioners assert that the Commission erred in interpreting both the language of the statute and the D.C. Circuit's *Central Iowa* decision that addressed the scope of section 202(a).[159] Petitioners also cite to the D.C. Circuit's *Atlantic City* decision for support for their proposition that transmission planning

[143] *Id.* P 99.

[144] *Id.*

[145] Section 202(a) reads, in relevant part, as follows:

For the purpose of assuring an abundant supply of electric energy throughout the United States with the greatest possible economy and with regard to the proper utilization and conservation of natural resources, the Commission is empowered and directed to divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy. * * *

16 U.S.C. 824a(a).

[146] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at PP 100–06.

[147] 606 F.2d 1156 (D.C. Cir. 1979) (*Central Iowa*).

[148] *Id.* at 1168.

[149] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at PP 102–03.

[150] *Id.* PP 104–05.

[151] *Id.* P 107.

[152] Section 217(b)(4) of the FPA specifies that:

The Commission shall exercise the authority of the Commission under this Act in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities, and enables load-serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs.

16 U.S.C. 824q(b)(4).

[153] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 108.

[154] *Id.* PP 109–12.

[155] *Id.* PP 113–15.

[156] *Id.* P 116.

[157] *Id.* P 117.

[158] *See, e.g.,* Ad Hoc Coalition of Southeastern Utilities; California ISO; FirstEnergy Service Company; Large Public Power Council; North Carolina Agencies; PPL Companies; Sacramento Municipal Utility District; Southern Companies; and Xcel.

[159] While most of the arguments regarding section 202(a) are opposed to the Commission's authority over transmission planning as a general matter, some parties raise this argument in the specific context of interregional transmission coordination. All of the rehearing requests regarding section 202(a) are addressed here.

is to be left to the voluntary action of public utilities under section 202(a).[160]

109. Many petitioners contend that Order No. 1000's interpretation of section 202(a) is contrary to the plain meaning of the provision. Ad Hoc Coalition of Southeastern Utilities argues that Order No. 1000 itself recognizes that transmission planning is an aspect of the ''coordination of facilities for * * * transmission'' because Order No. 1000 states that ''coordination of planning on a regional basis will also increase efficiency through the *coordination of transmission upgrades.''* [161] Ad Hoc Coalition of Southeastern Utilities also argues that Order No. 1000 states that its interregional coordination requirements involve ''*coordination* with regard to the identification and evaluation of interregional transmission facilities * * *.'' [162] FirstEnergy Service Company also cites to statements in Order No. 1000 itself, which it argues demonstrates that the Commission recognized that transmission planning is an aspect of coordination.[163]

110. Additionally, Ad Hoc Coalition of Southeastern Utilities disagrees that section 202(a) only applies to interconnection and operation because section 202(a) discusses ''interconnection and coordination'' but does not mention operation. It also argues that interconnection is discussed along with coordination rather than to the exclusion of coordination. Thus, it argues that language regarding the ''coordination of facilities for * * * transmission'' encompasses transmission planning. It also argues that the interconnection of transmission facilities encompasses transmission planning. FirstEnergy Service Company asserts that the natural reading of ''coordination'' is not limited to ''coordinated operation,'' but also includes ''coordinated planning.'' [164] FirstEnergy Service Company notes that, while the Commission points to the fact that section 202(a) does not mention planning in an effort to avoid this natural reading of ''coordination,'' the logic of the Commission's argument would mean that ''coordinated operations'' must also be excluded, because section 202(a) does not explicitly mention ''operations,'' a point echoed by California ISO.

111. Ad Hoc Coalition of Southeastern Utilities argues that good utility practice compels the conclusion that coordination and interconnection closely involve system planning, asserting that for transmission systems to be interconnected and operated in a reliable manner, they must be planned in a coordinated manner to avoid serious reliability consequences. FirstEnergy Service Company states that the Commission cites no authority for the proposition that section 202(a) focuses on power pooling, but asserts that, even if power pools were the focus of section 202(a), the fact that the first power pool was formed to realize the benefits and efficiencies possible by interconnecting to share generating resources involves at least a limited form of coordinated planning.

112. Sacramento Municipal Utility District argues that Congress left the issue of regional planning to the voluntary decision of the entities involved and only once they elect to do so would the Commission have authority to determine whether the terms of their arrangements are just and reasonable and not unduly discriminatory.[165] It also argues that if Congress intended that the Commission should encourage the coordination of transmission operations, there is no logical reason that it did not also intend that it encourage transmission planning, which further means that it did not intend that the Commission could mandate transmission planning. Moreover, PPL Companies assert that in all the revisions Congress made to the FPA in the Energy Policy Act of 2005,[166] it did not mandate regional planning and left section 202(a) in place without changes to that provision's voluntary nature.

113. Petitioners also argue that the Commission misinterpreted *Central Iowa,* asserting that the court in that case understood that coordination included transmission planning.[167] FirstEnergy Service Company states that *Central Iowa* described coordination as including planning and described various degrees and methods of regional coordination.[168] Similarly, North Carolina Agencies note that *Central Iowa* quoted the Commission's own statement that ''coordination is joint planning and operation of bulk power facilities by two or more electric systems for improved reliability and increased efficiency * * *.'' They also argue that *Central Iowa's* statement that the Commission could not have mandated the power pooling agreement means that the Commission could not have mandated the adoption of coordinated transmission planning.[169]

114. Large Public Power Council also asserts that the court in *Central Iowa* found that the Commission's involvement in transmission planning rests on the voluntary cooperation of utilities subject to the statute. Sacramento Municipal Utility District contends that the Commission's assertion that *Central Iowa* meant only to refer to the operation of transmission facilities when it said ''voluntary power pooling'' rather than planning of their construction is not credible, noting that the court explicitly stated that one type of pooling arrangement is designed to achieve certain goals, ''plus the economies of joint planning and construction of generation and transmission facilities.'' Ad Hoc Coalition of Southeastern Utilities points to legislative history cited in *Central Iowa* stating that Congress ''is confident that enlightened self-interest will lead the utilities to cooperate * * * in bringing about the economies which can alone be secured through planned coordination.'' [170] It also states that *Central Iowa* noted that non-generating distribution systems ''could attend MAPP meetings at which long-range plans are discussed'' and it points to *Central Iowa*'s rejection of calls to enlarge the scope of the power pooling agreement because it ''would be inconsistent with Congress' intent to

[160] *Atlantic City Elec. Co.* v. *FERC,* 295 F.3d 1, 12 (D.C. Cir. 2002) (*Atlantic City*).

[161] Ad Hoc Coalition of Southeastern Utilities at 35 (quoting Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 254 (emphasis added)). *See also* PPL Companies.

[162] Ad Hoc Coalition of Southeastern Utilities at 35 (quoting Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 345 n.310 (emphasis added)). PPL Companies also point out that Order No. 890 states that ''the coordination requirements imposed [therein] are intended to address transmission planning issues.'' Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 453.

[163] FirstEnergy Service Company at 9 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (stating that Order No. 1000 ''improves coordination between neighboring transmission planning regions'')). FirstEnergy Service Company further argues that Order No. 1000 elsewhere uses ''coordination'' to refer to coordinated planning between regions.

[164] FirstEnergy Service Company at 9 (quoting *Wolverine Power Co.* v. *FERC,* 963 F.2d 446, 454 (D.C. Cir. 1992); *U.S.* v. *Wells,* 519 U.S. 482, 483 (1997)).

[165] Sacramento Municipal Utility District at 23 (citing *Central Iowa,* 606 F.2d at 1167–68).

[166] Energy Policy Act of 2005, Public Law 109–58, §§ 1261 *et seq.,* 119 Stat. 594 (2005) (EPAct 2005).

[167] *See, e.g.,* FirstEnergy Service Company; North Carolina Agencies; Large Public Power Council; Sacramento Municipal Utility District; Ad Hoc Coalition of Southeastern Utilities; and Southern Companies.

[168] FirstEnergy Service Company at 11 (citing *Central Iowa,* 606 F.2d at 1168, n.36).

[169] North Carolina Agencies at 7–8 (citing *Central Iowa,* 606 F.2d at 1168, n.36).

[170] Ad Hoc Coalition of Southeastern Utilities at 30 (citing *Central Iowa,* 606 F.2d at 1162 (quoting S. Rep. No. 74–62)).

promote planned coordination of electric systems.'' [171]

115. Other petitioners also assert that the legislative history of section 202(a), as well as the Commission's own precedent, undermine Order No. 1000's interpretation of that provision.[172] North Carolina Agencies emphasize that Congress rejected arguments by the Federal Power Commission that it should be empowered to mandate such coordination when it adopted section 202(a)'s requirements. They argue that section 202(b) [173] also reveals that Congress purposefully limited the Commission's authority to require coordination by enabling it only to order the interconnection of facilities and the sale/exchange of electricity. Ad Hoc Coalition of Southeastern Utilities and Southern Companies point out that the solicitor of the Federal Power Commission testified before Congress that the express intent in drafting section 202(a) was to facilitate regional planning. Petitioners also cite to Federal Power Commission policy statements regarding data collection that make statements such as ''[l]ong-range planning is an indispensable element to the accomplishment of the objectives of [s]ection 202(a)'' and that achieving the goals of section 202(a) ''requires coordinated efforts on an industry[-]wide basis, at both the regional and national levels, to enhance reliability and adequacy of service.'' [174]

116. Ad Hoc Coalition of Southeastern Utilities points to the *1970 National Power Survey,* which stated that ''coordination is joint planning and operation of bulk power facilities by two or more electric systems for improved reliability and increased efficiency which would not be attainable if each system acted independently.'' [175] Sacramento Municipal Utility District argues that the notion that section 202(a) does not include transmission planning, or that transmission planning is not considered part of the coordination of electric systems, would surprise those who recall the Federal Power Commission's work with regional reliability councils in the decades following the Northeast blackout of 1965. It also asserts that the Commission's interpretation cannot be squared with the 1993 *Policy Statement Regarding Regional Transmission Groups,* where the Commission recognized it lacked authority to mandate the formation of regional transmission organizations.[176]

117. Some petitioners also cite to the D.C. Circuit's *Atlantic City* decision. FirstEnergy Service Company quotes *Atlantic City*'s conclusion that the Commission's ''expansive reading of its section 203 jurisdiction could not be reconciled with section 202, which has been definitively interpreted to make clear that Congress intended coordination and interconnection arrangements be left to the voluntary action of the utilities.'' [177] Ad Hoc Coalition of Southeastern Utilities claims that *Atlantic City* reinforces that section 202(a) encompasses transmission planning, noting that the court held that section 202(a) applied to an ISO arrangement, which encompassed transmission planning, and therefore its voluntary nature precluded the Commission from requiring transmission owners to make a filing under section 203 before they could leave the ISO.[178] Southern Companies state Order No. 1000 conceded that the interregional coordination required constitutes the ''coordination of facilities * * * for transmission.'' [179] Thus, Southern Companies argue that Order No. 1000, by specifying that public utility transmission providers adopt identical terms and conditions in their respective OATTs, requires the functional equivalent of mandatory coordination agreements despite the court's decision in *Atlantic City* that the Commission cannot require adoption of coordination agreements.[180]

118. Southern Companies also assert that the design of the FPA is one of specifically conferred powers, not broad sweeping authority.[181] They add that regional transmission planning is voluntary under section 202(a) and note the Commission did not invoke its limited authority under section 216. Southern Companies also assert that the Commission's broader plenary authority over interstate transmission facilities set forth in FPA section 201 cannot be construed to allow the Commission to indirectly regulate matters incident to primary state jurisdiction over transmission facility necessity, siting, and construction.[182]

119. In addition, Large Public Power Council disagrees with the Commission's statement in Order No. 1000 that Order No. 890 serves as precedent for the exercise of mandatory authority over transmission planning because jurisdictional and non-jurisdictional utilities voluntarily complied with the Order No. 890 reforms, leaving no opportunity for judicial review. Accordingly, Large Public Power Council argues the question of whether the Commission has acted outside of its authority may always be raised.[183]

120. Finally, Ad Hoc Coalition of Southeastern Utilities asserts that even if section 202(a) does not encompass transmission planning, nothing in the FPA provides the Commission with any authority in this area. It reiterates that section 217(b)(4) is clear that the Commission is charged with facilitating transmission planning to meet native load, and it adds that nothing else in the statute suggests that the Commission has authority over this area.

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[171] Ad Hoc Coalition of Southeastern Utilities at 39 (quoting *Central Iowa,* 660 F.2d at 1165, 1170).

[172] *See, e.g.,* Ad Hoc Coalition of Southeastern Utilities; Large Public Power Council; Sacramento Municipal Utility District; and Southern Companies.

[173] FPA section 202(b) provides, in part:

Whenever the Commission, upon application * * * and after notice * * * and after opportunity for hearing, finds such action necessary or appropriate in the public interest it may by order direct a public utility * * * to establish physical connection of its transmission facilities with the facilities of one or more other persons engaged in the transmission or sale of electric energy, to sell energy to or exchange energy with such persons: *Provided,* That the Commission shall have no authority to compel the enlargement of generating facilities for such purposes, nor to compel such public utility to sell or exchange energy when to do so would impair its ability to render adequate service to its customers.

16 U.S.C. 824a(b).

[174] Ad Hoc Coalition of Southeastern Utilities at 40 (quoting *Reliability and Adequacy of Electric Service—Reporting of Data,* Order No. 838–4, 56 FPC 3547, 3548 (1976); *Reliability and Adequacy of Electric Service—Reporting of Data,* Order No. 383, 41 FPC 846 (1969)); Southern Companies at 39–40; Large Public Power Council at 19–20.

[175] Ad Hoc Coalition of Southeastern Utilities at 37. Ad Hoc Coalition of Southeastern Utilities also states that the Commission's interpretation of *Central Iowa* is at odds with former Commissioner Vicky A. Bailey's statement that ''Congress * * * was motivated by the desire to leave the coordination and joint planning of utility systems to be to the voluntary judgment of individual utilities.'' Ad Hoc Coalition of Southeastern Utilities at 40 (quoting *Regional Transmission Organizations,* Order No. 2000, FERC Stats. & Regs. ¶ 31,089 (Bailey, Comm'r. concurring)).

[176] Sacramento Municipal Utility District at 25 (citing *Policy Statement Regarding Regional Transmission Groups,* FERC Stats. & Regs. ¶ 30,967 at 30,870 & 30,872 (1993) (*RTG Policy Statement*)).

[177] First Energy Companies at 7 (citing *Atlantic City,* 295 F.3d at 12).

[178] Ad Hoc Coalition of Southeastern Utilities at n.117 (citing *Atlantic City,* 295 F.3d at 11–14).

[179] Southern Companies at 85 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 345 n.310; 16 U.S.C. 824a(a)).

[180] Southern Companies at 85 (citing *Atlantic City,* 295 F.3d at 12 (D.C. Cir. 2002)).

[181] Southern Companies at 101 (citing *Otter Tail Power Co.* v. *U.S.,* 410 U.S. 366, 374 (1973) (stating that Part II of the FPA does not involve pervasive regulatory scheme over any or all activities that could have an effect on transmission rates or services)).

[182] Southern Companies at 102 (citing 16 U.S.C. 824(b)).

[183] Large Public Power Council at 21 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 99).

ii. Commission Determination

121. We deny rehearing. The arguments provided in the various requests for rehearing on the Commission's interpretation of FPA section 202(a) do not persuade us that the Commission's interpretation is at odds with existing precedent or that it does not represent a reasonable interpretation of the statute. The arguments raised on rehearing largely repeat or further elaborate upon points that the Commission rejected in Order No. 1000. For ease of reference in the following discussion, we restate here our interpretation of section 202(a).

122. Section 202(a) reads, in relevant part, as follows:

> For the purpose of assuring an abundant supply of electric energy throughout the United States with the greatest possible economy and with regard to the proper utilization and conservation of natural resources, the Commission is empowered and directed to divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy. * * * [184]

123. As the Commission explained in Order No. 1000, section 202(a) requires that the interconnection and coordination, i.e., the coordinated operation, of facilities be voluntary. It neither mentions planning nor implicitly establishes limits on the Commission's jurisdiction with respect to transmission planning. The Commission explained that transmission planning is a process that occurs prior to the interconnection and coordination of transmission facilities. The transmission planning process itself does not create any obligations to interconnect or operate in a certain way. Thus, the Commission found that when establishing transmission planning process requirements, it is in no way mandating or otherwise impinging upon matters that section 202(a) leaves to the voluntary action of public utility transmission providers.[185] As explained below, this point is reinforced by the way that section 202(a) presents the matters that it does address in a specific sequence.

124. First, section 202(a) empowers the Commission to divide the country into regional districts. If the Commission takes that step, the statute then envisions voluntary interconnection of facilities within those districts, after which occurs the voluntary coordination of those facilities, something which can occur only after the facilities are interconnected. This sequence leads to the inference that the ''coordination of facilities'' refers to their operational coordination, the only relevant form of coordination once facilities are interconnected.

125. The planning of new transmission facilities occurs before they can be interconnected, and for this reason any transmission planning relevant to these facilities occurs prior to those matters that the statute mandates be voluntary. The requirements of Order No. 1000 explicitly pertain only to the coordination of transmission planning, not the coordination of operations of generation and transmission facilities. In short, Order No. 1000 deals with the coordination of a process that is separate and distinct from, and that is completed prior to, the coordination of facilities that is the concern in section 202(a). For this reason, the transmission planning requirements of Order No. 1000 fall outside the scope of section 202(a) because they apply to matters that occur prior to any actions that fall within its scope.

126. Our task here is to provide a reasonable interpretation of section 202(a),[186] and we have done that. Our reading of the statute follows the direct flow of the statutory language, and in that way, it conforms with ''the cardinal rule that '[s]tatutory language must be read in context [since] a phrase 'gathers meaning from the words around it.' ' '' [187] It draws the most reasonable inference from the absence of any mention of planning, i.e., that Congress did not intend section 202(a) to apply to the planning of new transmission facilities. It also is consistent with the intent of Congress, which was the promotion of the economic use of resources through power pooling, as we discuss herein.[188]

127. The arguments that have been raised on rehearing against this interpretation of section 202(a) fall into two broad categories. The first involves claims concerning the nature of planning. The argument that petitioners advance is that planning by its nature is inherently inseparable from the interconnection and coordination of facilities mentioned in the statute. These arguments assert that the nature of planning is such that the requirement that it be voluntary either is found directly in the plain meaning of the language of the statute or is clearly implied by that language. The second class of arguments involves the claim that a number of court cases involving section 202(a), in particular *Central Iowa,* demonstrate that the transmission planning requirements of Order No. 1000 violate the statute. Many petitioners also point to Commission orders and studies that they claim support the same conclusion.

128. The first class of arguments can be summarized as follows: planning is necessary to interconnect and coordinate facilities; section 202(a) prohibits the Commission from requiring the interconnection and coordination of facilities; therefore, section 202(a) prohibits the Commission from requiring anything pertaining to new transmission facility planning. For example, Ad Hoc Coalition of Southeastern Utilities argues that transmission planning is an aspect of the coordination of facilities, and therefore, if the interconnection and coordination of transmission facilities must be voluntary, transmission planning alone also must be coordinated voluntarily. A number of other petitioners make similar arguments.[189]

129. While it is true that facilities must be planned before they can be interconnected and coordinated, we find that this fact proves nothing regarding the scope of section 202(a). The fact that many significant undertakings require planning does not mean that the planning process is indistinct and inseparable from the implementation of plans and subsequent operations. For instance, there is a significant difference between planning a trip and taking it. Likewise, the act of planning the transmission grid and the act of coordinating facilities in their operations are two quite different things. In the case of transmission facilities, planning involves the consideration of various alternatives using economic and engineering analysis, whereas the operation of interconnected facilities involves operational cooperation, such as coordinated dispatch, among other things. We thus disagree with the various petitioners who argue that the ''coordination of facilities * * * for transmission'' necessarily encompasses transmission planning. The latter must be completed before the former can occur. Moreover, planning is an extremely general concept, which means that in practice there are many different types of planning. A plan for

[184] 16 U.S.C. 824(a) (2006).

[185] *See* Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at PP 100–01.

[186] *Chevron U.S.A.* v. *Natural Resources Defense Council,* 467 U.S. 837, 842–45 (1984) (*Chevron*).

[187] *General Dynamics Land Sys., Inc.* v. *Cline,* 540 U.S. 581, 596 (2004). (quoting *Jones* v. *United States,* 527 U.S. 373, 389, (1999) (quoting *Jarecki* v. *G. D. Searle & Co.,* 367 U.S. 303, 307 (1961))).

[188] *See* discussion *infra* at P 0.

[189] *See, e.g.,* PPL Companies; and Southern Companies.

the coordination of facilities for the generation, transmission, and sale of electric energy is an operational plan for facilities already in existence. Such a plan differs from a plan for the development of new transmission facilities, which is all that is at issue under Order No. 1000.

130. In addition, to plan is not to mandate some action that occurs beyond the planning process. Between planning and the implementation of a plan stands a decision to proceed or not to proceed with some or all of the planning proposals. We thus disagree with North Carolina Agencies that the transmission planning process itself creates obligations regarding interconnection or operation.

131. FirstEnergy Service Company states that one must begin with the literal terms of the statute and maintains that when one does, one finds that the natural reading of ''coordination'' includes both coordinated planning and coordinated operation. While we agree with FirstEnergy Service Company on the starting point of statutory interpretation, one cannot stop there. It is a ''fundamental principle of statutory construction (and, indeed, of language itself) that the meaning of a word cannot be determined in isolation, but must be drawn from the context in which it is used.'' [190] Section 202(a) does not use the term ''coordination'' in isolation but rather in the phrase ''coordination of facilities.'' The language found in section 202(a) does not include any terms such as plan or planning or any synonyms for such terms. We disagree that the ''natural reading'' of ''coordination'' in the phrase ''coordination of facilities'' requires one to conclude that the phrase means both ''coordination of facilities'' and ''coordination of planning.''

132. FirstEnergy Service Company defends its ''natural'' reading of the term ''coordination'' in section 202(a) by pointing to the various uses that the Commission has made of the term in Order No. 1000, including statements on how the planning requirements of Order No. 1000 promote coordination among planning regions. Ad Hoc Coalition of Southeastern Utilities and PPL Companies make similar arguments. We reject these arguments because, as used by the Commission in those instances, ''coordination'' simply means ''joint cooperation,'' not coordination as petitioners argue. The word ''coordination,'' like ''planning,'' is extremely general in its scope. Its meaning in one context, such as section 202(a), does not suggest or imply that it has the same meaning in every other context, such as Commission references to the coordination of new transmission planning. As noted above, ''the meaning of a word cannot be determined in isolation, but must be drawn from the context in which it is used.'' [191] In the case of Order No. 1000, the use of the term ''coordination'' in connection with new requirements is restricted to interregional transmission coordination. We see no connection between the coordination between regions and the coordination of facilities referred to in section 202(a).

133. Additionally, Ad Hoc Coalition of Southeastern Utilities overlooks this point when it argues that Order No. 1000 found that its interregional transmission coordination requirements involve ''*coordination* with regard to the identification and evaluation of interregional transmission facilities * * *.'' [192] The quoted language is taken out of context as the footnote in Order No. 1000 from which it is drawn is intended to make clear that the Commission draws a distinction between the interregional transmission coordination it is requiring in Order No. 1000 and the type of coordination at issue in section 202(a). The full footnote is as follows: ''[w]e note that our use of the term 'coordination' with regard to the identification and evaluation of interregional transmission facilities *is distinct from the type of coordination of system operations discussed in connection with section 202(a) of the FPA.*'' [193] FirstEnergy Service Company also claims support for its argument in the statement in Order No. 1000 that its interregional planning reforms would ''improve coordination among public utility transmission planners with respect to the coordination of interregional transmission facilities.'' [194] This argument, however, fails for the same reason. The language from Order No. 1000 cited immediately above makes clear that the Commission distinguished its use of the word ''coordination'' with regard to interregional coordination of new transmission planning in Order No. 1000 from the meaning of the word ''coordination'' in section 202(a).

134. We also disagree with FirstEnergy Service Company that the Commission cites no authority for the proposition that power pools and operational activities were the focus of section 202(a). *Central Iowa* supports the Commission's view.[195] Moreover, the standard that the Commission must satisfy in advancing an interpretation of section 202(a) is that it be a reasonable interpretation.[196] The Commission's interpretation is a reasonable one, given that the provision seeks the promotion of the ''interconnection and coordination of facilities for the generation, transmission, and sale of electric energy,'' i.e., existing resources of public utility systems, for the purpose of promoting ''the greatest possible economy and with regard to the proper utilization and conservation of natural resources.'' [197] Such economizing of resources is the purpose of a power pool. This is precisely the point made in the secondary literature that the court quoted in *Central Iowa,* which reinforces the point that the case supports the Commission's interpretation.[198]

135. Sacramento Municipal Utility District argues that if Congress intended that the Commission should encourage the coordination of transmission operations, there is no logical reason that it did not also intend that the Commission encourage transmission planning, which further means that it did not intend that the Commission could mandate transmission planning. On the contrary, there is no logical basis for this conclusion. Section 202(a) deals with the coordination of facilities, i.e., facilities already in existence, whereas Order No. 1000 deals with the planning of new transmission facilities. While facilities must be planned before they can be built, and built before they can be coordinated, it does not logically follow that encouragement of the coordination of existing facilities entails encouraging the planning of new facilities, which, if built, could be coordinated. There is thus no logical basis for concluding that Congress intended anything at all with regard to planning of new transmission facilities.

136. Similar considerations apply to the argument that the plain meaning of section 202(a) requires one to conclude that joint planning must be voluntary. The basic principle underlying the plain meaning rule is that in interpreting a statute, ''we start—and if it is 'sufficiently clear in its context,' end—

[190] *Deal* v. *United States,* 508 U.S. 129, at 132 (1993).

[191] *Deal* v. *United States,* 508 U.S. at 132.

[192] Ad Hoc Coalition of Southeastern Utilities at 35 (quoting Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 345 n.310 (emphasis added)).

[193] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 345 n.310 (emphasis added).

[194] *Id.* P 345.

[195] *See, e.g., Central Iowa,* 606 F.2d at 1160–62 (stating that the agreement at issue is designed to promote reliable and economical operation of the interconnected electric network in the mid-continent area).

[196] *Chevron U.S.A.* v. *Natural Resources Defense Council,* 467 U.S. 837, 842–45 (1984) (*Chevron*).

[197] 16 U.S.C. 824a(a).

[198] *Central Iowa,* 606 F.2d at n.16.

with the plain language of the statute.'' [199] To end with the plain language of the statute means that:

* * * when words are free from doubt they must be taken as the final expression of the legislative intent, and are not to be added to or subtracted from by considerations drawn from titles or designating names or reports accompanying their introduction, or from any extraneous source. In other words, the language being plain, and not leading to absurd or wholly impracticable consequences, it is the sole evidence of the ultimate legislative intent.[200]

Section 202(a) makes no mention of transmission plans, planning new transmission, or any planning at all. Therefore, the plain meaning rule does not support petitioners' argument. Petitioners' reading of section 202(a) is not a required interpretation of the statute.

137. For instance, Ad Hoc Coalition of Southeastern Utilities argues that the coordination of facilities for transmission encompasses transmission planning. This is an argument based on inference, not plain meaning, and ''[i]nterpreting the intent of Congress from the inferential meaning of its statutes is a far different exercise * * * from looking at the plain meaning of a statute for an express provision. * * *'' [201] To argue that a statute requires a particular result based on an inference, the inference must be a necessary one, not simply one that is possible.[202] That the interpretation proposed by petitioners is not a necessary one is demonstrated by the existence of other, and in our view, more reasonable interpretations such as the one advanced in Order No. 1000. We are required only to present a reasonable interpretation,[203] and we believe that we have done so.

138. Nevertheless, Ad Hoc Coalition of Southeastern Utilities and Southern Companies further maintain that the Federal Power Commission assisted Congress in drafting the FPA with the express intent of facilitating regional planning. They argue that the legislative history of the statute demonstrates this and undercuts the Commission's position that the ''planned coordination'' mentioned in the legislative history refers only to the coordination of facility operations. However, the evidence on which Ad Hoc Coalition of Southeastern Utilities and Southern Companies base their argument—statements made in Congressional hearings by the Federal Power Commission's solicitor and drafting representative, Dozier A. DeVane—does not support their conclusion and is, at best, irrelevant to the point they seek to make.

139. It is important to note that Mr. DeVane was commenting on an early draft of the FPA that differs in fundamental respects from the version that eventually became law. Specifically, the draft in question created an obligation for all public utilities ''to furnish energy to, exchange energy with, and transmit energy for any person upon reasonable request therefore. * * *'' [204] The draft also required public utilities to receive a certificate of public convenience and necessity before constructing or operating new jurisdictional facilities or abandoning facilities other than through retirement in the normal course of business.[205] In short, the draft statute was to require sales and exchanges of energy that are central to pooling operations, and the Commission was to have direct oversight over the development of the transmission grid through the approval of new facilities prior to construction. As Ad Hoc Coalition of Southeastern Utilities and Southern Companies note, Mr. DeVane considered these sections to be among those that were ''absolutely necessary to effectively carry out regional planning.'' [206] Thus, even if Ad Hoc Coalition of Southeastern Utilities and Southern Companies are correct that the Federal Power Commission draft of the FPA expressed an intent to facilitate planning, that intent is not expressed in the statute itself since provisions that the Federal Power Commission representative considered to be essential to the goal were not included in the statute. Moreover, given the fact that the Commission would have had oversight over the transmission development process through the power to issue certificates of public convenience and necessity, we think that Mr. DeVane meant by ''planning'' the planning and promotion of enhanced power pooling under active Commission supervision, something very different from the matters at issue in this proceeding. We thus do not agree with Ad Hoc Coalition of Southeastern Utilities and Southern Companies that the legislative history of the FPA contradicts the Commission's interpretation of section 202(a) of the statute.

140. This brings us to the second class of arguments advanced by petitioners, those that rely on sources such as court cases dealing with section 202(a), as well as Commission orders and reports. Petitioners who advance such arguments on rehearing focus on *Central Iowa.* As the Commission noted in Order No. 1000, *Central Iowa* dealt with a claim that the Commission should have used its authority under section 206 of the FPA to compel greater integration of the utilities within the Mid-Continent Area Power Pool (MAPP) than was specified in the MAPP agreement. Those who took this position in the Commission proceeding at issue in *Central Iowa* sought to have the Commission require MAPP participants ''to construct larger generation units and engage in single system planning with central dispatch.'' [207] The court held that given ''the expressly voluntary nature of coordination under section 202(a),'' the Commission was not authorized to grant that request.[208]

141. The court in *Central Iowa* was thus presented with a request that the Commission require an enhanced level of, or tighter, power pooling. Section 202(a) was relevant to the problem at issue in *Central Iowa* because the operation of the system through power pooling is its central subject matter. Order No. 1000, however, is focused on the process of planning new transmission, which is distinct from any specific system operations. Nothing in Order No. 1000 is tied to the characteristics of any specific form of system operations, and nothing in it requires any changes in the way existing operations are conducted. Order No. 1000 requires compliance with certain general principles within the

[199] *Lutheran Hosp. of Indiana, Inc.* v. *Business Men's Assur. Co.,* 51 F.3d 1308, 1312 (7th Cir. 1995) (quoting *Ernst & Ernst* v. *Hochfelder,* 425 U.S. 185, 201 (1976)).

[200] *Caminetti* v. *United States,* 242 U.S. 470, 490 (1917).

[201] *Breuer* v. *Jim's Concrete of Brevard, Inc.,* 292 F.3d 1308, 1309 (11th Cir. 2002), *aff'd,* 538 U.S. 691 (2003).

[202] *Kirkhuff* v. *Nimmo,* 683 F.2d 544, 549 (D.C. Cir. 1982); *Safarik* v. *Udall,* 304 F.2d 944, 948 (D.C. Cir. 1962); 2B Sutherland Statutory Construction § 55:3 (7th ed.).

[203] *Chevron,* 467 U.S. at 842–45.

[204] Hearing on H.R. 5423 Before the House Interstate & Foreign Commerce Comm. 74th Cong. 32 (1935).

[205] *Id.* The language on certificates of public convenience and necessity is found in section 204(a) of the draft statute, which provided that:

No public utility shall undertake the construction or extension of any facilities subject to the jurisdiction of the Commission, or acquire or operate any such facilities, or extension thereof, or engage in production or transmission by means of any such new or additional facilities or receive energy from any new source, unless and until there shall first have been obtained from the Commission a certificate that the present or future public convenience and necessity require or will require such new construction, or operation or additional supply of electric energy. * * *

[206] Ad Hoc Coalition of Southeastern Utilities at 41 (quoting Hearing on H.R. 5423 Before the House Interstate & Foreign Commerce Comm. 74th Cong. 560 (1935)); Southern Companies at 40 (quoting the same text).

[207] *Central Iowa,* 606 F.2d at 1166.

[208] *Id.* at 1168.

transmission planning process regardless of the nature of the operations to which that process is attached. The court's interpretation of section 202(a) with respect to system operations is therefore not applicable.[209]

142. Many of the arguments that petitioners make based on their reading of *Central Iowa* attempt to demonstrate that regional transmission planning must be voluntary because the court in various ways noted the importance of planning for the interconnection and coordination of facilities. Large Public Power Council maintains that the court in *Central Iowa* believed that planning was an intimate part of the authority addressed in section 202(a) based on the court's reference to a passage in the legislative history discussing ''the economies which alone can be secured through * * * planned coordination.'' [210] Several petitioners also point to the court's use of the definition of ''coordination'' set forth in the Commission's *1970 National Power Survey*. This definition states that ''coordination is joint planning and operation of bulk power facilities by two or more electric systems for improved reliability and increased efficiency which would not be attainable if each system acted independently.'' Large Public Power Council also cites the court's reference to a passage from the *1970 National Power Survey* that states that the ''[r]eduction of installed reserve capacity is made possible by mutual emergency assistance arrangements and associated coordinated transmission planning.'' [211]

143. As explained in Order No. 1000, section 202(a) does not mention ''planning,'' and we have determined that section 202(a) was not intended to address the process of planning new transmission facilities that is the subject of this proceeding. Moreover, the cited legislative history does not refer to the new transmission planning process that is the subject of Order No. 1000. Instead, the legislative history refers to ''planned coordination,'' i.e., to the pooling arrangements and other aspects of system operation that are the underlying focus of section 202(a). It is in this sense that *Central Iowa* must be understood when it refers to engaging ''voluntarily in power planning arrangements.'' The ''planned coordination'' mentioned in the legislative history cited in *Central Iowa* means ''planned coordination'' of the operation of existing facilities, not the planning process for the identification of new transmission facilities. In short, neither *Central Iowa* nor the legislative history cited in that case involves or applies to the planning process for new transmission facilities. Rather, they deal with the coordinated, i.e., shared or pooled, operation of facilities after those facilities are identified and developed. By contrast, Order No. 1000 deals with the process for planning new transmission facilities, a separate and distinct set of activities that occur before new transmission facility construction and before the generation and transmission operational activities that are the subject of section 202(a).[212]

144. Additionally, we note that in referring to ''the economies which alone can be secured through * * * planned coordination,'' the legislative history is referring to the economies that arise through the coordination of facilities in power pool operations. The legislative history states that Part II of the FPA ''seeks to bring about the regional coordination of the operating facilities of the interstate utilities.'' [213] Planned coordination in facility operations generally involves utilizing the lowest cost generation facilities available at any particular time and reducing installed reserve capacity. The new transmission planning required by Order No. 1000 is intended to ensure that transmission planning processes consider and evaluate possible transmission alternatives and produce transmission plans that can meet transmission needs more efficiently and cost-effectively. Nothing in the coordinated new transmission planning process envisioned by Order No. 1000 requires or inevitably leads to the coordinated operation of existing generation and transmission facilities and coordinated sales of electric energy in pooling operations envisioned in the legislative history of section 202(a).

145. Moreover, the fact that the legislative history describes the coordination of facilities that Congress had in mind as ''planned'' does not make the planning requirements in Order No. 1000 part of what was under discussion in the legislative history. As noted above, planning is an extremely general concept. The broad range of activities that involve planning cannot be deemed to be intrinsically related to each other simply by virtue of having a characteristic in common that virtually all business, commercial, and industrial activities share.

146. Additionally, nothing anyone cites to in the *1970 National Power Survey* suggests that its definition of the term ''coordination'' is intended as an interpretation of the term ''coordination'' for purposes of section 202(a). Moreover, if ''coordination'' means, as the *1970 National Power Survey* defines it to mean, ''joint planning *and* operation of bulk power facilities'' (emphasis supplied), then joint planning alone, which is only one element of the definition, is not coordination under this definition. Therefore, Order No. 1000 does not require coordination under this definition because it does not require one of the essential elements of the definition (i.e., it does not require joint operation). We thus see no basis to conclude that the definition of ''coordination'' in the *1970 National Power Survey* or use of the definition by the court in *Central Iowa* demonstrates that the phrase ''coordination of facilities'' in section 202(a) also means ''coordination of planning.''

147. The language from the *1970 National Power Survey* that Large Public Power Council cites also does not demonstrate that planning is necessarily part of the authority addressed in section 202(a). This language simply points out that coordinated transmission planning can play a role in reducing the amount of installed reserve capacity needed. The coordination of plans for new transmission can have many beneficial effects, but the argument that one of these effects brings it within the function addressed in section 202(a) because it is something that the section requires to be voluntary is another example of a failure to distinguish between new transmission planning and the implementation of plans for other purposes. The statement from the *1970 National Power Survey* does not show that planning is an integral part of the authority addressed in section 202(a) because nothing in it shows how the planning requirements of Order No. 1000 have the effect of requiring either the interconnection or the coordination of facilities.

148. Additionally, Sacramento Municipal Utility District argues that the court in *Central Iowa* did not mean to refer only to facility operations when referring to voluntary power pooling because it noted that some forms of pooling are designed to achieve certain goals, plus economies of joint planning and construction of generation and transmission facilities. This fact does not make joint planning by itself, which is the subject of Order No. 1000, a form

[209] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at 103.

[210] Large Public Power Council at 20 (quoting S Rep. No. 74–621 at 49 (1935), as cited by *Central Iowa,* 606 F.2d at 1162).

[211] Large Public Power Council at 21 (quoting 1970 National Power Survey, p. I–17–1, as cited by *Central Iowa,* 606 F. 2d at n.23).

[212] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 105.

[213] S. Rep. No. 621, 74th Cong., 1st Sess. 4 (1935).

of power pooling or demonstrate that something falls within the scope of section 202(a) simply because it is something that some power pools have decided to do.

149. Sacramento Municipal Utility District also cites *Central Iowa* as support for the argument that the Commission's authority is limited to determining whether the terms of any voluntary agreements to plan together are just and reasonable and not unduly discriminatory or preferential. In fact, however, *Central Iowa* does not support Sacramento Municipal Utility District's argument. In that case, the court approved Commission action requiring joint planning where one group of public utilities refused to agree to plan together with another group. Specifically, the MAPP agreement separated MAPP members into different classes based on the size of their systems and allowed members of the class with larger, but not those with smaller, systems to have access to the planning function. Those not admitted objected, and the Commission found the size criterion irrelevant and unduly discriminatory and required the admission of the previously excluded systems.[214]

150. In other words, *Central Iowa* involved a situation where a power pool voluntarily agreed to joint planning and operation, but allowed only some members to participate in planning. The Commission found that it was unduly discriminatory to allow only some members to participate in planning, directed MAPP to allow all members to participate in planning, and the Court affirmed that decision.[215] While Sacramento Municipal Utility District contends *Central Iowa* limits the Commission's ability to create planning requirements to the circumstances there, nothing in the Court's opinion supports this. Rather the opinion shows that the Court focused on and affirmed the Commission on the specific facts before it. Whether the Commission can mandate planning in other circumstances, such as those here, was neither considered by nor ruled on by the Court. For these reasons, we also disagree with North Carolina Agencies that the court's statement in *Central Iowa* that the Commission could not have mandated the adoption of the MAPP agreement means that the Commission could not have mandated coordinated transmission planning. The court specifically approved a Commission mandate of joint planning.

151. We also disagree with Sacramento Municipal Utility District that the Commission's action in the order underlying *Central Iowa* was proper only because the planning provisions of the MAPP agreement were ''the voluntary decision of the entities involved,'' [216] i.e., the voluntary decision of those MAPP members that had agreed to engage in planning with some MAPP members but not with others. Rather, the Commission imposed the requirement in the absence of any substantive agreement to the requirement among the parties affected, because the practices at issue were matters that were subject to the Commission's jurisdiction under sections 205 and 206 of the FPA.[217] That is, the Commission's authority arises from the fact that planning is a practice that affects rates, and the Commission has a duty under sections 205 and 206 of the FPA to ensure that such practices are just and reasonable and not unduly discriminatory or preferential. Indeed, this is the very same authority upon which the Commission relies in adopting the transmission planning reforms in Order No. 1000. This point also supplies our response to Ad Hoc Coalition of Southeastern Utilities' claim that even if section 202(a) does not encompass transmission planning, nothing in the FPA gives the Commission any authority in this area.

152. Regarding Ad Hoc Coalition of Southeastern Utilities' argument that the Commission's interpretation of *Central Iowa* is at odds with former Commissioner Vicky A. Bailey's statement that ''Congress * * * was motivated by the desire to leave the coordination and joint planning of utility systems to be to the voluntary judgment of individual utilities,'' [218] we note that she made this statement in an opinion in which she concurred in part and dissented in part. Neither concurring opinions nor dissenting opinions constitute binding precedent,[219] and Commissioner Bailey's statement thus does not call into question the validity of our actions here.

153. We also find nothing in *Atlantic City* that is relevant to the issue of the Commission's authority to establish transmission planning requirements. In *Atlantic City,* the court held that the Commission could not require a transmission-owing public utility to obtain authorization under section 203 of the FPA before withdrawing from an ISO. The court reasoned that section 203 applies only to situations where a public utility sells, leases, or otherwise disposes of jurisdictional assets, and the transfers of control over such facilities that occurred when a public utility joined or departed from an ISO did not rise to the level of such a transaction. The court also concluded that the Commission's position that approval under section 203 is required could not be reconciled with the requirement of section 202(a) that arrangements for the interconnection and coordination of facilities be voluntary. The court nowhere stated or implied that these voluntary arrangements also covered planning matters. Indeed, the court's main point was that section 202(a) ''does not provide [the Commission] with any substantive powers 'to compel any particular interconnection or technique of coordination.' '' [220] Nothing in Order No. 1000 compels ''any particular interconnection or technique of coordination'' or indeed any interconnection or coordination of facilities at all.

154. Some petitioners maintain that *Atlantic City* demonstrates that the Commission cannot impose planning requirements because the ISO agreement at issue in that case encompassed transmission planning. However, the fact that section 202(a) has applicability to some aspects of an agreement does not mean that it has applicability to all aspects. The claim to the contrary is based on the idea that every kind of transmission planning is inseparable from the interconnection and coordination of facilities, a claim that we reject. In addition, it is clear from the context in which the court raised section 202(a) in *Atlantic City* that it was not making any statements that are relevant to transmission planning.

155. As noted above, the issue before the *Atlantic City* court was whether the transfer of control over jurisdictional facilities that occurred when a public utility entered or left an ISO was a jurisdictional transfer for purposes of section 203 of the FPA. For purposes of section 202(a), such a transfer constitutes a decision either to

[214] *Mid-Continent Area Power Pool Agreement,* Opinion No. 806, 58 F.P.C. 2622, 2631–36 (1977) (*MAPP Agreement Order*).

[215] *Central Iowa,* 606 F.2d at 1170–72.

[216] Sacramento Municipal Utility District at 23.

[217] *Central Iowa* at 1170; *MAPP Agreement Order,* 58 F.P.C. at 2636–37.

[218] Ad Hoc Coalition of Southeastern Utilities at 40 (quoting *Regional Transmission Organizations,* Order No. 2000, FERC Stats. & Regs. ¶ 31,089 (Bailey, Comm'r. concurring in part and dissenting in part)).

[219] *Maryland* v. *Wilson,* 519 U.S. 408, 412–13 (1997) (acknowledging that a concurring opinion does not constitute binding precedent).

[220] *Atlantic City,* 295 F.3d at 12 (quoting *Duke Power Co.* v. *Federal Power Comm'n,* 401 F.2d 930, 943 (D.C. Cir. 1968)).

coordinate facilities through the ISO or to withdraw from such a coordination arrangement, i.e., to turn operational authority over to an ISO or to reclaim that authority from the ISO. Neither joint nor coordinated new transmission planning involves any transfer of control over any facilities, which makes clear that the court in *Atlantic City* was not addressing issues pertinent to transmission planning. We thus disagree with Southern Companies that the transmission planning requirements of Order No. 1000 constitute the functional equivalent of a coordination agreement that the court in *Atlantic City* found must be voluntary.

156. We also disagree with PPL Companies that the lack of a mandate on regional transmission planning in the Energy Policy Act of 2005 and the fact that Congress made no changes to section 202(a) has any significance for Order No. 1000. Section 202(a) does not mention transmission planning. With respect to the Energy Policy Act of 2005, which does not address regional transmission planning, we note that the Supreme Court has observed that ''[t]he search for significance in the silence of Congress is too often the pursuit of a mirage.'' [221]

157. Sacramento Municipal Utility District maintains that the Commission's work with regional reliability councils in the decades following the Northeast blackout of 1965 contradicts its interpretation of section 202(a). To demonstrate this point, Sacramento Municipal Utility District quotes a long passage from a 1993 proposed rule dealing with information to be filed by transmitting utilities providing information on potentially available transmission capacity and known constraints.[222] The passage in question includes a number of statements that point out the importance of planning for the development of coordinated systems. However, this passage does not mention section 202(a) or the Commission's jurisdiction, and nothing in the document from which it is drawn states anything, either explicitly or implicitly, that allows one to conclude that transmission planning either is or is not something that can be subject to Commission requirements.

158. Finally, the same conclusion applies to the Commission policy statements on data collection that petitioners cite. None of these policy statements includes any analysis of the scope of section 202(a). They do mention the importance of planning for achieving the goals of section 202(a), but such statements do not speak to what the Commission can require with respect to planning. Indeed, since they require reporting of information relevant to planning, one can just as easily infer that they pertain to matters where the Commission can establish requirements.

c. Role of FPA Section 217(b)(4)

i. Requests for Rehearing and Clarification

159. Some petitioners contend that the transmission planning reforms in Order No. 1000 ignore or run counter to the requirements of FPA section 217(b)(4).[223] Similarly, several petitioners raise concerns that Order No. 1000's requirement that public utility transmission providers, in consultation with stakeholders, consider transmission needs driven by Public Policy Requirements is prohibited by section 217(b)(4).[224] Finally, some petitioners argue that the Commission erred in not finding that section 217(b)(4) is a Public Policy Requirement for purposes of Order No. 1000.[225]

160. With respect to whether Order No. 1000's transmission planning reforms are inconsistent with section 217(b)(4), PPL Companies argue that Order No. 1000 undermines the intent of section 217 by stating that all planning improvements will assist load-serving entities.

161. Transmission Dependent Utility Systems ask the Commission to clarify that regional and interregional transmission planning processes will abide by section 217(b)(4) by optimizing solutions for transmission to allow long-term firm access to economically-priced long-term energy supplies by all load-serving entities to best satisfy their service obligations. Transmission Dependent Utility Systems therefore seek clarification or rehearing that coordination of reliability and economic planning includes identifying optimal solutions to congestion, to ensure that load-serving entities' reasonable needs are met under FPA section 217(b)(4). They argue that once a transmission customer identifies an interregional transmission need, the interregional coordination process should consider this even if no developer has proposed an interregional solution and the public utility transmission providers themselves have not identified a potential interregional solution.

162. APPA and National Rural Electric Coops argue that Order No. 1000 incorrectly concludes that section 217(b)(4) does not provide a preference to load-serving entities, explaining that in Order No. 681, the Commission stated that section 217(b)(4) provided such a preference.[226] Meanwhile, Coalition for Fair Transmission Policy states that, rather than seeking a preference, entities are requesting a reasonable safeguard against planning process results that breach an unambiguous statutory prescription. It adds that Order No. 1000's dismissal of requests for section 217(b)(4) protection in the regional transmission process is insufficient in light of Congress' directive to enable load-serving entities to fully implement their resource decisions made under state authority.

163. NARUC argues that the planning process should require integrated resource plans or enacted state energy policies to be properly incorporated in the regional and interregional plans. NARUC states that while Order No. 1000 purports to respect integrated resource planning, it denies requests to have the planning process follow the requirement in FPA section 217(b)(4) for bottom-up transmission planning based on the needs of load-serving entities. It contends that this leaves the process open to potential top-down planning that might abrogate state integrated resource plans or other electricity policies enacted by state legislatures or regulators. Finally, NARUC seeks clarification that the Commission does not intend to leverage regional and interregional transmission plans that emerge from Order No. 1000 or the forthcoming compliance processes to infringe upon state siting authority or exceed the Commission's backstop siting authority under FPA section 216.

[221] *Sampson* v. *Murray,* 415 U.S. 61, 78 (1974) (quoting *Scripps-Howard Radio* v. *F.C.C.,* 316 U.S. 4, 11 (1942)).

[222] *New Reporting Requirement Under the Federal Power Act and Changes to Form No. FERC–714,* FERC Stats. & Regs, Proposed Regulations ¶ 32,685 at 32,688 (1993).

[223] *See, e.g.,* PPL Companies; Southern Companies; Ad Hoc Coalition of Southeastern Utilities; and North Carolina Agencies. Ad Hoc Coalition of Southeastern Utilities and Southern Companies argue that Congress added section 217 in response to the Commission's Standard Market Design (SMD) proposal in Docket No. RM01–12–000. They assert that many considered this proposal as an intrusion on utilities' ability plan to meet their native load.

[224] *See, e.g.,* Large Public Power Council; Southern Companies; Ad Hoc Coalition of Southeastern Utilities.

[225] *See,* e.*g.,* Ad Hoc Coalition of Southeastern Utilities; APPA; Large Public Power Council; National Rural Electric Coops; and Transmission Access Policy Study Group.

[226] APPA at 10–11 (citing *Long-Term Firm Transmission Rights in Organized Electricity Markets,* Order No. 681, FERC Stats. & Regs. ¶ 31,226, at P 319, 320 (2006) (stating that ''a broader preference for load-serving entities in general vis-à-vis non-load-serving entities is fully supported by the statute'' and that ''we believe section 217 of the FPA provides a general 'due' preference for load-serving entities'')); National Rural Electric Coops at 9–10 (citing same).

164. Other petitioners raise concerns about the relationship between section 217(b)(4) and Order No. 1000's requirement that public utility transmission providers consider transmission needs driven by Public Policy Requirements. Large Public Power Council argues that the requirement that public utility transmission providers consider transmission needs driven by Public Policy Requirements runs counter to FPA section 217(b)(4). It argues that imposing such a requirement would result in reconsideration by regional planners of the same matters that resulted in the transmission demand projections by load-serving entities, and is likely to lead to skewed decision-making, reflecting political value judgments and stakeholder business plans. Southern Companies also assert that these requirements violate section 217(b)(4) by hampering their ability to expand the transmission system to meet the needs of their native load by making the transmission planning process more bureaucratic and inefficient.

165. Several petitioners assert that the Commission erred in not stating specifically that FPA section 217(b)(4) is a Public Policy Requirement that must be considered in the transmission planning process.[227] APPA states that this provision is a specific legal directive regarding transmission planning enacted by Congress and imposed on the Commission. Transmission Access Policy Study Group explains that the intent of section 217(b)(4) is to protect all load-serving entities, including transmission dependent utilities, and therefore, failure to include it as a public policy that must be considered in planning sends the message that planning to meet the reasonable needs of transmission dependent load-serving entities is optional in the planning process. Transmission Access Policy Study Group asserts that treating such entities as simply stakeholders whose needs may or may not be considered in the planning process violates section 217(b)(4)'s directive to the Commission to help meet load-serving entities' needs. Ad Hoc Coalition of Southeastern Utilities states that section 217, as the only passage in the FPA that explicitly addresses planning, imposes on the Commission an obligation of a higher order than furthering other public policies not mentioned in the Commission's organic statute. Ad Hoc Coalition of Southeastern Utilities contends that Order No. 1000 fails to facilitate planning to meet native load because it compels load-serving entities to participate in planning processes in which their obligations to serve native load are considered as just one among many public policies goals that may be advanced by stakeholders. Large Public Power Council agrees.

166. Other petitioners argue that the Commission's nonincumbent reforms violate section 217(b)(4) by making it more difficult for them to meet their obligations to serve native load.[228] Southern Companies assert that not only does the Commission lack authority to impose Order No. 1000's nonincumbent transmission developer requirements, but, to the extent it makes it more difficult for Southern Companies to expand their transmission system to meet their native load service obligations, those requirements are prohibited by section 217(b)(4).

167. As for the regional planning process, MISO Transmission Owners Group 2 argues that eliminating the federal rights of first refusal will discourage robust participation in regional transmission planning. It asserts that eliminating the federal right of first refusal provides an incentive for incumbent public utilities with state-imposed retail service obligations that have local transmission planning processes to rely on their local process rather than the regional process to expand their transmission systems to serve their customers and comply with state mandates. It argues the same is true for incumbent public utility transmission providers that are NERC-registered entities that must construct transmission facilities to satisfy reliability standards or avoid NERC penalties. According to MISO Transmission Owners Group 2, this will result in the type of divided, inefficient, and potentially duplicative transmission expansion process that Order No. 1000 purports to discourage, and will create an unreasonable incentive for utilities with local planning processes to favor local projects when a regional solution is warranted.

ii. Commission Determination

168. We deny rehearing. We continue to find that the transmission planning reforms required by Order No. 1000 are consistent with the Commission's obligations under FPA section 217(b)(4). Section 217(b)(4) directs the Commission to exercise its authority under the FPA:

> in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities, and enables load-serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs.[229]

We believe that the regional transmission planning reforms required by Order No. 1000 are consistent with this mandate because they will enhance the transmission planning process for all interested entities, including load-serving entities. We expect that load-serving entities and their customers, like other interested parties, will benefit from a regional planning process that identifies transmission solutions that are more efficient or cost-effective than what may be identified in the local transmission plans of individual public utility transmission providers. For example, we expect that the planning process required by Order No. 1000 will help identify efficient or cost-effective transmission projects that address the transmission needs of load-serving entities and their customers, whether they are driven by reliability, economics, or public policy requirements.

169. The Commission's discussion of the relationship between section 217(b)(4) and the transmission planning reforms undertaken in Order Nos. 890 and 890–A further demonstrate that the Order No. 1000 regional transmission planning reforms are consistent with, and not prohibited by, section 217(b)(4).[230] In Order No. 890–A, the Commission explained that ''[t]ransmission planning activities are within our jurisdiction and, therefore, we have a duty under FPA section 206 to remedy undue discrimination in this area and a further obligation under FPA section 217 to act in a way that facilitates the planning and expansion of facilities to meet the reasonable needs of LSEs [load-serving entities].'' [231] We believe that the discussions in Order Nos. 890 and 890–A apply with equal force here.[232] Contrary to some

[227] *See, e.g.,* Ad Hoc Coalition of Southeastern Utilities; APPA; Large Public Power Council; National Rural Electric Coops; and Transmission Access Policy Study Group.

[228] *See, e.g.,* Baltimore Gas & Electric; and Southern Companies.

[229] 16 U.S.C. 824q(b)(4) (2006).

[230] In Order No. 890, the Commission explained that section 217(b)(4) supported the transmission planning reforms therein. *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 436. Order No. 1000's regional transmission planning reforms require public utility transmission providers to, among other things, adopt Order No. 890 transmission planning principles as part of their regional transmission planning process. Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at PP 150–52.

[231] Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 at P 172.

[232] The Commission discusses its jurisdiction with respect to transmission planning in this rule.

petitioners' arguments, section 217(b)(4) does not limit or prohibit the transmission planning reforms required by Order No. 1000; rather, it directs the Commission to take action to facilitate the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities. While each transmission planning region may conclude that different approaches are best suited to accommodate those needs, we find that the framework we set forth in Order No. 1000 will assist in accomplishing the requirements of section 217(b)(4).

170. As the Commission explained in Order No. 1000, the reforms adopted therein build on the requirements of Order No. 890 and further facilitate open and transparent transmission planning to, a goal that does not conflict with FPA section 217. Indeed, the Commission explained that Order No. 1000 is consistent with section 217, because it supports the development of needed transmission facilities that benefit load-serving entities. The Commission pointed out that the fact that the Order No. 1000 transmission planning reforms serve the interests of other stakeholders as well does not place the Commission's action in conflict with section 217.[233] Nothing in Order No. 1000 is intended to prevent or restrict a load-serving entity from fully implementing resource decisions made under state authority. Rather, the Commission's expectation is that Order No. 1000 will facilitate the evaluation of potential transmission facilities needed to accommodate such resource decisions.

171. We find that assertions made by APPA and National Rural Electric Coops that section 217(b)(4) establishes a preference for load-serving entities are too broad. APPA and National Rural Electric Coops state that Order No. 681, in which the Commission promulgated regulations under section 217(b)(4) regarding long-term firm transmission rights, expressly noted such a preference. However, Order No. 681 made this point in the context of securing long-term firm transmission rights supported by *existing* transmission capacity, which was the subject of that rulemaking proceeding, but not in the broader context of planning new transmission capacity. Specifically, Order No. 681 established a guideline that provided:

> Load-serving entities must have priority over non-load-serving entities in the allocation of long-term firm transmission rights that are supported by existing transmission capacity. The transmission organization may propose reasonable limits on the amount of existing transmission capacity used to support long-term firm transmission rights.[234]

172. We do not find this statement inconsistent with the reforms in Order No. 1000, which address the planning and cost allocation for *new* transmission.[235] In any event, as discussed above, we find that Order No. 1000's transmission planning reforms will aid, not hinder, load-serving entities in meeting their reasonable transmission needs. Thus, nothing in Order No. 1000's transmission planning reforms conflicts with the existing requirements of Order No. 681 regarding the availability of long-term firm transmission rights in organized electricity markets.

173. In addition, by requiring that transmission needs driven by Public Policy Requirements be considered in local and regional transmission planning processes, our expectation is that such a requirement will assist load-serving entities and others in better meeting their transmission needs. For this same reason, we allow but do not require that the coordination of reliability and economic transmission planning include identifying optimal solutions to congestion to ensure that load-serving entities' needs are met under section 217(b)(4), as suggested by Transmission Dependent Utility Systems.

174. We also disagree with Coalition for Fair Transmission Policy's contention that Order No. 1000 may not allow load-serving entities to implement their states' resource decisions. As discussed in the following section, nothing in Order No. 1000 conflicts or interferes with the states' integrated resource planning processes. Accordingly, and for the reasons discussed above, we do not believe that Order No. 1000's requirements conflict with section 217, as some petitioners maintain.

175. We also disagree with petitioners such as Large Public Power Council that the consideration of transmission needs driven by Public Policy Requirements runs counter to section 217(b)(4). First, as we stated above, we find that Order No. 1000 will enhance, not impede, meeting the needs of load-serving entities. We also believe that these specific reforms may assist load-serving entities in meeting their transmission needs, especially because many, if not all, of the Public Policy Requirements will likely impose legal obligations on load-serving entities. Therefore, we see nothing inconsistent between these reforms and section 217(b)(4).

176. We affirm Order No. 1000's conclusion that we will not prescribe any statutes and regulations as Public Policy Requirements for purposes of Order No. 1000, including section 217(b)(4). We explained that we would not pick and choose any federal or state law or regulation as a Public Policy Requirement. Rather, it will be up to public utility transmission providers, in consultation with stakeholders, to develop a process that considers transmission needs driven by Public Policy Requirements.

177. Further, we disagree with NARUC's assertion that, while Order No. 1000 purports to support integrated resource planning, its requirements are contrary to section 217(b)(4)'s requirement of a bottom-up transmission planning process. First, by its terms, section 217(b)(4) does not require a bottom-up transmission planning process, as NARUC claims. Rather, section 217(b)(4) requires the Commission to exercise its authority to facilitate the planning and expansion of transmission facilities to assist load-serving entities in meeting their reasonable transmission needs and to secure long-term firm transmission rights. It does not speak at all to how transmission planning processes should be established. Second, regardless of whether a regional transmission planning process is termed bottom-up or top-down, we emphasize that nothing in any of Order No. 1000's requirements interferes with states' authority to require integrated resource planning or utilities' obligation to comply with such requirements, as discussed herein.

178. We disagree with petitioners that argue that Order No. 1000's nonincumbent transmission developer reforms are prohibited by, or inconsistent with, section 217(b)(4).[236] Contrary to Southern Companies' contention, these reforms do not make it more difficult for incumbent

See Order No. 1000, Stats. & Regs. ¶ 31,323 at section III.A.2; *see also* discussion *supra* at section III.A.1.

[233] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 108.

[234] Order No. 681, FERC Stats. & Regs. ¶ 31,226 at P 325.

[235] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 65 (the requirements of Order No. 1000 are "intended to apply to new transmission facilities, which are those transmission facilities that are subject to evaluation, or reevaluation as the case may be, within a public utility transmission provider's local or regional transmission planning process after the effective date of the public utility transmission provider's filing adopting the relevant requirements" in Order No. 1000).

[236] Other issues regarding Order No. 1000's nonincumbent reforms are discussed in section III.B, *infra*.

transmission providers to serve native load. Indeed, we believe just the opposite to be the case, for as found in Order No. 1000, the Commission believes that greater participation by transmission developers in the transmission planning process may lower the cost of new transmission facilities, enabling more efficient or cost-effective deliveries by load-serving entities and increased access to resources.[237] Accordingly, we expect that incumbent transmission providers will ultimately benefit from these reforms because they support the identification of more efficient or cost-effective transmission solutions, thereby improving their ability to meet the reasonable needs of load-serving entities to satisfy their load serving obligations.

179. We also disagree with MISO Transmission Owners Group 2 that these reforms will necessarily encourage incumbent transmission providers to favor local transmission planning and local transmission projects over regional transmission planning and regional transmission solutions. While nothing in Order No. 1000 prohibits an incumbent transmission provider from proposing a local transmission solution to satisfy a reliability need or service obligation, we are not persuaded that allowing incumbent transmission providers to choose among these options will lead to less robust regional transmission planning. There are a variety of factors that incumbent transmission providers must consider when deciding whether to propose a local transmission facility instead of relying on a transmission facility selected in the regional transmission plan for purposes of cost allocation. We also believe, as discussed in Order No. 1000 and herein, that the nonincumbent transmission developer reforms will lead to more competition among developers, which in turn will lead to the identification of more efficient and cost-effective transmission facilities. Accordingly, we are not persuaded that the elimination of a federal right of first refusal will necessarily will lead to inefficient or duplicative transmission planning processes.

d. Effect on Integrated Resource Planning and State Authority Over Transmission Siting, Permitting, and Construction

i. Requests for Rehearing and Clarification

180. Several state regulators and others claim that Order No. 1000 improperly intrudes on authority over matters traditionally reserved to the states, such as integrated resource planning and the construction and siting of transmission facilities.[238] North Carolina Agencies and Southern Companies argue that, in contrast to the extensive jurisdiction over transmission planning historically exercised by the states, the FPA grants the Commission little, if any, authority in this area. Florida PSC and Georgia PSC also state that FPA section 201(a) limits the Commission's authority to regulate interstate transmission and wholesale power sales to only those matters that are not subject to state regulation, and that the Commission provided no evidence of discrimination to support preempting state authority over transmission planning.[239]

181. Several petitioners argue that Order No. 1000's planning reforms will disrupt, and potentially preempt, a state's integrated resource planning.[240] For example, Georgia PSC states that if regional and interregional transmission planning and coordination requirements result in a previously unidentified transmission project being included in a Commission-regulated process, that result will disrupt and skew existing state-regulated transmission and integrated resource planning processes, and will undermine its ability to effectively regulate bundled retail service.

182. Similarly, Alabama PSC contends that least-cost, reliable solutions identified for its ratepayers through integrated resource planning will be subordinated to the solutions identified for the region under the Commission-administered process, with no assurance that this regional solution will hold local ratepayers harmless. NV Energy also asserts that inclusion of alternative transmission and non-transmission proposals in the regional or interregional plan could trump a transmission facility in a local plan, rendering the state's integrated resource planning process meaningless.[241] NV Energy contends that this could lead to ''forum shopping,'' particularly in the case of considering Public Policy Requirements, and that states may be reluctant to approve the siting of facilities that are the result of a process of exclusion or substitution of facilities that they deem necessary and appropriate in their integrated resource planning processes.[242] NV Energy thus seeks clarification that for any facilities included in a ''local'' plan, those facilities are not subject to ''de novo'' review at the regional or interregional level unless the transmission provider voluntarily subjects the facilities to an alternative review or the facilities are proposed by the transmission provider for regional cost allocation and they are so chosen.[243] Coalition for Fair Transmission Policy seeks clarification that regional transmission planning processes and interregional transmission coordination do not have the ability or authority to affect or change resource decisions made by entities with responsibility to meet public policy requirements and the transmission needs that they have identified associated with those resource decisions, except with the voluntary agreement of those responsible entities.

183. Kentucky PSC argues that Order No. 1000 infringes on state jurisdiction over integrated resource planning through its failure to require transmission planning and cost allocation processes to allow for the unique role of state regulators in determining which projects will be constructed and who will pay for them. Kentucky PSC notes that in Kentucky, only the state legislature can decide if in-state utilities must use certain proportions of various types of energy resources. It maintains that a decision to develop a transmission facility might *de facto* make decisions about types and locations of generation resources. Kentucky PSC also argues that Order No. 1000 erred regarding the consideration of non-transmission alternatives, asserting that such matters are within the exclusive province of state-regulated integrated resource planning.[244]

184. Some petitioners, such as Ad Hoc Coalition of Southeastern Utilities, argue that regional cost allocation determinations under Order No. 1000 will have a preemptive effect on decisions made at the state level. Ad Hoc Coalition of Southeastern Utilities asserts that if ratepayers must pay for a nonincumbent's transmission line

[237] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 291.

[238] *See, e.g.,* NARUC; Florida PSC; Alabama PSC; Georgia PSC; Kentucky PSC; North Carolina Agencies; Large Public Power Council; Ad Hoc Coalition of Southeastern Utilities; Southern Companies; and Coalition for Fair Transmission Policy.

[239] In relevant part, FPA section 201(a) provides that federal regulation over the interstate transmission and wholesale sale of electric energy only ''extend[s] to those matters which are not subject to regulation by the States.'' 16 U.S.C. 824(a).

[240] *See, e.g.,* Ad Hoc Coalition of Southeastern Utilities; Alabama PSC; Georgia PSC; and Southern Companies.

[241] *See also* Coalition for Fair Transmission Policy at 27 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 154).

[242] NV Energy at 7–8.

[243] NV Energy at 9.

[244] *See also* Alabama PSC at 3–4.

chosen in the regional planning process, it would be difficult for the incumbent owner to pursue an alternate project, resulting in the indirect regulation of actual transmission planning decisions, including siting, construction, permitting, and resource planning decisions. It states that the Commission is prohibited from doing indirectly what it is prohibited from doing directly.[245] Ad Hoc Coalition of Southeastern Utilities also states that if the Commission states on rehearing that it does not regulate substantive planning, then it should explain the ramifications of a transmission provider not implementing the regional transmission plan. Southern Companies raise the same argument, emphasizing that the decision to fund transmission projects determines the projects to be pursued.

185. Ad Hoc Coalition of Southeastern Utilities assert that Order No. 1000's regional and interregional processes will likely result in more long distance transmission lines, which could prove to be disruptive to a bottom-up integrated resource planning process due to its significant impacts on bulk power flows.

ii. Commission Determination

186. As we stated in Order No. 1000, nothing therein is intended to preempt or otherwise conflict with state authority over the siting, permitting, and construction of transmission facilities or over integrated resource planning and similar processes. Order No. 1000 explained that ''nothing in this Final Rule involves an exercise of siting, permitting, and construction authority. The transmission planning and cost allocation requirements of this Final Rule, like those of Order No. 890, are associated with the processes used to identify and evaluate transmission system needs and potential solutions to those needs.'' Order No. 1000 concluded that ''[t]his in no way involves an exercise of authority over those specific substantive matters traditionally reserved to the states, including integrated resource planning, or authority over such transmission facilities.''[246]

187. We affirm that conclusion here. In so finding, we recognize, as we did in Order No. 1000, that the states have a significant jurisdictional role in the siting, permitting, and construction of transmission facilities, and that many states require public utility transmission providers to undertake and implement integrated resource plans. However, as we explain below, the Commission may undertake Order No. 1000's reforms without intruding on state jurisdiction.

188. At the outset, it is important to recognize that Order No. 1000's transmission planning reforms are concerned with process; these reforms are not intended to dictate substantive outcomes, such as what transmission facilities will be built and where.[247] We recognize that such decisions are normally made at the state level.[248] Rather, Order No. 1000's transmission planning reforms are intended to ensure that there is an open and transparent regional transmission planning process that produces a regional transmission plan. If public utility transmission providers' regional transmission processes satisfy these requirements, then they will be in compliance with Order No. 1000's regional transmission planning requirements. Thus, contrary to arguments raised by some state regulators and others, Order No. 1000's transmission planning reforms respect the jurisdictional authority of the states regarding the siting, permitting, and construction of transmission facilities.

189. In support of their contention that Order No. 1000 infringes on state authority, North Carolina Agencies claim that the *SMD White Paper* expressly acknowledged that the planning aspects of the SMD proposal infringed on state jurisdiction over transmission planning. The content of the *SMD White Paper* is not relevant to this proceeding.[249] There is nothing in Order No. 1000 that preempts state authority regarding transmission planning, including authority over the siting, permitting, and construction of transmission facilities.

190. By requiring public utility transmission providers to participate in an open and transparent regional transmission planning process that leads to the development of a regional transmission plan, the Commission has facilitated the identification and evaluation of transmission solutions that may be more efficient or cost-effective than those identified and evaluated in the local transmission plans of individual public utility transmission providers.[250] This will provide more information and more options for consideration by public utility transmission providers and state regulators and, therefore, can hardly be seen as detrimental to state-sanctioned integrated resource planning. Of course, we recognize that a regional transmission planning process may not identify any such transmission facilities and, even where more efficient or cost-effective transmission solutions are identified and selected in the regional transmission plan for purposes of cost allocation, such solutions may not ultimately be constructed should the developer not secure the necessary approvals from the relevant state regulators. Consistent with this, we also clarify that we do not require that the transmission facilities in a public utility transmission provider's local transmission plan be subject to approval at the regional or interregional level, unless that public utility transmission provider seeks to have any of those facilities selected in the regional transmission plan for purposes of cost allocation.

191. Accordingly, in response to Ad Hoc Coalition of Southeastern Utilities, we disagree that we are effectively making decisions about which transmission facilities will be sited and constructed, that we are effectively preempting state decisions in that regard, or that we are doing anything indirectly that we cannot do directly. As discussed above, we conclude that we possess ample legal authority under the FPA to implement Order No. 1000's transmission planning reforms. As we also explain immediately above, nothing in Order No. 1000 explicitly or implicitly requires that any transmission facilities be sited, permitted, or constructed. We do not see that decisions made in the regional transmission planning process would interfere with these state-jurisdictional processes. Further, in response to Ad Hoc Coalition of Southeastern Utilities' question regarding the implications of not implementing the regional transmission plan, we reiterate that Order No. 1000 requires a regional transmission plan be developed

[245] Ad Hoc Coalition of Southeastern Utilities at 43–44 (citing generally *Towns of Concord, Norwood, and Wellesley, Mass.* v. *FERC,* 955 F.2d 67, 71 n.2 (D.C. Cir. 1992)).

[246] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 107.

[247] *Id.* P 113 (''This Final Rule is focused on ensuring that there is a fair regional transmission planning *process,* not substantive outcomes of that process.'') (emphasis in original).

[248] The Commission has limited backstop transmission siting authority under section 216 of the FPA. However, that limited authority is not at issue in this proceeding. In response to NARUC, we clarify that nothing in Order No. 1000 is intended to leverage the regional transmission planning or interregional transmission coordination reforms to exceed the Commission's section 216 backstop authority.

[249] In addition, what North Carolina Agencies actually cite to is a brief summary of arguments that the *SMD White Paper* proceeds to address.

[250] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 146 (''We determine that such [regional] transmission planning will expand opportunities for more efficient and cost-effective transmission solutions for public utility transmission providers and stakeholders. This will, in turn, help ensure that the rates, terms and conditions of Commission-jurisdictional services are just and reasonable and not unduly discriminatory or preferential.'').

pursuant to a Commission-approved process, the Commission is not requiring that such a plan be filed for Commission approval or be implemented. Rather, as was made clear in Order No. 1000, the designation of a transmission project as a ''transmission facility in a regional transmission plan'' or a ''transmission facility selected in a regional transmission plan for purposes of cost allocation'' only establishes how the developer may allocate the costs of such a facility in Commission-approved rates if it is built.[251] Order No. 1000, however, does not require that such facilities be built, give any entity permission to build a facility, or relieve a developer from obtaining any necessary state regulatory approvals.[252]

192. We disagree with Ad Hoc Coalition of Southeastern Utilities that the Order No. 1000 transmission planning reforms will be disruptive to integrated resource planning due to the impact of long-distance transmission lines on bulk power flows. Some public utility transmission providers may be concerned that Order No. 1000, because it provides for transmission facilities being selected in the regional transmission plan for purposes of cost allocation, establishes an incentive for other entities to propose larger regional transmission projects that may disrupt or interfere with state-level integrated resource planning efforts. Even if such an incentive were present, we note that unless a long-distance transmission solution identified in the regional transmission planning process is a more efficient or cost-effective solution than what is identified in the local transmission plans of individual public utility transmission providers, it would not be selected in the regional transmission plan for purposes of cost allocation.

193. We also disagree with Kentucky PSC that Order No. 1000's direction that public utility transmission providers, in consultation with stakeholders, consider non-transmission alternatives is outside of the Commission's jurisdiction. We do not require anything more than considering non-transmission alternatives as compared to potential transmission solutions, similar to what was developed in Order No. 890, Order No. 890–A, and resulting compliance filings.[253] The evaluation of non-transmission alternatives as part of the regional transmission planning process does not convert that process into integrated resource planning. Order No. 1000 requires that there be a regional transmission plan that includes transmission facilities selected in the regional transmission plan for purposes of cost allocation.[254]

194. In further response to those petitioners who claim that Order No. 1000 will disrupt state integrated resource planning, we note that the identification of more efficient or cost-effective transmission facilities through a regional transmission planning process should not disrupt state integrated resource planning. In any event, we find that such concerns are speculative and, should they arise, it will be in the context of a specific factual circumstance. If any issues arise in such a context, affected parties are free to raise these issues before the Commission in the appropriate proceeding.

e. Legal Authority Related to Consideration of Transmission Needs Driven by Public Policy Requirements

i. Requests for Rehearing and Clarification

195. Several petitioners express concerns about the Commission's legal authority to require public utility transmission providers to consider transmission needs driven by Public Policy Requirements, arguing that the Commission failed to meet its burden, and that the requirements raise federalism issues and go beyond the Commission's statutory authority.

196. PPL Companies assert that while the Commission may permit public utility transmission providers to consider Public Policy Requirements on a voluntary basis, it erred in mandating such consideration without first finding that existing rates are unjust, unreasonable, or unduly discriminatory. They assert that the Commission has not met its FPA section 206 burden to explain why consideration of transmission needs driven by Public Policy Requirements will remedy unjust and unreasonable rates or undue discrimination. They argue that having to plan for and construct such public policy-driven transmission projects could unduly burden utilities and their customers with additional unjust and unreasonable costs that would not likely have been incurred but for the Public Policy Requirements.

197. ELCON, AF&PA, and the Associated Industrial Groups argue that, by allowing one state's public policy agenda to adversely affect electricity prices in other states that do not share that agenda, Order No. 1000 raises significant federalism issues. They claim that this obscures political accountability because ISOs/RTOs will have discretion to determine which public policy to follow, and that this approach permits the federal government to burden state taxpayers with onerous, unpopular policies or force them to subsidize the public policy decisions of neighboring states without facing the political accountability that federalism demands. They state that the federal government cannot commandeer state legislatures and state executives in the name of federal interests.[255] Alabama PSC raises similar concerns.

198. PPL Companies argue that the FPA does not permit utilities, or the Commission, to pursue public policy objectives broadly, and such a departure from the FPA requires an amendment to the statute itself and cannot be undertaken by the Commission via rulemaking.[256] PSEG Companies contend that the Commission acted outside the scope of its authority, arguing that there is no statute authorizing the Commission to require that transmission providers build public policy projects or even consider Public Policy Requirements. They also argue that, in the absence of specific findings of undue discrimination in a particular region, the Commission should leave it to transmission providers to determine if there is a problem that needs to be

[251] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 66.

[252] *Id.*

[253] *Id.* P 155 n. 149 (citing to Commission orders addressing Order No. 890 compliance filings that require the evaluation of transmission, generation, and demand response on a comparable basis in the public utility transmission providers' transmission planning process).

[254] It may be the case that non-transmission alternatives may result in a regional transmission planning process deciding that a proposed transmission facility is not a more efficient or cost-effective solution and, accordingly, that facility may not be selected in the regional transmission plan for purposes of cost allocation. Such a decision by the regional transmission planning process does not interfere with integrated resource planning.

[255] ELCON, AF&PA, and the Associated Industrial Groups at 10 (quoting *New York* v. *United States,* 505 U.S. 144 (1992)); *see also* PSEG Companies at 45.

[256] PPL Companies at 10–11 (citing *NAACP* v. *FPC,* 425 U.S. 662, 669–70 (1976) (explaining why Congress' direction for the Commission to act in furtherance of the public interest under the FPA ''is not a broad license to promote the general welfare''); *Atlantic City,* 295 F.3d at 8 (explaining that, as a federal agency, the Commission is a ''creature of statute,'' having ''no constitutional or common law existence or authority, but only those authorities conferred upon it by Congress.'' (quoting *Michigan* v. *EPA,* 268 F.3d 1075, 1081 (D.C. Cir. 2001) (emphasis added)); *Louisiana Pub. Serv. Comm'n* v. *FCC,* 476 U.S. 355, 374 (1986) (recognizing that ''an agency literally has no power to act * * * unless and until Congress confers power upon it''); *American Petroleum Inst.* v. *EPA,* 52 F.3d 1113, 1119–20 (D.C. Cir. 1995) (stating that in the absence of statutory authorization for its act, an agency's ''action is plainly contrary to law and cannot stand''); *Ethyl Corp.* v. *EPA,* 51 F.3d 1053, 1060 (D.C. Cir. 1995)).

addressed through revisions to the planning process and, if necessary, develop solutions that do not get ahead of states' efforts to implement their own public policies. They argue that the requirement that transmission providers prognosticate public policy outcomes and plan the system based on those predictions is not proportional to the alleged problem and is thus impermissible.[257] They also allege that the Commission did not explain how and why the existing construct focusing on the planning of reliability and economic projects has not served the needs of load-serving entities.

199. Ad Hoc Coalition of Southeastern Utilities and Large Public Power Council assert that the Commission exceeded its authority under the FPA, as delineated in *NAACP* v. *FPC,* by directing transmission providers to consider Public Policy Requirements in the planning process. Ad Hoc Coalition of Southeastern Utilities argues that although Congress directs the Commission to act in furtherance of the public interest, it is not a broad license to promote the general public welfare.[258] Instead, it asserts that public interest must be understood in the context of the broad goals of the FPA itself—to ensure the provision of reliable transmission service on a non-discriminatory basis, at just and reasonable rates. Thus, it argues that the Commission lacks authority to consider broad concepts of public policy in implementing its duties under the FPA, and may not promulgate rules advancing environmental goals. It notes that the Commission has recognized that its NEPA-related responsibilities to consider environmental policy objectives do not extend to section 205 rate filings.[259]

200. Southern Companies argue that the Commission lacks authority under the FPA to enforce and implement state and federal policies, which violates *Comcast* v. *FCC.*[260] They add that Order No. 1000's regulation of specific evaluative practices violates precedent establishing that the Commission cannot regulate a matter just because the Commission is able to articulate some relationship between that matter and the Commission-regulated, wholesale electric and transmission services.[261] They assert that the Commission's reading of the holding of *CAISO* v. *FERC,* which it interprets as giving it authority to control anything that affects the need for interstate transmission facilities, is too broad since all aspects of our modern, electricity-consuming lives drive the need for interstate transmission facilities.[262]

201. Southern Companies asserts that Public Policy Requirements are merely components that drive load growth and resource decisions that are the major aspects of integrated resource planning, which demonstrates that addressing Public Policy Requirements is an issue for state-regulated integrated resource planning. In addition, they state that even though it already incorporates public policies into its transmission planning process, Order No. 1000's Public Policy Requirement appears to add nothing but costs and burdens by mandating nothing more than compliance activities. Therefore, Southern Companies argue that Order No. 1000's Public Policy Requirements are arbitrary and capricious,[263] and violate *National Fuel.*[264]

202. Bonneville Power seeks clarification that the Public Policy Requirement reforms to its local planning process must be consistent with its statutory authorities related to providing regional and interregional transmission facilities.[265] Bonneville Power states that its statutory authorities for planning and building transmission facilities are not constrained by the FPA's just and reasonable and not unduly discriminatory standard. It also explains that while its Administrator may consider policies at play under those standards, he must also factor in other considerations.[266] If the Commission declines to grant this clarification, Bonneville Power seeks rehearing, arguing that the Commission failed to provide reasonable notice of the requirement and failed to consider Bonneville Power's comments and statutory requirements.

ii. Commission Determination

203. We deny rehearing. Many of the arguments raised on rehearing simply repeat assertions made by commenters in response to the Proposed Rule in this proceeding, namely, that the Commission is not permitted to require public utility transmission providers to consider transmission needs driven by public policy under the FPA or that the direction to public utility transmission providers to consider transmission needs driven by Public Policy Requirements is not a practice affecting rates.

204. At the outset, it is important to emphasize exactly what these reforms are intended to do and what they clearly are not intended to do. As explained in Order No. 1000, in requiring the consideration of transmission needs driven by Public Policy Requirements, the Commission is not mandating fulfillment of those requirements or that public utility transmission providers consider the Public Policy Requirements themselves. We address this issue in more detail below,[267] but we clarify here the basic components of Order No. 1000's requirements in this regard, as it appears there are misconceptions about precisely what Order No. 1000 requires. To be clear, we are not requiring that any federal or state laws or regulations themselves be considered as part of the transmission planning process. That distinction is critical, and we want to be clear that this is not what Order No. 1000 requires.[268]

205. Instead, the Commission is acknowledging that the requirements in question are facts that may affect the need for transmission services and these facts must be considered for that reason. Our intent is that public utility transmission providers consider such transmission needs just as they consider transmission needs driven by reliability or economic concerns.[269] We are not

[257] PSEG Companies at 47 (citing *California Indep. Sys. Operator Corp.* v. *FERC,* 372 F.3d 395 (D.C. Cir. 2004) (*CAISO* v. *FERC*)).

[258] Ad Hoc Coalition of Southeastern Utilities at 53 (citing *NAACP* v. *FPC,* 425 U.S. 662, 665 (1976)).

[259] Ad Hoc Coalition of Southeastern Utilities at 54 (citing, e.g., *Monongahela Power Co.,* 39 FERC ¶ 61,350, at 62,097, *reh'g denied,* 40 FERC ¶ 61,256 (1987) (*Monongahela*); 18 CFR 380.4(a)(15) (2011)). *See also* Large Public Power Council.

[260] Southern Companies at 51 (citing *Comcast Corp.* v. *FCC,* 600 F.3d 642, 659 (D.C. Cir. 2010)).

[261] Southern Companies at 51 (quoting *State of Missouri* v. *Southwestern Bell Tel. Co.,* 262 U.S. 276, 289 (1923) (stating that a regulatory agency with general oversight and rate authority "is not the owner of the property of public utility companies, and is not clothed with the general power of management incident to ownership") (*Southwestern Bell*)).

[262] Southern Companies at 52 (citing *CAISO* v. *FERC,* 372 F.3d 395).

[263] Southern Companies at 50 (citing *Motor Vehicles Mfrs. Ass'n of the U.S.* v. *State Farm Mutual Auto. Ins. Co.,* 463 U.S. 29, 43 (1983)).

[264] Southern Companies at 50 (citing *National Fuel,* 468 F.3d at 844).

[265] Bonneville Power at 21. Bonneville Power states that it is only requesting clarification with respect to its local planning process rather than with respect to the regional planning process in which it voluntarily participates. Bonneville Power at 22.

[266] Bonneville Power states that Congress recognized this in section 1232 of EPAct 2005, which provides that if Bonneville Power enters into a contract, agreement, or arrangement for participation in a transmission organization, then it must assure, among other things, "consistency with the statutory authorities, obligations, and limitations of the federal utility." Bonneville Power at 22 (quoting 42 U.S.C. § 16431(c)(1)(C)).

[267] *See* discussion *infra* at section III.A.2.

[268] *See* discussion *infra* at section III.A.2.

[269] We note that this is consistent with the approach taken in Order No. 888, and reiterated in Order No. 890, that public utility transmission providers are obligated to plan for the needs of their

Continued

requiring that public utility transmission providers do any more than that. Such requirements may modify the need for and configuration of prospective transmission facilities. Accordingly, the transmission planning process and the resulting transmission plans would be deficient if they do not provide an opportunity to consider transmission needs driven by Public Policy Requirements.[270] As a result, in Order No. 1000 we acted pursuant to our section 206 authority to ensure that this deficiency is remedied in the OATTs of public utility transmission providers.

206. We thus disagree with PSEG Companies that Order No. 1000's requirements in this regard are impermissible because the remedy is disproportionate to the identified problem. Again, we are requiring only that there be a process in place for public utility transmission providers, in consultation with stakeholders, to consider transmission needs driven by Public Policy Requirements. We believe that these reforms are necessary, because the record shows that there are, and there will continue to be, federal and state laws and regulations that will have a direct impact on transmission needs, just as reliability and economic concerns have a direct impact on transmission needs. By setting forth this process, our expectation is that public utility transmission providers, in consultation with stakeholders, will identify more efficient or cost-effective solutions to such transmission needs than may be the case without these requirements.

207. Given the parameters described above, and discussed in more detail below,[271] we do not see how these reforms are comparable to the matters at issue in *NAACP* v. *FPC.* As discussed in Order No. 1000, the Court in *NAACP* v. *FPC* found that the Commission did not have the power under the FPA or the Natural Gas Act (NGA) to construe its obligation to promote the public interest under those statutes as creating a ''broad license to promote general public welfare.'' [272] The Court also found that the Commission's duty to promote the public interest under the FPA and NGA ''is not a directive to the Commission to seek to eradicate discrimination,'' and it thus did not authorize the Commission to promulgate rules prohibiting the companies it regulates from engaging in discriminatory employment practices merely because the statutes pertain to matters affected with a public interest.[273] We reiterate here that the consideration of transmission needs driven by Public Policy Requirements ''cannot be construed as pursuing broad general welfare goals that extend beyond matters subject to our authority under the FPA.'' [274]

208. The planning necessary to consider transmission needs driven by Public Policy Requirements is not different in substance from the planning required to address reliability or economic needs. Such planning requires an open and transparent process that provides interested stakeholders with access to studies, models and data used to make decisions. This transparency and coordination helps to ensure no undue discrimination on the part of the public utility transmission provider in planning for its own needs vis-à-vis the needs of customers to which it is obligated to provide open access transmission service. Thus, we disagree with petitioners that suggest that Order No. 1000's requirements in this regard are analogous to promoting broad notions of public policy, as contemplated in *NAACP* v. *FPC.*

209. Similarly, we find that references to the Commission's order in *Monongahela* are not relevant here. In that case, the Commission explained that we ''have consistently recognized that [our] review of electric rate filings is not subject to NEPA,'' [275] and we then rejected arguments by an environmental advocacy group that the Commission curtail the operation of existing but unused capacity within a transmission provider's system. We stated that ''[b]ecause the Commission does not possess such curtailment authority by virtue of section 201(b) of the FPA, it could not accomplish indirectly through NEPA that which it is prohibited from doing directly under section 201(b) of the FPA.'' [276] Nothing in Order No. 1000 contradicts these statements. Similar to our discussion above that we are not promoting broad notions of public policy, we emphasize that we are not advocating for any particular environmental or other public policy and we are not requiring electric rate filings under section 205 to be subjected to NEPA. We are requiring only that transmission needs driven by Public Policy Requirements be considered in transmission planning processes, just as public utility transmission providers consider reliability- and economic-based transmission needs.

210. Further, we disagree with Southern Companies that our actions in this regard are akin to what was at issue in *CAISO* v. *FERC.* As explained in Order No. 1000, in that case, the court found that the Commission did not have the authority under section 206 of the FPA to direct the California ISO to alter the structure of its corporate governance, concluding that the choosing and appointment of corporate directors is not a ''practice * * * affecting [a] rate'' within the meaning of the statute.[277] The court explained that the Commission is empowered under section 206 to assess practices that directly affect or are closely related to a public utility's rates and ''not all those remote things beyond the rate structure that might in some sense indirectly or ultimately do so.'' [278] As we explained in Order No. 1000, the transmission planning activities that are the subject of the rule have a direct and discernable effect on rates.[279] These reforms are intended to help create a path to allow public utility transmission providers, in consultation with stakeholders, in each transmission planning region to assess what transmission needs are being driven by Public Policy Requirements, just as they currently look to whether transmission needs are driven by reliability or economic considerations.

211. Similarly, our actions in this regard are not contrary to the Supreme Court's opinion in *Southwestern Bell,* which was cited by Southern Companies. We are ''not the owner of the property of public utility companies'' and we are ''not clothed with the general power of management incident to ownership,'' and nothing in these rules provide the Commission with such authority.[280] We are, as we discuss herein, providing for the consideration of transmission needs driven by Public Policy Requirements, just as public utility transmission providers consider transmission needs driven by reliability or economics. That direction is not tantamount to directing public utility transmission providers how to manage their property.

212. Because, as discussed herein, we have statutory authority to implement these reforms, we disagree with Southern Companies' that Order No. 1000 is contrary to *Comcast* v. *FCC,* where the court concluded that the

transmission customers. *See, e.g.,* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at PP 418–19.

[270] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 109.

[271] *See* discussion *infra* at section III.A.3.

[272] *NAACP* v. *FERC,* 425 U.S. 662 at 668.

[273] *Id.* at 670.

[274] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 111.

[275] *Monongahela,* 39 FERC ¶ 61,350 at 62,097

[276] *Id.*

[277] *CAISO* v. *FERC,* 372 F.3d at 403.

[278] *Id.*

[279] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 112.

[280] *Southwestern Bell,* 262 U.S. at 289.

Federal Communications Commission (FCC) lacked requisite statutory authority to regulate an Internet service provider's network management practices. The court explained that the FCC could not rely on policy statements in the Communications Act of 1934 by themselves as the basis for the FCC to exercise ancillary authority to regulate Internet service, noting that policy statements are not delegations of regulatory authority.[281] The court also found that the FCC's reliance on other statutory provisions failed because the agency was using its ancillary authority to pursue standalone policy objectives rather than to support its exercise of a delegated power.[282] By contrast, the Commission's transmission planning reforms, including those related to Public Policy Requirements, fall within the Commission's statutorily mandated duties under the FPA, as discussed above. Thus, the Commission is not relying on ancillary authority to pursue standalone policy objectives, much less basing its actions on broad statements of Congressional policy.

213. We disagree with ELCON, AF&PA, and Associated Industrial Groups that Order No. 1000's requirements regarding Public Policy Requirements raise significant federalism issues. As a factual matter, there are significant differences between what we are requiring in Order No. 1000 and the decision in *New York* v. *U.S.,* which petitioners cite in support of their federalism argument. In that case, the Supreme Court held that the federal government could not compel states to implement a federal regulatory program.[283] That is not what is at issue here. Instead, Order No. 1000 requires that local and regional transmission planning processes consider transmission needs driven by Public Policy Requirements. This requirement is directed to public utility transmission providers, which are subject to the Commission's FPA jurisdiction, and not states. States are not required to implement any action.

214. Petitioners' federalism argument focuses more on the allocation of costs associated with transmission facilities developed in response to Public Policy Requirements that are selected in the regional transmission plan for purposes of cost allocation. But it is unclear how petitioners can reasonably make the leap from the federal commandeering of state legislatures at issue in *New York* v. *U.S.* to the requirement that costs for transmission needs driven by Public Policy Requirements be allocated pursuant to an Order No. 1000-compliant cost allocation method. As discussed below, it may or may not be the case that entities in one state benefit from a new transmission facility built in response to another state's Public Policy Requirement, in accordance with a transmission planning region's regional cost allocation method. For example, a transmission facility selected in a regional transmission plan for purposes of cost allocation that was in the first instance advanced to meet the transmission needs driven by a particular state's Public Policy Requirement may also provide reliability or economic benefits to entities located outside of that state. We do not see how a regional cost allocation method making such a finding equates with the commandeering of states by the federal government or that this is tantamount to requiring the states to implement a federal regulatory program. Rather, this simply ensures that costs are allocated to all those entities that benefit from any given transmission facility that is selected in a regional transmission plan for purposes of cost allocation, regardless of whether those benefits are reliability, economic, or related transmission needs driven by Public Policy Requirements.

215. Next, we disagree with Southern Companies that the consideration of transmission needs driven by Public Policy Requirements interferes with integrated resource planning. First, as we explain above, Order No. 1000 does not infringe on integrated resource planning. States can continue to require utilities under their jurisdiction to engage in integrated resource planning, and nothing in Order No. 1000 changes that or otherwise negates those state-level resource decisions. Second, with respect to these specific reforms, we note that this requirement is a tool for public utility transmission providers to consider transmission needs that may not be captured under existing transmission planning processes, which are focused on reliability and economic needs. If the transmission planning process does consider additional transmission needs, i.e., those driven by Public Policy Requirements, that does not mean this interferes with state-level integrated resource planning, just as those existing transmission planning processes do not interfere today.

216. We clarify that, for entities such as Bonneville Power, which may be subject to their own organic statutes and regulations, nothing in Order No. 1000's reforms regarding the consideration of transmission needs driven by Public Policy Requirements is intended to preempt those organic statutes or regulations. We believe that this should address Bonneville Power's concern.

f. Legal Issues Related to Order No. 1000's Interregional Transmission Coordination Reforms

i. Requests for Rehearing and Clarification

217. While most rehearing requests address legal issues associated with transmission planning in general, some petitioners raise legal issues specifically related to Order No. 1000's interregional transmission coordination reforms.

218. Some petitioners argue that the Commission lacks authority to require transmission providers to engage in interregional coordination.[284] Xcel, for example, argues that the Commission has not adequately explained how interregional transmission planning activities of public utilities directly affect jurisdictional rates. It asserts that under a planning process no rate is charged and no transmission customer is in privity to the transmission owner. California ISO asserts that it is not precluded from arguing that the Commission's interregional planning requirements in Order No. 1000 are beyond its authority based on the fact that it did not seek judicial review of the transmission planning provisions of Order No. 890.

219. Ad Hoc Coalition of Southeastern Utilities and Southern Companies assert that the Commission has not historically required transmission planning and coordination agreements to be filed, and argues that it is arbitrary and capricious for the Commission to determine now that such agreements are jurisdictional under section 205. They state that the Commission did not include transmission planning and coordination agreements among the type of agreements that are listed as jurisdictional in the Commission's *Prior Notice* order.[285] Ad Hoc Coalition of Southeastern Utilities adds that this is logical because the penalty for untimely filings of jurisdictional agreements, i.e., the payment of a refund to the affected customer in the form of interest on the payments received over the period that the jurisdictional agreement was not on file, would not apply to a transmission

[281] *Comcast* v. *FCC,* 600 F.3d at 654–55.

[282] *Id.* at 658–61.

[283] *New York* v. *U.S.,* 505 U.S. at 151.

[284] *See, e.g.,* Ad Hoc Coalition of Southeastern Utilities; California ISO; Southern Companies; and Xcel.

[285] Ad Hoc Coalition of Southeastern Utilities at 63–64; Southern Companies at 85 (citing *Prior Notice and Filing Req'ts Under Part II of the Fed. Power Act,* 64 FERC ¶ 61,139 (1993) (*Prior Notice Order*)).

coordination planning agreement.[286] For example, because there are no rates or payments in a transmission planning or coordination agreement, it asserts that there would be no penalty, which reinforces its claim that the Commission has no jurisdiction over such agreements for purposes of section 206.

220. WIRES states that section 206 requires the Commission to indicate what measures will cure the practical and legal deficiencies in interregional planning and to order industry to make curative filings, not to ask industry to spend months in effect deciding what will satisfy the FPA. Moreover, it states that ordering regulated entities to make filings under section 205 is impermissible. It therefore contends that Order No. 1000 lacks substantial evidence for this approach and is not the result of reasoned decision-making.

221. Bonneville Power seeks clarification that the formal procedure required by Order No. 1000 to identify and jointly evaluate transmission facilities that are proposed to be located within adjacent transmission planning regions may be established in a manner that allows Bonneville Power to identify and evaluate the interregional facility in an open and transparent process in accordance with its statutory authority.[287] Alternatively, it requests rehearing of the Commission's rejection of Bonneville Power's concerns on the grounds that the Commission's decision is arbitrary and capricious and violates the Administrative Procedure Act. Bonneville Power argues that, if the requirement for a formal procedure to identify and jointly evaluate proposed interregional facilities includes details about how the facilities will be planned and developed, then the Commission effectively ignored Bonneville Power's comment without explanation. Bonneville Power asserts that the Commission's requirement, in effect, impermissibly requires non-public utilities to adhere to the FPA requirements applicable to public utilities, which it believes will have a chilling effect on non-public utility participation in regional planning process, contrary to the Commission's goal of broad-based participation. Bonneville Power also argues that the Commission lacks authority to require it to accept regulations under sections 205 and 206 as a condition of its participation in regional or interregional transmission planning.

ii. Commission Determination

222. We affirm our legal authority to undertake Order No. 1000's reforms regarding interregional transmission coordination. We disagree with Xcel that we have not explained how interregional transmission coordination is a practice affecting jurisdictional rates. Similar to our regional transmission planning reforms, the Commission found that the interregional transmission coordination reforms will help to identify transmission facilities that may be more efficient or cost-effective than what individual transmission planning regions may identify, thereby helping to ensure that jurisdictional rates for transmission service are just and reasonable and not unduly discriminatory or preferential.

223. Further, we disagree with WIRES that we cannot undertake the interregional transmission coordination reforms as set forth in Order No. 1000. Order No. 1000 requires that the public utility transmission providers in each pair of neighboring transmission planning regions, working through their regional transmission planning processes, must develop the same language to be included in each public utility transmission provider's OATT that describes the interregional transmission coordination procedures for that particular pair of regions, or alternatively, to enter into interregional coordination agreements.[288] In doing so, the Commission is allowing public utility transmission providers in the first instance to negotiate the terms of the common OATT language or agreements, so long as they meet the minimum requirements set forth in Order No. 1000. This approach is consistent with the regional flexibility provided elsewhere in Order No. 1000. WIRES offers no compelling reason that we should depart from that approach here. The Commission has taken appropriate action under FPA section 206 to undertake the interregional transmission coordination reforms. While we provide flexibility and, therefore, allow public utility transmission providers the ability to craft agreements that take into account their needs and the needs of their stakeholders, it is important to note that the Commission will review each compliance filing to ensure that they are just and reasonable and not unduly discriminatory or preferential.

224. We also disagree with Ad Hoc Coalition of Southeastern Utilities and Southern Companies that it is arbitrary and capricious to require public utility transmission providers to file interregional transmission coordination agreements. As an initial matter, as noted above, the Commission does not require that public utility transmission providers enter into interregional transmission coordination agreements to comply with Order No. 1000, though they may do so. Rather, public utility transmission providers must develop common OATT language that implements Order No. 1000's interregional transmission coordination reforms. As noted above, we find that these reforms are necessary to identify more efficient or cost-effective transmission facilities than what individual transmission planning regions may identify, thereby helping to ensure that jurisdictional rates for transmission service are just and reasonable and not unduly discriminatory or preferential. Accordingly, it follows that such common OATT language must be filed with the Commission. Furthermore, we fail to see how this is changed by the Commission allowing, as an alternative, public utility transmission providers to reflect the interregional transmission coordination procedures in an agreement filed with the Commission.

225. Moreover, whether or not such agreements were contemplated in the *Prior Notice Order,* we find that the *Prior Notice Order* does not prescribe the entire universe of filings that the Commission will require to be filed. To so limit the universe of such agreements would impede the Commission's statutory duty to ensure that the rates, terms, and conditions of jurisdictional service are just and reasonable and not unduly discriminatory or preferential. In the *Prior Notice Order,* the Commission made an effort to bring certainty to a number of jurisdictional issues surrounding certain agreements. Among other things, the *Prior Notice Order* stated that ''the utility industry remains unclear as to whether various types of agreements need to be filed for Commission review because of the uncertain jurisdictional status of particular types of agreements.'' [289] It should be noted that the Commission did not represent that the agreements it addressed in the *Prior Notice Order* were, or would be, the only agreements that are subject to the Commission's jurisdiction.[290]

[286] Ad Hoc Coalition of Southeastern Utilities at 63 (citing generally *Prior Notice Order,* 64 FERC ¶ 61,139, App. at 11.)

[287] Bonneville Power at 32–34 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 478, 481).

[288] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 475.

[289] *Prior Notice Order,* 64 FERC ¶ 61,139 at 61,977.

[290] In the appendix to the *Prior Notice Order,* the Commission provided ''a brief analysis of the various types of agreements identified by the participants in this proceeding * * *. [T]his analysis is general in nature and is intended to be illustrative of the Commission's current thinking on

226. Ad Hoc Coalition of Southeastern Utilities overstates the *Prior Notice Order's* discussion when it contends that the *Prior Notice Order's* remedy for late-filed agreements (i.e., time-value refunds) shows the questionable jurisdictional nature of interregional transmission coordination agreements because the remedy would not apply. We stated: ''If a utility files an otherwise just and reasonable cost-based rate after the new service has commenced, we will require the utility to refund to its customers the time value of the revenues collected * * * for the entire period that the rate was collected without Commission authorization * * *. We will implement a similar remedy for the unauthorized late filing of market-based rates.'' [291] We note that this discussion focuses on rate filings (whether market-based or cost-based). However, there are other types of documents that the Commission requires to be filed that govern the terms and conditions of jurisdictional transmission service. For example, many *pro forma* OATT provisions deal with terms and conditions rather than strictly with rates. And, as discussed herein, we find that interregional transmission coordination issues have a direct and concrete impact on jurisdictional rates and, consequently, interregional transmission coordination agreements must also be filed.

227. We clarify for Bonneville Power that Order No. 1000's interregional transmission coordination reforms are not intended to preempt the statutes governing Bonneville Power. However, to the extent that any of the interregional transmission coordination efforts in which Bonneville Power participates does have the effect of interfering with Bonneville Power's statutory duties, it may bring those concerns to the Commission's attention.

g. Other Legal Issues Related to Regional Transmission Planning Requirements

i. Requests for Rehearing and Clarification

228. APPA asserts that public power systems will likely be unable to participate in regional transmission planning processes without specific assurances that their legal obligations and concerns will be accommodated in regional transmission planning processes. In particular, APPA is concerned that public power systems may lose their tax-exempt status if transmission facilities are found to be used for private activity rather than public activity. APPA argues that Order Nos. 888 and 890 acknowledged the importance of this issue by limiting a jurisdictional public utility's transmission obligations regarding facilities funded with local furnishing bonds, and that Congress limited the Commission authority to require non-jurisdictional transmission providers to provide comparable transmission service. APPA states that the Commission's expectation that non-public utility transmission providers will participate in regional transmission planning processes is at odds with the Commission's declining to provide assurance in Order No. 1000 of accommodations for their unique limitations, choosing instead to advise public power systems to advocate such accommodation on their own in these regional processes. APPA encourages the Commission to reaffirm the specific assurances provided to public power transmission providers in the past regarding the protection of their tax-exempt financing.

229. Arizona Cooperative and Southwest Transmission seek clarification that nothing in Order No. 1000 alters the rights of entities to submit section 206 complaints charging that a transmission plan submitted, accepted, or approved under Order No. 1000, or a subsequent cost allocation or cost recovery made under such a plan, establishes or contributes to a rate, charge, classification, rule, regulation, practice, or contract that is not just and reasonable or that is unduly discriminatory or preferential. Otherwise, they seek rehearing because the right to file a complaint and the applicable standard for such complaints and for a rate, charge, classification, rule, regulation, practice or contract is established by sections 205 and 206 of the FPA and cannot be abrogated by the Commission by rule or practice.

ii. Commission Determination

230. We recognize that Order No. 1000 may have been unclear as to whether public power entities, such as those represented by APPA, would be provided with the same assurances that they received in Order Nos. 888 and 890 as to whether the requirements of the rule would abrogate their tax-exempt status or cause them to violate a private activity bond rule. Order No. 1000 had focused on the consistency of reciprocity obligations in the three orders but did not specifically address the tax-exempt status of public power entities. To be clear, the assurances provided in Order Nos. 888 and 890 remain unchanged in Order No. 1000. Consistent with Order Nos. 888 and 890, nothing in Order No. 1000 is intended to abrogate the tax-exempt status of public power entities or otherwise cause such entities to violate a private activity bond rule for purposes of section 141 of title 26 of the Internal Revenue Code.

231. In response to Arizona Cooperative and Southwest Transmission, we clarify that nothing in Order No. 1000 modifies any right to file a section 206 complaint. In so clarifying, we make the following observations. We note that Order No. 1000 does not require the filing of a regional transmission plan for Commission approval. Nonetheless, entities may file a complaint regarding the implementation of the process itself. We have entertained such complaints in similar circumstances.[292] For example, a party might argue in a section 206 complaint that the public utility transmission providers in a given region did not follow their Commission-approved Order No. 1000-compliant regional transmission process in selecting facilities in their regional transmission plan for purposes of cost allocation. Of course, under section 206, the complainant bears the burden of proof to demonstrate that the process was unjust and unreasonable and that its proposed remedy is just and reasonable. We also note that a primary purpose of Order No. 1000 is to establish a Commission-approved open and transparent regional transmission planning process that includes cost allocation determinations based on a cost allocation method that is also Commission-approved.[293]

2. Regional Transmission Planning Requirements

a. Final Rule

232. Order No. 1000 required each public utility transmission provider to participate in a regional transmission planning process that produces a regional transmission plan that complies with seven of the nine transmission planning principles of

these subjects.'' *Prior Notice Order,* 64 FERC ¶ 61,139 at 61,989. The specific types of agreements discussed in the appendix to the *Prior Notice Order* include: (1) Contribution in aid of construction agreements; (2) Qualifying Facility agreements; (3) exchanges; (4) borderline agreements; and (5) *de minimis* agreements. *Id.* at 61,989–96.

[291] *Id.* at 61,979–80.

[292] *See, e.g., Transmission Technology Solutions, LLC and Western Grid Development, LLC* v. *California Indep. Sys. Operator Corp.,* 135 FERC ¶ 61,077 (2011) (*Transmission Technology Solutions*).

[293] *See, e.g., Transmission Technology Solutions,* 135 FERC ¶ 61,077 at P 122 (''Contrary to Complainants' arguments, CAISO submitted evidence to demonstrate that its decision-making process reflected objective analysis; was consistent with the CAISO Tariff; and was based on approving the most prudent and cost-effective long-term projects that maintain reliability for the region.'').

Order No. 890.[294] Order No. 1000 required public utility transmission providers to evaluate, through this regional transmission planning process and in consultation with stakeholders, alternative transmission solutions that might meet the needs of the transmission planning region more efficiently or cost-effectively than solutions identified by individual public utility transmission providers in their local transmission planning process. This could include transmission facilities needed to meet reliability requirements, address economic considerations, or meet transmission needs driven by Public Policy Requirements.[295] When evaluating the merits of such alternative transmission solutions, the Commission also directed public utility transmission providers in the transmission planning region to consider proposed non-transmission alternatives on a comparable basis.[296] In addition, Order No. 1000 provided public utility transmission providers in each transmission planning region the flexibility to develop, in consultation with stakeholders, procedures by which the public utility transmission providers in the region identify and evaluate the set of potential solutions that may meet the region's needs more efficiently or cost-effectively.

233. The Commission clarified that for purposes of Order No. 1000, a transmission planning region is one in which public utility transmission providers, in consultation with stakeholders and affected states, have joined for purposes of satisfying the requirements of Order No. 1000, including among other purposes to develop a regional transmission plan.[297] The Commission explained that the scope of a transmission planning region should be governed by the integrated nature of the regional power grid and the particular reliability and resource issues affecting individual regions.[298] While the Commission declined to prescribe the geographic scope of any transmission planning region, the Commission nevertheless clarified that an individual public utility transmission provider cannot, by itself, satisfy the regional transmission planning requirements of either Order No. 890 or Order No. 1000.[299] The Commission also noted that every public utility transmission provider has already included itself in a region for purposes of complying with Order No. 890's regional participation principle, and encouraged public utility transmission providers to look to existing regional processes for guidance on compliance in formulating transmission planning regions.[300]

234. Further, Order No. 1000 declined to require merchant transmission developers to participate in a regional transmission planning process, because they assume all financial risk for developing and constructing their transmission facilities, and therefore, it is unnecessary to require such developers to participate in a regional transmission planning process for purposes of identifying the beneficiaries of their transmission facilities so that they can avail themselves of regional cost allocation.[301] However, Order No. 1000 acknowledged that a transmission facility proposed or developed by a merchant transmission developer has broader impacts than simply cost recovery. Therefore, Order No. 1000 concluded that it is necessary for a merchant transmission developer to provide adequate information and data to allow public utility transmission providers in the transmission planning region to assess the potential reliability and operational impacts of the merchant transmission developer's proposed transmission facilities on other systems in the region.[302]

b. Requests for Rehearing and Clarification

235. Petitioners raise a number of arguments with respect to the regional transmission planning process, which address such topics as whether public utility transmission providers were given too much flexibility, the definition of a ''transmission planning region,'' the participation of non-public utility transmission providers in regional transmission planning processes, compliance with Order No. 890 transmission planning principles, whether there needs to be a post-plan process, the role of state regulators in the regional transmission planning process, Order No. 1000's treatment of merchant transmission projects, what constitutes ''new'' transmission facilities for purposes of Order No. 1000, and other issues.

236. Some petitioners are concerned that the Order No. 1000 does not set out the regional transmission planning requirements in sufficient detail. Illinois Commerce Commission contends that the Commission erred in providing too much flexibility in the regional planning process, and that now is the time for the Commission to provide guidance to the industry that will reduce business uncertainty and increase process efficiency. WIRES urges the Commission to assist the industry with new standard procedures for regional planning, including criteria for evaluating both major backbone projects and transmission upgrades that have a relatively short planning and construction cycle and that can be adapted to fill economic or reliability needs as they arise in the ordinary course of system operations. Regarding Order No. 1000's statement that ''public utility transmission providers *explain* in their compliance filings how they will determine which facilities evaluated in their local and regional planning processes will be subject to the requirements of this Final Rule'' (emphasis added), Western Independent Transmission Group requests that transmission providers should not only simply ''explain'' how they will determine which facilities to evaluate, but also should be required to justify those determinations in their compliance filings.

237. PPL Companies are concerned with Order No. 1000's mandate to participate in a regional transmission planning process, arguing that such a mandate forces utilities in non-RTO regions to join an RTO or RTO-like process. PPL Companies claim that because this mandate may put certain entities at odds with their state commissions, the Commission should clarify that RTO membership remains voluntary, as does participation in regional transmission planning.

238. Others are concerned that Order No. 1000's regional transmission planning reforms may allow public utility transmission providers to discriminate against other entities. Transmission Access Policy Study Group claims that Order No. 1000 enhances the ability of public utility transmission providers in non-RTO regions to benefit their generation function by giving them the right to make decisions as to which upgrades go into the regional transmission plan for purposes of cost allocation, while transmission dependent utilities and non-jurisdictional entities are only offered the opportunity to provide input into the planning process. It points to the *RTG Policy Statement,* which it

[294] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at PP 146, 151 & n.141 (the regional participation and cost allocation principles were not included because they are the subject of specific reforms in Order No. 1000).

[295] *Id.* P 148.

[296] *Id.*

[297] *Id.* P 160.

[298] *Id.* (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 527).

[299] *Id.*

[300] *Id.*

[301] *Id.* P 163.

[302] *Id.* P 164.

states provides for fair and nondiscriminatory governance and decision-making procedures and which states that transmission dependent utilities must be protected.[303] If a non-RTO region does not provide balanced decision-making, Transmission Access Policy Study Group argues that there should be consequences, such as more scrutiny with respect to transmission rates and regional cost allocation methods. PPL Companies seek clarification that the Commission will review the voting rules and structures of regional and interregional groups to ensure that the effect of such structures on small utilities is not unjust, unreasonable or unduly discriminatory.

239. Transmission Dependent Utility Systems further argue the Commission should clarify that more efficient and cost-effective solutions to the effects of loop flow are among the things to be considered in regional planning and interregional coordination processes. Transmission Dependent Utility Systems state that although Order No. 1000 discusses loop flows in the context of cost allocation, it does not address the issue in the context of regional planning or interregional coordination.

240. Several petitioners seek clarity as to what the Commission means by a ''transmission planning region.'' [304] Energy Future Coalition Group asserts that the Commission must set minimum standards for defining transmission planning regions; otherwise, such regions may be defined in a way that is irrational and unworkable, thus hindering the transmission development that Order No. 1000 is meant to promote. It suggests the following: All transmission providers in the region must be within the same interconnection; participants in the region must be electrically contiguous; the region must have sufficient existing internal electricity generation and consumption to justify the planning of high voltage transmission facilities within it; and the region must be an integrated electric system for which transmission planning within the region can be accomplished consistent with engineering principles and common sense. It also suggests that the Commission specify that use of the regions approved for purposes of Attachment K coordination of transmission plans would be presumptively acceptable.

241. Ad Hoc Coalition of Southeastern Utilities commends the Commission for what it characterizes as a reaffirmation of existing regions. However, it asserts that if the Commission changes course and finds that planning regions in the Southeast are different from current regions, such a finding would be counter to Order No. 890 precedent. It also asserts that it would violate FPA section 202(a) because affected transmission owners and providers have not agreed to engage in transmission coordination based on a different configuration of a region. Southern Companies raise similar arguments, noting that it is commencing its compliance requirements with the understanding that the SERTP is an appropriate region under Order No. 1000.

242. PPL Companies state that the geographic scope requirement poses difficulties outside of an RTO. For example, they state that if Louisville Gas & Electric and Kentucky Utilities prefer to have a Kentucky-only planning group, it is unclear from Order No. 1000 whether such a region would be sufficient for regional planning purposes. PPL Companies further claim that regional transmission planning requirements raise practical concerns for entities outside of RTOs, particularly those in regions with non-public utility transmission providers, which have the discretion, not a mandate, to comply. PPL Companies thus seek clarification that a region can be comprised of a single system or single state where a broader scope is either difficult or impossible to attain.

243. MISO Northeast seeks clarification that an RTO/ISO may have more than one transmission planning region for purposes of developing regional transmission plans, noting that there are three distinct subregions in MISO. MISO Northeast states that while the Commission does not require any changes to existing regions, limiting the number of transmission planning regions in an RTO/ISO to one would have the effect of prescribing the geographic scope of a transmission planning region, which the Commission said it would not do in Order No. 1000.

244. Several petitioners take issue with Commission's statement in Order No. 1000 that, ''if a non-public utility transmission provider makes the choice to become part of the transmission planning region and it is determined by the transmission planning process to be a beneficiary of certain transmission facilities selected in the regional transmission plan for purposes of cost allocation, that non-public utility transmission provider is responsible for the costs associated with such benefits.'' [305]

245. Large Public Power Council contends that unless non-public utility transmission providers vote on which proposed transmission projects should be selected in the regional transmission plan for purposes of cost allocation, the Commission should allow non-public utility transmission providers to participate in all aspects of regional transmission planning without being allocated costs pursuant to the regional cost allocation method. Large Public Power Council argues that to do otherwise will substantially disrupt existing planning processes by discouraging non-public utility transmission providers from participating out of concern that they will be allocated costs, detrimentally affecting system efficiency, cost, and reliability.

246. MEAG Power contends that it would be problematic for it to enter into an open-ended commitment to pay costs that are allocated per a regional plan before the regional planning and cost allocation protocols have been developed and determined. Moreover, MEAG Power states that this will deter it from continuing to participate in the current SERTP planning effort on a voluntary basis if in doing so it would be bound to an unknown amount of allocated transmission costs. MEAG Power requests clarification that its choice to continue to participate in SERTP does not bind it to a cost allocation result under Order No. 1000 Otherwise, it states it will be compelled by its Board's policy to withdraw from SERTP as well as SIRPP before the provisions of Order No. 1000 take full effect.

247. Transmission Dependent Utility Systems request that the Commission clarify or grant rehearing to specify that those stakeholders who have not meaningfully participated in the regional planning or interregional coordination, the development of regional and interregional cost allocation methods, or in the determination of beneficiaries, will have no costs for such projects allocated to them. Transmission Dependent Utility Systems argue this clarification will ensure participation of load-serving customers and is consistent with Cost Allocation Principle 2.

248. Sacramento Municipal Utility District states that it participates in both

[303] Transmission Access Policy Study Group at 9 (citing *RTG Policy Statement,* 58 Fed. Reg. 41,626 (Aug. 5, 1993), FERC Stats. & Regs. ¶ 30,976 (1993); *Southwest Regional Transmission Ass'n,* 69 FERC ¶ 61,100, at 61,400–02 (1994); *PacifiCorp,* 69 FERC ¶ 61,099, at 61,382, n.70 (1994)).

[304] *See, e.g.,* Ad Hoc Coalition of Southeastern Utilities; Energy Future Coalition Group; MISO Northeast; PPL Companies; and Southern Companies.

[305] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 629.

the California Transmission Planning Group and the WestConnect planning processes, but would have little incentive to participate in either if doing so would expose it to costs for transmission over which it does not take any service and could result in duplicative charges.

249. Bonneville Power seeks clarification that it may independently decide, using an open and transparent process consistent with its statutory authorities, whether it will receive the benefits of, and pay for, a transmission project. It requests clarification that the regional planning process determination would not be binding on it, but that, instead, it and transmission developers could use the cost allocation analysis as input to their negotiations and other required statutory processes. Bonneville Power argues that this clarification is appropriate because its governing statutes do not permit it to participate in mandatory cost allocation, explaining that its Administrator must determine its cost allocation responsibilities and cannot delegate them to the regional planning process.[306] Bonneville Power argues that it also must retain the right to determine whether or not to commit funds to a project until conclusion of a review of a project under the National Environmental Policy Act. In the alternative, Bonneville Power requests rehearing, arguing that the Commission failed to adequately consider and address its comments addressing Bonneville Power's statutory authorities related to mandatory cost allocation.

250. With respect to Order No. 1000's discussion of compliance with Order No. 890 transmission planning principles and related issues, Ad Hoc Coalition of Southeastern Utilities argues that the Southeast transmission planning regions already comply with Order No. 890's planning principles. Ad Hoc Coalition of Southeastern Utilities asserts that Order No. 890 and the subsequent compliance orders make it clear that the nine planning principles apply to regional planning processes. However, it asserts that certain statements in Order No. 1000, such as the statement that some regions are not exchanging sufficient data, imply that all or some of the nine planning principles do not apply under Order No. 890 to the existing regional planning processes.[307] If the Commission assumes or concludes that utilities in the Southeast are not exchanging sufficient information, then Ad Hoc Coalition of Southeastern Utilities contends that such an assumption or conclusion would be in error and not supported by substantial evidence.

251. With regard to the openness and transparency transmission planning principles, Transmission Dependent Utility Systems want the Commission to clarify that information cannot be withheld from load-serving entities based on common rationales offered by transmission owners, such as claims of discrimination against non-load-serving entity customers, violation of tariff confidentiality provisions, or violation of the Commission's Standards of Conduct. They argue that if these concerns are legitimate, they can be adequately addressed by confidentiality agreements or through other appropriate means. Transmission Dependent Utility Systems also want the Commission to confirm that such disclosure will not be deemed a violation of the Standards of Conduct.

252. With respect to the requirement that public utility transmission providers develop a regional transmission plan, Illinois Commerce Commission argues that the Commission erred in not requiring each transmission provider to file its regional transmission plan (as well as associated cost allocations), contending that the regional and interregional stakeholder processes that Order No. 1000 requires are not sufficient to ensure notice to the public and an opportunity to be heard. Illinois Commerce Commission states that the failure to establish a process for Commission review of regional transmission plans and associated cost allocations burdens ratepayers and exacerbates the problem associated with delegating authority to transmission providers.[308]

253. Transmission Access Policy Study Group argues that Order No. 1000 should have required a timely post-plan process to ensure that the plan is acted upon, and argues that if a transmission developer has made a commitment to construct facilities, then it should not have the option to abandon the project, thus leaving others that counted on the upgrade responsible for the costs. It contends that the steps Order No. 1000 did take, such as Web site posting requirements and the reliability protections addressed in the context of Order No. 1000's nonincumbent reforms, are inadequate. Additionally, Transmission Access Policy Study Group argues that Order No. 1000 should have made clear that the Web site posting requirement it did require must be made on a timely basis, such as a specified time after the regional transmission plan is posted.

254. Some state regulators raise concerns about the role they are intended to play in the regional transmission planning process.[309] NARUC argues that, while prior Commission orders and the DOE-funded interconnectionwide planning processes properly recognize the essential role of state regulators, Order No. 1000 improperly lumps state regulators with all other stakeholders. Illinois Commerce Commission also points out that Order No. 1000 does not require transmission providers to establish any unique role or provide any special weight in the process for state regulators. Wisconsin PSC asserts that there is no rational basis for the casual and undefined potential role that Order No. 1000 implies that states would have in the regional and interregional transmission planning processes. It asserts that states and state commissions are different from other stakeholders in materially important ways, such as their authority to authorize utilities to build and the ability to collect an allocated share of the cost of transmission facilities. It also claims that this treatment of the states is at odds with Order No. 890's express emphasis that ''planning must be coordinated with state regulators * * *''.[310] Given this, Wisconsin PSC suggests the following changes to help enhance state participation: (1) More focus on reducing planning delays in a project's preconstruction phase by coordinating with state regulators; (2) minimizing overlap between state and regional transmission planning procedures relative to evaluation of project need or sponsor qualification; and (3) where feasible, required compliance with applicable state laws by a transmission developer before any transmission line is selected for eligibility for regional cost sharing. North Carolina Agencies state that the Commission should recognize the unique and indispensible role that state regulatory authorities play, rather than demoting them to one of many stakeholders, as suggested in Order No. 1000.

255. Further, Illinois Commerce Commission contends that the

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[306] Bonneville Power at 13–15 (citing Northwest Power Act, 16 U.S.C. § 839f(b) (2006); Transmission System Act, 16 U.S.C. § 838b (2006); *Pacific Northwest Generating Coop.* v. *DOE, Bonneville Power Admin.,* 580 F.3d 792, 823 (9th Cir. 2009)).

[307] Ad Hoc Coalition of Southeastern Utilities at 48 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at PP 151–52).

[308] As noted above, Illinois Commerce Commission also believes that Order No. 1000 provides too much flexibility to transmission providers.

[309] *See, e.g.,* NARUC; Florida PSC; Illinois Commerce Commission; and Wisconsin PSC.

[310] Wisconsin PSC at 9 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 574 (2007)).

Commission failed to recognize that state regulators may be limited in their ability to actively engage in transmission planning processes given the prohibition against pre-judging cases that may subsequently come before them for siting, certification, or rate recovery. Illinois Commerce Commission suggests that Commission attendance in a meeting of the states to discuss this issue may be useful to reconcile the Commission's expectations and the practical realities borne by state regulators in this regard.

256. Florida PSC states that it is unclear how the Order No. 1000 transmission planning process overlay will interact and coexist with existing planning processes. Florida PSC also asserts that participating in the planning processes and monitoring neighboring interregional agreements would require additional state commission resources during a time of constrained state budgets. Illinois Commerce Commission likewise contends that the level of participation the Commission is encouraging is beyond most states' current capabilities. It states that the Commission must go beyond Order No. 890 initiatives to facilitate enhanced participation by state authorities in regional and interregional planning processes. Illinois Commerce Commission also seeks clarification that, where regional state committees have been formed, it will be that committee (with Commission review) that decides on its budget for participation in the planning process, and such budget shall not be subject to veto by the transmission provider or any stakeholder group.

257. Some petitioners seek rehearing or clarification of Order No. 1000's discussion of the role of merchant transmission developers in the regional transmission planning process.[311] APPA asks that the Commission reconsider its decision to allow merchant developers merely to provide information to transmission planners and instead require merchant transmission developers to participate fully in regional and interregional transmission planning processes. APPA argues that requiring such developers to participate in regional and interregional planning processes will give transmission planners the opportunity to evaluate all projects side-by-side and then develop the set of projects that will best serve the needs of all loads in a region, while presenting the best economics and minimizing adverse impacts on the environment.

258. National Rural Electric Coops seek clarification that Order No. 1000 does not create a special class of public utilities, i.e., merchant transmission developers, who are excused from obligations imposed on other public utility transmission providers. National Rural Electric Coops argue that the creation of a preferred class distinguished solely by their method of cost recovery does not square with the purpose of Order No. 1000 to ensure that all public utility transmission providers be treated comparably in the transmission planning process. They contend that the method of cost recovery is not a valid reason for excusing public utility merchant developers from the regional planning requirements generally applicable to public utility transmission providers.

259. Transmission Dependent Utility Systems seek rehearing of the determination that merchant transmission developers may opt out of participation in regional transmission planning processes if they assume all financial risk. Transmission Dependent Utility Systems argue that financial arrangements have no bearing on the ability of affected load-serving entities to reliably and economically serve their native loads, that the failure to mandate merchant participation in regional transmission planning therefore conflicts with FPA section 217(b)(4), and that the internalization of risk by a merchant developer cannot justify excusing it from compliance with other planning obligations. They add that requiring merchant developers only to share information with public utility transmission providers fails to ensure that load-serving transmission customers will be able to obtain information about proposed merchant projects, evaluate their effects, and provide input regarding their development. Transmission Dependent Utility Systems seek clarification that if a merchant developer does not fully participate in a regional transmission planning process, it should be obligated to internalize the costs of any adverse reliability effects on the grid posed by its project or any need for upgrades caused by a change in flows, adding that the failure to require merchant developers to internalize all related costs of their transmission projects would violate cost causation principles by forcing transmission customers to pay for the costs of upgrades caused, but not paid for, by merchant transmission developers.

260. Petitioners raise concerns about Order No. 1000's conclusion that public utility transmission providers could apply flexible criteria when determining which transmission projects are in the regional transmission plan. PSEG Companies argue that the Commission introduced vague criteria into the planning process that will result in an opaque and confusing, rather than a formulaic, approach.[312] They claim that an opaque approach will allow transmission providers to unofficially represent policymaking bodies and impose their costs on customers, who must pay for unneeded projects.

261. Finally, some petitioners request guidance on what constitutes a ''new'' transmission facility for purposes of Order No. 1000. Western Independent Transmission Group seeks clarification of the Commission's statement that Order No. 1000 applies to new transmission facilities. It states that Order No. 1000 does not provide sufficient guidance as to how transmission providers should define evaluation and reevaluation for purposes of determining what facilities are subject to Order No. 1000. It contends that, in the absence of Commission guidance, transmission providers will have excessive discretion to determine which facilities are subject to Order No. 1000. Western Independent Transmission Group seeks clarification regarding the extent of transmission planning entities' discretion and Commission guidance as to how such discretion should be exercised without restricting independent developers' access to the grid.

262. LS Power requests that the Commission clarify that all projects that are approved on or after the compliance date shall be subject to Order No. 1000, regardless of the status of the planning cycle. It explains that such a requirement would not burden the regional planning process as the transmission planning entity has ample warning regarding the requirement and can tailor its planning process to incorporate Order No. 1000 for all projects not yet approved as of the compliance date.

c. Commission Determination

263. Order No. 1000's regional transmission planning reforms are intended to ensure that there is an open and transparent regional transmission planning process that complies with Order No. 890's transmission planning principles and produces a regional transmission plan. There, we stated that

[311] *See, e.g.,* APPA; National Rural Electric Coops; and Transmission Dependent Utility Systems.

[312] PSEG Companies at 50 (citing *PJM Interconnection, L.L.C.,* 119 FERC ¶ 61,265 at P 24 (2007) (directing PJM to file a formulaic approach with respect to planning for economic transmission projects)).

such transmission planning will expand opportunities for more efficient and cost-effective transmission solutions for public utility transmission providers and stakeholders, which, in turn, will help ensure that the rates, terms, and conditions of Commission-jurisdictional services are just and reasonable and not unduly discriminatory or preferential.[313]

264. For the most part, petitioners do not argue against the soundness of Order No. 1000's basic regional transmission planning requirements although, as discussed above, some petitioners question the need for these reforms as applied to their specific regions of the country,[314] while some assert that the Commission lacks the legal authority to undertake these reforms, as discussed earlier in this section.[315] However, most of the petitioners' requests as to the actual regional transmission planning requirements go to specific issues, such as the flexibility afforded in Order No. 1000 to public utility transmission providers, the definition of a transmission planning region, the participation of non-public utilities and the role of state regulators in the regional transmission planning process, compliance with certain transmission planning principles, the treatment of merchant transmission developers, and the definition of ''new'' transmission facilities under Order No. 1000.

265. In this section, we affirm Order No. 1000's regional transmission planning reforms. We also provide clarifications on many of the issues raised by petitioners, including an issue that generated a number of requests for rehearing and clarification, namely, the participation of non-public utility transmission providers in the regional transmission planning process. We believe the discussion herein will assist public utility transmission providers, in consultation with stakeholders, in developing their Order No. 1000 compliance filings by providing more clarity as to what the Commission's requirements are with respect to Order No. 1000's regional transmission planning reforms.

266. Some petitioners, such as Illinois Commerce Commission, assert that Order No. 1000's regional transmission planning reforms provide too much flexibility to public utility transmission providers. We disagree. Rather, we believe that Order No. 1000 sets forth an approach that balances the need to ensure that specified regional transmission planning requirements are satisfied with our belief that the various regions of the country differ significantly in resources, industry organization, market design, and other ways so that a one-size-fits-all approach to regional transmission planning would not be appropriate. Specifically, Order No. 1000 requires public utility transmission providers to develop a regional transmission planning process that complies with the Order No. 890 transmission planning principles and that produces a regional transmission plan. Within these parameters, public utility transmission providers, in consultation with stakeholders, have the flexibility to ensure that their respective regional transmission planning process is designed to accommodate the unique needs of that particular region. We will then evaluate each of the Order No. 1000 compliance filings to ensure that they satisfy these requirements.

267. For the same reasons, we decline to adopt standard procedures in the regional transmission planning process for evaluating backbone transmission facilities or for addressing transmission upgrades that have a short planning and construction cycle and that can be adapted to fill economic or reliability needs as they arise in the ordinary course of system operations, as suggested by WIRES. As the Commission found in Order No. 1000, each public utility transmission provider is required to amend its OATT to describe a transparent and not unduly discriminatory process for evaluating whether to select a proposed transmission facility in the regional transmission plan for purposes of cost allocation. This process must comply with the Order No. 890 transmission planning principles, ensuring transparency and the opportunity for meaningful stakeholder input. The evaluation process must culminate in a determination that is sufficiently detailed for stakeholders to understand why a particular transmission facility was selected or not selected in the regional transmission plan for purposes of cost allocation.[316] Accordingly, we do not find that standardized procedures such as those suggested by WIRES are necessary or appropriate. Moreover, by requiring an open and transparent transmission planning process that produces a regional transmission plan, Order No. 1000 will provide the Commission and interested parties with a record that we believe will be able to highlight whether public utility transmission providers are engaging in undue discrimination against others, such as transmission-dependent utilities and non-jurisdictional entities.

268. As discussed in greater detail in the section of Order No. 1000 addressing nonincumbent reforms,[317] we agree with Western Independent Transmission Group that public utility transmission providers should both explain and justify the nondiscriminatory evaluation process proposed in their compliance filings. Additionally, Commission review and approval of a not unduly discriminatory evaluation process will address Transmission Access Policy Study Group's concern that Order No. 1000's regional transmission planning reforms may empower public utility transmission providers at the expense of other stakeholders, as well as its concern that the regional transmission planning governance process should be fair and not unduly discriminatory for all participants, including transmission dependent utilities.

269. PPL Companies assumes that a region will have formal voting rules and structures to carry out these evaluations and decide which proposed new transmission facilities are in the regional transmission plan and selected for cost allocation, and it requests that we review the voting rules and structures of each region's transmission planning process to ensure that they do not disadvantage smaller utilities. While Order No. 1000 does not necessarily require formal voting rules, we will review any rules submitted to ensure that they are fair to all participants. More important, we believe that adherence to the seven Order No. 890 transmission planning principles, as adopted in Order No. 1000, will ensure fair treatment of all regional planning participants, and we will review the process in every compliance filing, whether or not it has formal voting rules and stakeholder governance structure, for compliance with the transmission planning principles for (1) coordination, (2) openness, (3) transparency, (4) information exchange, (5) comparability, (6) dispute resolution, and (7) economic planning. If public utility transmission providers in a transmission planning region, in consultation with stakeholders, decide to establish formal stakeholder governance procedures, such as voting measures, they should include these in their Order No. 1000 compliance filings.

270. We agree with PPL Companies that RTO membership is and remains voluntary. However, regional

[313] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 146.

[314] *See* discussion *supra* at section II.B.

[315] *See* discussion *supra* at section III.A.

[316] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 328.

[317] *See id.* at section III.B.3.

transmission planning under Order No. 1000 is not voluntary for public utility transmission providers.[318] We disagree that by mandating a regional transmission planning process we are forcing utilities in non-RTO areas to join an RTO-like organization. The transmission planning function of Order No. 1000 is but one of nine essential characteristics and functions of an RTO under Order No. 2000, which include having an independent grid operator for the entire region, among other operating functions. Here, Order No. 1000's transmission planning requirements involve the consideration of whether more efficient or cost-effective alternatives to solutions identified in individual local transmission plans exist and whether they will be selected in a regional transmission plan for purposes of cost allocation. As discussed in Order No. 1000 and here, we find that such transmission planning activities are wholly within the Commission's statutory authority, and that such reforms are necessary to implement at this time.

271. In response to Transmission Dependent Utility Systems, we do not believe that it is necessary that we require that the regional transmission planning process and interregional transmission coordination procedures specifically address loop flows. We believe that such concerns will necessarily be evaluated by the public utility transmission providers in the regional transmission planning process as they plan for the region's reliability and economic needs, as well as the transmission needs driven by Public Policy Requirements. Likewise, if loop flow affects more than one transmission planning region, these issues may be addressed as part of Order No. 1000's interregional transmission coordination.

272. With respect to questions from some petitioners concerning transmission planning regions,[319] we affirm Order No. 1000's determination that ''the scope of a transmission planning region should be governed by the integrated nature of the regional power grid and the particular reliability and resource issues affecting individual regions.'' [320] We also affirm Order No. 1000's determination that the Commission will not prescribe the size or scope of a transmission planning region in a generic proceeding except to provide that a single public utility transmission provider by itself may not be a transmission planning region, consistent with Order No. 890.[321] We find that Order No. 1000 appropriately provided flexibility in this regard, and that this flexibility will permit public utility transmission providers and others the opportunity to form or join a transmission planning region that best meets their needs and the needs of their transmission customers.

273. In response to Southern Companies and Ad Hoc Coalition of Southeastern Utilities, we reiterate that public utility transmission providers may look to the transmission planning regions that were accepted by the Commission in the Order No. 890 compliance phase in forming a transmission planning region for purposes of Order No. 1000.

274. We appreciate petitioners' concerns about Order No. 1000's expectations regarding the participation of non-public utility transmission providers in the regional transmission planning process. After reviewing the requests for rehearing and clarification on this topic, we provide additional clarifications to the discussion in Order No. 1000 regarding the participation of non-public utility transmission providers in the regional transmission planning process.

275. As discussed more fully below, public utility transmission providers in each transmission planning region must have a clear enrollment process that defines how entities, including non-public utility transmission providers, make the choice to become part of the transmission planning region.[322] In addition, each public utility transmission provider (or regional transmission planning entity acting for all of the public utility transmission providers in its transmission planning region) must include in its OATT a list of all the public utility and non-public utility transmission providers that have enrolled as transmission providers in its transmission planning region. A non-public utility transmission provider that makes the choice to become part of a transmission planning region by enrolling in that region would be subject to the regional and interregional cost allocation methods for that region.[323] Any non-public utility transmission providers that do not make the choice to become part of the transmission planning region will nevertheless be permitted to act as stakeholders in the regional transmission planning process.[324] In sum, we believe that the requirement to have a clear enrollment process for transmission providers in a transmission planning region, including non-public utility transmission providers that make the choice to join that region, along with the maintenance of a list of such enrollees, provides certainty regarding who is enrolled in a region and therefore who is a potential beneficiary that may be allocated costs.

276. In response to petitioners such as MEAG Power, we clarify that participation in the development of the regional transmission planning process and regional cost allocation method that a public utility transmission provider will submit to the Commission to comply with Order No. 1000 does not obligate a non-public utility transmission provider to choose to join the transmission planning region by enrolling and thus be eligible to be allocated costs under its regional cost allocation method. As such, a non-public utility transmission provider will not be considered to have made the choice to join a transmission planning region and thus eligible for cost allocation until it has enrolled in the transmission planning region. However, the regional transmission planning process is not required to plan for the transmission needs of such a non-public utility transmission provider that has not made the choice to join a transmission planning region. If the non-public utility transmission provider is a customer of a public utility transmission provider in the region, that public utility transmission provider must plan for that customer's needs as it would for the needs of any customer. That non-public utility transmission provider's ability to participate as a stakeholder in the regional transmission planning process should be the same as

[318] We address PPL Companies' legal arguments regarding mandatory transmission planning requirements above. *See* discussion *supra* at section III.A.1.

[319] *See, e.g.,* PPL Companies; MISO Northeast; and Energy Future Coalition Group.

[320] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 160 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 527).

[321] *Id.*

[322] While Order No. 1000 did not address issues relating to stakeholder procedures, we note that those that make the choice to become part of a transmission planning region could be provided with voting rights upon enrollment if the regional transmission planning process has a voting mechanism for selecting transmission projects in the regional transmission plan for purposes of cost allocation. *See, e.g.,* Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 at P 252 (stating that ''[w]ithin an RTO or ISO, stakeholder processes can be used to determine whether to pursue either economic or reliability upgrades and, thus, voting mechanisms such as those suggested by PSEG could be adopted if stakeholders desire.'').

[323] We note that many of the issues raised by petitioners that are addressed in this part of the order also implicate reciprocity issues. Requests for rehearing and clarification regarding Order No. 1000's conclusions regarding reciprocity are addressed in section V.B, *infra.*

[324] The term ''stakeholder'' is intended to include any party interested in the regional transmission planning process. *See* Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at n.143.

for any other similarly situated stakeholder customer.

277. While we acknowledge concerns raised by petitioners such as MEAG Power and Large Public Power Council about how non-public utility transmission providers make the choice to join a transmission planning region, we conclude that these concerns are best addressed in the first instance through participation in the development of the regional transmission planning process and cost allocation method that its neighboring public utility transmission provider(s) will rely on to comply with Order No. 1000. Each non-public utility transmission provider may decide whether or not to enroll in the region as a transmission provider as such development nears completion. Participation in the development of regional processes will not in itself make the participant subject to regional cost, absent enrollment. We encourage MEAG Power and other non-public utility transmission providers to raise their concerns with all participants in the development of the regional transmission planning process and cost allocation method as they are developing the compliance filings.[325] If non-public utility transmission providers believe that their concerns have not been adequately addressed, they may raise their concerns when the neighboring public utility transmission providers in the region submit their compliance filing to the Commission.

278. We decline to adopt Large Public Power Council's suggestion that there either be voting mechanisms in place or allow non-public utility transmission providers to participate in all aspects of regional transmission planning without being allocated costs pursuant to the regional cost allocation method. The enrollment process that we are requiring here should address these concerns in part. Additionally, as noted above, non-public utilities—including non-public utility transmission providers that also are load-serving entities or have other stakeholder interest in the regional transmission system—can still participate as stakeholders in the regional transmission planning process, even if they do not enroll in the regional transmission planning process. As stakeholders, non-public utility transmission providers will have an opportunity to express their views and concerns as part of the process.

279. We clarify for Bonneville Power that the Commission in Order No. 1000 did not require it, or any other non-public utility transmission provider, to enroll or otherwise participate in a regional transmission planning process. As discussed above, it will be Bonneville Power's decision whether or not to enroll as a transmission provider in a transmission planning region and become subject to that region's cost allocation method. Additionally, with respect to Bonneville Power's concerns regarding its perceived conflict between its statutory authorities and Order No. 1000's cost allocation requirements, we believe that any such perceived conflict is best addressed in the first instance through participation in the development of the regional transmission planning process and cost allocation method that its neighboring public utilities will rely on to comply with Order No. 1000.

280. We reaffirm Order No. 1000's statement that many public utility transmission providers may need to make only modest changes to their regional transmission planning processes to comply with Order No. 1000.[326] Thus, if public utility transmission providers believe that the regional transmission planning process in which they participate already complies with the Order No. 890 transmission planning principles, such as Ad Hoc Coalition of Southeastern Utilities' statement that existing regional processes in the Southeast are in compliance with the data exchange transmission planning principle, they should make the case for such assertions in their Order No. 1000 compliance filings.

281. In response to Transmission Dependent Utility Systems, we reiterate our determination in Order No. 890 that public utility transmission providers should provide sufficient information to ''enable customers, other stakeholders, or an independent third party to replicate the results of planning studies and thereby reduce the incidence of after-the-fact disputes regarding whether planning has been conducted in an unduly discriminatory fashion.'' [327] Thus, as we stated in Order No. 890 and subsequent orders on compliance, public utility transmission providers should provide the basic methodology, criteria, and processes used to develop transmission plans sufficient for stakeholders to be able to replicate its transmission plans, and describe the methods it will use to disclose the criteria, data, and assumptions that underlie its transmission system plans. The information should be of sufficient detail to allow a customer to replicate the results of the planning studies.[328] Additionally, in discussing the openness principle in Order No. 890, the Commission required that ''transmission providers, in consultation with affected parties, develop mechanisms, such as confidentiality agreements and password-protected access to information, in order to manage confidentiality and CEII concerns.'' [329] Subject to our review of public utility transmission providers' compliance filings, we believe that these basic requirements should permit stakeholders to access and review information that is relevant to transmission planning, while at the same time protecting information that is commercially sensitive or that is otherwise considered confidential under Commission regulations.[330]

282. Regarding Transmission Dependent Utility Systems' request that the Commission confirm that information disclosure will not be deemed a violation of the Standards of Conduct, we reiterate our determinations on the transparency principle in Order No. 890, where we addressed similar concerns about the Standards of Conduct. There, we stated that the ''simultaneous disclosure of transmission planning information can alleviate * * * Standards of Conduct

[325] *See, e.g.,* Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 117 (''[N]on-jurisdictional entities, unlike public utilities, may choose to join a regional transmission planning process and, to the extent they choose to do so, they may advocate for those processes to accommodate their unique limitations and requirements.'').

[326] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at n.142 (''[E]xisting regional transmission planning processes that many utilities relied upon to comply with the requirements of Order No. 890 may require only modest changes to fully comply with these Final Rule requirements.'').

[327] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 471.

[328] *Id.*

[329] *Id.* P 460.

[330] The Commission has addressed the issue of access to confidential material in Order No. 890 compliance proceedings. In *Entergy Services, Inc.,* 130 FERC ¶ 61,264, at PP 55–57 (2010), for example, the Commission accepted compliance revisions proposed by the Entergy Services, Inc. (Entergy) that would permit stakeholders to be certified to obtain CEII material by following certain procedures located on Entergy's Web site and the SIRPP Web site. Further, the Commission accepted revisions that allowed stakeholders to have access to resource-specific information if it was provided in the SIRPP and was needed to participate in the SIRPP or to replicate interregional studies. The Commission also found acceptable provisions regarding processing requests for CEII data. The Commission found that while Entergy and transmission owners had broad discretion over this process, as some protestors argued, that discretion was not unbounded because Entergy, its Independent Coordinator of Transmission, and transmission owners would develop procedures to review requests for access to CEII data, and protestors could thus raise concerns during that development process. The Commission noted that any party denied access to information could raise objections through the dispute resolution process.

concerns.'' [331] Further, Order No. 890 stated that ''transmission providers should make as much transmission planning information publicly available as possible, consistent with protecting the confidentiality of customer information,'' noting that it will be necessary for market participants ''to have access to basic transmission planning information'' to consider future resource options.[332] These principles apply to the Order No. 1000 regional transmission planning process. To the extent that an interested party believes that necessary information is being unreasonably withheld for unduly discriminatory purposes, we will review on a case-by-case basis.

283. With respect to questions about Order No. 1000's discussion as to whether public utility transmission providers can use flexible criteria or bright-line metrics when determining which transmission facilities are in the regional transmission plan, we affirm that public utility transmission providers, in consultation with stakeholders, may apply either flexible criteria or bright-line metrics. As we explained in Order No. 1000, the comments in the record indicated that flexible criteria may be more appropriate than the bright-line metrics we had previously required in one earlier decision.[333] We leave it to public utility transmission providers, in consultation with stakeholders, in each transmission planning region to determine what type of criteria they will use, consistent with Order No. 1000's overarching goal of providing flexibility to meet regional needs. Thus, we clarify that we were not necessarily endorsing flexible criteria over bright-line criteria.

284. However, we reject PSEG Companies' argument that, by making this decision, the Commission will introduce opaqueness and confusion into the transmission planning process and that it will allow public utility transmission providers to unofficially represent policymaking bodies. We continue to find that there is merit in using a flexible approach because it may capture certain transmission projects that might be unnecessarily excluded with a bright-line approach. We believe that this approach is reasonable, particularly in light of the many comments that were supportive of a flexible approach. And, again, we are not mandating such an approach, and proponents of bright-line metrics can advocate for use of those metrics during the compliance process. We also find PSEG Companies' argument that this approach would allow public utility transmission providers to unofficially represent policymaking bodies to be speculative and unsupported. We therefore reject that argument. However, if PSEG Companies believe that, in a specific case, that is the case, it may file a complaint under section 206.

285. In response to Illinois Commerce Commission, we decline to establish a generic requirement in Order No. 1000 for the filing of regional transmission plans with the Commission. We believe doing so is unnecessary given the requirements of Order No. 1000, which requires public utility transmission providers to participate in a regional transmission planning process that produces a regional transmission plan and complies with Order No. 890 transmission planning principles.[334] We will evaluate compliance filings to ensure that public utility transmission providers satisfy these requirements, but we do not see a need to mandate the additional requirement of filing regional transmission plans that result from the regional transmission planning process. Our concern is with ensuring that there is an open and transparent regional transmission planning process. We are not dictating substantive outcomes of that process.[335]

286. Similarly, we do not require under Order No. 1000 that public utility transmission providers file with the Commission associated cost allocation determinations. Again, we believe that this is unnecessary under Order No. 1000. There, the Commission required public utility transmission providers to have an *ex ante* cost allocation method on file with and approved by the Commission.[336] This cost allocation method is required to explain how the costs of new transmission facilities selected in a regional transmission plan for purposes of cost allocation are to be allocated, consistent with the cost allocation principles set forth in Order No. 1000. Customers, stakeholders, and others have ''notice'' at the time the compliance filings are made, when the Commission acts on those filings, and as the open and transparent regional transmission planning process results in the selection of a transmission facility in the regional transmission plan for purposes of cost allocation. However, consistent with the regional flexibility provided in Order No. 1000, public utility transmission providers, in consultation with stakeholders, may propose OATT revisions requiring the submission of cost allocations in their Order No. 1000 compliance filings.

287. Moreover, we disagree with Illinois Commerce Commission that the Commission is delegating authority to public utility transmission providers. As discussed above, the Commission will evaluate compliance filings to ensure that they comply with Order No. 1000 and both stakeholders and the Commission have the right to initiate actions under section 206 of the FPA if they believe that, for example, a Commission-approved regional transmission planning process was not followed or if a cost allocation method was not followed or produced unjust and unreasonable results for a particular new transmission facility or class of new transmission facilities.

288. We deny Transmission Access Policy Study Group's request for a post-plan process to ensure transmission facilities are actually constructed. As we explained in Order No. 1000, the package of transmission planning and cost allocation reforms adopted is designed to increase the likelihood that transmission facilities in regional transmission plans will move from the planning stage to construction. Additionally, as acknowledged by Transmission Access Policy Study Group, a public utility transmission provider already is required to make available information regarding the status of transmission upgrades identified in transmission plans, including posting appropriate status information on its Web site.[337] To the extent that an entity has undertaken a commitment to build a transmission facility in a regional transmission plan, that information should be included in such a posting.[338] We continue to believe that this obligation, together with the other reforms found in Order No. 1000, is adequate without placing further obligations on public utility transmission providers.

289. Moreover, we are providing public utility transmission providers, in consultation with stakeholders, the flexibility to design a regional transmission planning process that meets regional needs. As part of the stakeholder process to develop the regional transmission planning processes in compliance with Order No. 1000, concerned stakeholders have the ability to participate and seek changes to those individual processes, subject to Commission review on compliance.

[331] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 476 & n.270.

[332] *Id.* P 476.

[333] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 223 (citing *PJM Interconnection, L.L.C.,* 119 FERC ¶ 61,265 (2007)).

[334] *Id.* P 146.

[335] *Id.* P 113.

[336] *Id.* PP 499–500.

[337] *Id.* P 159 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 472).

[338] *Id.* P 159 & n.155.

Additionally, we decline to prescribe specific timing parameters for the Web site posting requirement that we directed in Order No. 1000.[339] Again, if stakeholders would like to see such timing requirements as part of the Web site postings, they may seek to do so as part of the compliance process. However, the Web site postings should provide the information we require in a complete and transparent manner so that it will be fully accessible and useful to interested stakeholders such that they can see the status of various transmission facilities included in the regional transmission plan.

290. Regarding concerns about the role of state utility regulators in the regional transmission planning process, we support states' efforts to take an active role in the regional transmission planning process and encourage proposals that seek to establish a formal role for state commissions in the regional transmission planning process as well as proposals to establish cost recovery for state regulators' participation. However, for the reasons noted below, we will not require one formal method for how states will participate in the process.

291. We recognize that state utility regulators play an important and unique role in transmission planning processes, given that the states often have authority over transmission, permitting, siting, and construction, and that many state regulatory commissions require utilities to engage in integrated resource planning. We also expect that state utility regulators will play an active role in working with public utility transmission providers and other stakeholders in the Order No. 1000 compliant regional transmission planning processes.

292. That being said, the Commission finds that it would be premature in a generic proceeding to mandate any particular role for state regulators in regional transmission planning processes. Instead, we believe the best place for a state to determine the role it is to play is in the Order No. 1000 compliance process that will develop a regional transmission planning process that will be filed for Commission review. This is appropriate because individual states can be the best advocates for the role they wish to take in that process. For example, in large, multistate regions, states may seek to join a committee of state regulators that, in their view, may be a more effective vehicle for collective action than any single state could do individually. On the other hand, some states may feel that its best to have a more independent role if, for example, they believe that joining a formalized committee of state regulators may dilute their ability to participate in the regional transmission planning process. Some states may have a stronger interest in transmission planning issues than others.

293. We understand and appreciate the concerns expressed by NARUC and others that Order No. 1000 may appear to lump state utility regulators with all other stakeholders. That was not the Commission's intent. We understand that state regulators play a crucial role in transmission planning and that the role of state regulators is unique and distinctly different from the roles played by other stakeholders in transmission planning. We agree with Wisconsin PSC that the differences between state utility regulators and other stakeholders may well lead to a regional transmission planning process to treat state utility regulators differently than other stakeholders. However, for the reasons discussed next, we decline to adopt the various suggestions made by Wisconsin PSC and others to establish the same formal state commission role in every transmission planning region through a generic rulemaking proceeding, although all the regions are free to use the same formal process for state participation if they choose to do so. With respect to Illinois Commerce Commission's specific concerns about the roles state regulators might be allowed to play consistent with state law, we encourage it and other state regulators to raise such concerns during the compliance process.

294. We are aware of the wide range of views expressed by state utility commissions and others, both in rehearing petitions and previously in comments on the Proposed Rule, regarding the appropriate role of the states in regional transmission planning. Some state commissions argue for a strong role in shaping regional transmission plans, while others are concerned that their states' laws limit their ability to participate in forming plans that may come before them in regulatory proceedings. Respecting this range of views the Commission believes that each state commission, or the state commissions collectively in a region, is in the best position, in the first instance and in consultation with the transmission providers subject to their jurisdiction, to define the appropriate role for the state commissions in a particular region. This role will take into account the authorities and restrictions conferred by their own states' statutes and their own policy preferences. Thus, the Commission believes it would be inappropriate for us to define the role of all state commissions in every regional transmission planning process in a single generic proceeding, both because a state commission's authority and responsibility is established by its own state's laws—not by this Commission—and because a one-size-fits-all state role would not accommodate the wide range of views expressed by state commissions.

295. Instead, we believe the best place to determine the role any state commission plays is through the development of each region's transmission planning process. This is appropriate because individual state commissions can be the best advocates for the role they wish and are able to play in that process. We believe that, in a multistate region, the state commissions may want to establish a committee of state regulators, which may be more effective by acting collectively rather than individually. On numerous occasions, the Commission has expressed strong support for such regional state committees, and we continue to do so here. But we have not prescribed that states act though regional state committees. Some state commissions may want an independent role in regional transmission planning. Others may believe they lack authority under their states' laws to engage in planning facilities that are outside the state's borders. Finally, some states may have a stronger interest in regional transmission planning issues than others that simply have little interest in participating actively.

296. In response to Illinois Commerce Commission and Florida PSC's concerns regarding funding for state regulator participation in the regional transmission planning process, we affirm the approach taken in Order No. 1000. This approach adopted Order No. 890's requirement that public utility transmission providers propose a mechanism for recovery of planning costs in their compliance filings, including relevant cost recovery for state regulators, to the extent requested.[340] Accordingly, we encourage public utility transmission providers to engage respective state regulators regarding such provisions in their compliance filings.

297. With respect to arguments raised by petitioners concerning Order No. 1000's discussion of the role of merchant transmission developers in the regional transmission planning

[339] *Id.* P 159.

[340] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 162 (quoting Order No. 890, FERC Stats. & Regs. ¶ 31,241 at n.339 & P 586).

process, we deny rehearing. As the Commission found in Order No. 1000, because a merchant transmission developer assumes all financial risk for developing and constructing its transmission facility, it is unnecessary to require such a developer to participate in a regional transmission planning process for purposes of identifying the beneficiaries of its transmission facility that would otherwise be the basis for securing eligibility to use a regional cost allocation method or methods. However, because a merchant developer's transmission facility may nevertheless have an impact on a region's transmission network, we will continue to require a merchant transmission developer to provide adequate information and data, as explained in more detail in Order No. 1000, to allow public utility transmission providers in the transmission planning region to assess the potential reliability and operational impacts of the merchant transmission developer's proposed transmission facilities on other systems in the region. We will allow public utility transmission providers in each transmission planning region, in consultation with stakeholders, in the first instance to propose what information would be required. Public utility transmission providers should include these requirements in their filings to comply with Order No. 1000.[341]

298. In response to APPA and Transmission Dependent Utility Systems, we believe that by requiring merchant transmission developers to provide information regarding their projects, including information regarding reliability and operational impacts, public utility transmission providers and stakeholders will have sufficient information to analyze how a merchant transmission facility may impact the transmission planning region. In short, we believe that Order No. 1000's information sharing requirement balances the need for public utility transmission providers and stakeholders in transmission planning regions to know about the impacts of potential merchant transmission facilities in their regions with our view that it is unnecessary to require a specific degree of participation by merchant transmission developers in the regional transmission planning process when they are not establishing a cost-based rate base to be allocated to other beneficiaries of that facility.

299. We disagree with National Rural Electric Coops that we are establishing a ''special'' class of public utilities by requiring merchant transmission developers to comply only with an informational requirement, rather than being subject to the full panoply of requirements that will be applicable to all other public utility transmission providers. However, it should be noted that merchant transmission developers are those for which the costs of constructing the proposed transmission facilities will be recovered through negotiated rates instead of cost-based rates, so that this fact alone serves to distinguish them from other developers.[342] As noted above, merchant transmission developers are not seeking to allocate the costs associated with their merchant transmission facilities to other entities. Thus, we affirm our decision in Order No. 1000.

300. We also decline Transmission Dependent Utility Systems' request that we clarify that merchant transmission developers not participating in the regional transmission planning process should be obligated to internalize the costs of any adverse reliability effects on the grid posed by its transmission facility or any need for upgrades caused by a change in power flows. Every new facility affects the facilities around it, whether it is a merchant facility or a cost-based facility, just as the actions of one region may have positive or negative affects on neighboring regions. A generic proceeding on internalizing the costs of all new facilities, whether merchant or otherwise, is beyond the scope of Order No. 1000, and may not be suited for a blanket determination in any generic proceeding as such a determination would likely require an evaluation of the specific facts and circumstances of each particular new facility. The Commission reiterates, however, that Order No. 1000 provides that a merchant transmission developer has to pay for upgrades on neighboring systems.[343]

301. Finally, in response to those petitioners seeking clarification of what constitutes a ''new'' transmission facility, we will affirm the Commission's approach taken in Order No. 1000.[344] Order No. 1000 purposely does not define what type of evaluation or reevaluation of transmission facilities needs to occur to determine whether a previously approved facility may be subject to Order No. 1000. That is because we understand that different transmission planning regions may use different processes based on their unique needs and characteristics. We intentionally did not prescribe what such an evaluation or reevaluation must look like, and we leave it to public utility transmission providers, in consultation with stakeholders, to develop proposals addressing this issue as part of their Order No. 1000 compliance filings. If a stakeholder believes that these proposals are unduly discriminatory or preferential (e.g., they favor incumbent transmission owners to the detriment of nonincumbent transmission developers), it should raise these concerns during the development of the Order No. 1000 compliance filing and, if it is not successful at that stage, it may raise the issue before the Commission after the compliance filing is submitted. For these reasons, we decline to provide the clarifications requested by Western Independent Transmission Group and LS Power.

3. Consideration of Transmission Needs Driven by Public Policy Requirements

a. Final Rule

302. Order No. 1000 directed public utility transmission providers, in consultation with stakeholders, to amend their OATTs to describe procedures that provide for the consideration of transmission needs driven by Public Policy Requirements in the local and regional transmission planning processes.[345] By considering transmission needs driven by Public Policy Requirements, the Commission explained that it meant: (1) The identification, with stakeholders, of transmission needs driven by Public Policy Requirements; and (2) the evaluation of potential solutions, including those proposed by stakeholders, to meet those needs.[346] The Commission emphasized that it would allow local and regional flexibility in designing these procedures.[347] Additionally, to ensure that requests to include transmission needs are reviewed in a fair and non-discriminatory manner, Order No. 1000 required public utility transmission providers to post on their Web sites an explanation of which transmission needs driven by Public Policy Requirements will be evaluated for potential solutions in the local or regional transmission planning process, as well as an explanation of why other suggested transmission needs will not

[341] *Id.* P 163.

[342] *Id.* P 119.

[343] *Id.* P 165.

[344] *Id.* P 65.

[345] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 203.

[346] *Id.* PP 205–11.

[347] *Id.* P 208.

be evaluated.[348] The Commission further explained that Order No. 1000 did not establish an independent requirement to satisfy such Public Policy Requirements such that the failure of a public utility transmission provider to comply with a Public Policy Requirement established under state law would constitute a violation of its OATT.[349]

303. The Commission did not require public utility transmission providers to consider in the local and regional transmission planning processes any transmission needs that go beyond those driven by state or federal laws or regulations or to specify additional public policy principles or public policy objectives.[350] However, the Commission reiterated and clarified that Order No. 1000 does not preclude any public utility transmission provider from considering in its transmission planning process transmission needs driven by additional public policy objectives not specifically required by state or federal laws or regulations.[351]

b. Requests for Rehearing and Clarification

304. Several petitioners filed requests for rehearing and clarification regarding Order No. 1000's requirement that public utility transmission providers include in their OATTs language providing for the consideration of transmission needs driven by Public Policy Requirements. Some petitioners assert that the Commission has not spelled out with sufficient detail what is required of public utility transmission providers.[352] ELCON, AF&PA, and the Associated Industrial Groups, as well as PSEG Companies, contend that Order No. 1000 provides virtually no practical guidance as to how disparate state policies are to be reconciled. PSEG Companies also contend that the Commission's reforms may undermine competitive wholesale energy markets by driving market outcomes, explaining that predictions about generation additions and retirements that will occur in a competitive market are too speculative for a transmission provider to rely upon and, if a transmission provider were to make such judgments, then it would be a market maker or market influencer.

305. Ad Hoc Coalition of Southeastern Utilities is concerned that Order No. 1000's public policy planning requirements will be confusing and counterproductive and are likely to result in skewed decision-making. Coalition for Fair Transmission Policy argues that any construct of benefits associated with public policy-driven transmission projects would require speculation and deviate from industry norms that use models to project system conditions and dynamics for planning purposes. Long Island Power Authority argues that the process for identifying transmission needs driven by Public Policy Requirements is incomplete because it is necessary to identify what parties are subject to the Public Policy Requirements and whether such parties have a need for a transmission solution to meet those requirements.

306. Sacramento Municipal Utility District explains that current transmission planning processes take into account state renewable energy goals, adding that, to the extent that Public Policy Requirements spur development of new projects that create demand for new transmission, such projects would be incorporated into existing planning processes, even if those processes do not expressly reference the Public Policy Requirement that created the demand. Ad Hoc Coalition of Southeastern Utilities argue that Order No. 1000 fails to account for the fact that, at least in the Southeast, existing practices take into account Public Policy Requirements.

307. A number of petitioners seek rehearing or clarification on several other issues related to Order No. 1000's requirement that local and regional transmission planning processes consider transmission needs driven by Public Policy Requirements. APPA, for example, seeks clarification that the term ''Public Policy Requirements'' is intended to include duly enacted laws, ordinances, and regulations passed by units of state and local government regulating public power systems, such as city councils, utility district boards, and other governing bodies. MISO Northeast argues that the Commission should limit the definition of ''Public Policy Requirements'' to those requirements that create transmission-related benefits.

308. AEP seeks clarification that transmission providers are required to include specific, evaluated solutions to all transmission needs in the transmission plan, explaining that it is concerned that transmission providers may simply identify possible solutions to needs driven by Public Policy Requirements without including solutions that address such needs in an actionable transmission plan. As an example, AEP states that PJM is considering the ''FYI to Market'' approach, where PJM identifies projects that might respond to certain public policy needs and lets the market determine, without any PJM involvement, which projects are built.

309. Southern Companies contend that Order No. 1000's requirement that transmission needs driven by Public Policy Requirements must be considered in transmission planning processes is vague. Specifically, they claim that Order No. 1000's directive that public utility transmission providers post on their Web sites an explanation of which public policy considerations are and are not considered in the transmission planning process is impermissibly vague and overbroad. In support, Southern Companies explain that their native load has numerous federal and state legal requirements driving their load projections.

310. American Transmission seeks clarification on issues related to Order No. 1000's direction that the consideration of transmission needs driven by Public Policy Requirements applies to local, as well as regional, transmission planning processes. American Transmission seeks clarification that it is necessary and appropriate for it to amend its local planning process to include provisions for public policy-driven transmission projects.[353] It explains that it is a transmission-owning member of MISO, which has a Commission-approved regional planning process, but that it also has a Commission-approved local planning process, through which transmission projects are identified and included in the Midwest ISO MTEP process.

311. While others raise concerns about the reach of Order No. 1000 on this issue, AWEA argues that transmission planners should be required to do more than ''consider'' state and federal requirements, stating that the Commission recognized that when a transmission provider focuses only on the needs of its franchised or contract-load customers, it creates opportunities for undue discrimination. It suggests that the Commission require transmission providers to undertake scenario studies to plan and direct the build-out of the transmission system for those entities with signed interconnection agreements. It also suggests that the Commission require that scenarios account for transmission that may be necessary to accommodate

[348] *Id.* P 209.

[349] *Id.* P 213.

[350] *Id.* P 214.

[351] *Id.* P 216.

[352] *See, e.g.,* Coalition for Fair Transmission Policy; ELCON, AF&PA, and the Associated Industrial Groups; and PSEG Companies.

[353] American Transmission at 8–9 (citing what it terms as an inconsistency between paragraph 203 and footnote 185 of Order No. 1000).

individual or multiple RPS requirements or other state and federal requirements, and that transmission providers then would present these analyses to stakeholders and include recommended projects and anticipated costs under each scenario. Otherwise, it seeks clarification regarding the following: (1) That transmission providers must actively address public policy considerations within their local and regional planning processes; (2) the requirements imposed on transmission providers in meeting the requirement to consider public policy goals; and (3) that a transmission provider has an independent duty to identify needs, rather than being passive if no participant raises any concerns or needs.

312. Some petitioners raise concerns that the requirements will put transmission planners into the role of policymakers. Coalition for Fair Transmission Policy argues that, under the top-down planning permitted in Order No. 1000, the regional planning group would be placed in the position of making decisions that affect how utilities and other entities with the responsibility to meet Public Policy Requirements would meet those requirements. Coalition for Fair Transmission Policy asserts that Order No. 1000 thus authorizes submission of regional transmission planning processes that would reduce those with public policy obligations and state regulators to mere stakeholders in the regional transmission planning process. It argues that, with respect to transmission needs driven by Public Policy Requirements, regional transmission plans can be developed only through a bottom-up process. PPL Companies argue that requiring Public Policy Requirements in the transmission planning process could become a justification to unduly discriminate against ''non-renewable'' generation, which would violate the Commission's open access policies. They also assert that, to the extent public utility transmission providers are mandated to consider transmission needs driven by Public Policy Requirements in local and regional transmission planning processes, the Commission should clarify that such considerations need not, and cannot, trump the FPA's requirement that rates be just and reasonable.

313. Transmission Access Policy Study Group raises a similar concern, pointing to Order No. 1000's statement regarding the consideration of public policy goals not codified in laws and regulations. Florida PSC argues that provisions allowing transmission providers to consider additional public policy objectives not specifically required by state or federal laws or regulations should be struck. Instead, Florida PSC argues that transmission planning decisions should be based on meeting the policy requirements of state and federal law. It also states that it is unclear whether there will be enough flexibility to adjust planning decisions to respond to changes in uncodified public policies. Transmission Access Policy Study Group believes that allowing public utility transmission providers to consider such goals would allow them to substitute their own agenda for that of state and federal legislatures and regulators.

314. Transmission Access Policy Study Group raises the example that a public utility transmission provider's definition of a ''public policy'' may be influenced by the potential for incentive rate recovery or that it may define ''public policy'' to advance its own generation interests. It claims that, despite Order No. 1000's statement that public utility transmission providers always had the ability to plan for any transmission system needs that it foresees, public utility transmission providers in non-RTO regions have never before been authorized to allocate costs for transmission projects aimed at policy objectives not grounded in law or regulation.[354] It argues that planning for these goals should be grounded in terms of satisfying needs identified by load-serving entities, and requests that the Commission at least provide guidance that any plans developed based on public utility transmission providers' own public policy vision should be structured to ensure their usefulness by supporting multiple likely power supply scenarios should the original vision prove faulty. It believes this approach is more rational for integrating public policies into the planning process and will help focus planning on constructing broadly supported upgrades needed under multiple potential power supply and public policy scenarios.[355]

315. Some state electric regulatory agencies are concerned about the role they will play in the process to identify and evaluate transmission needs driven by Public Policy Requirements.[356] Illinois Commerce Commission asserts that the Commission should have clarified that, when state commissions in a region, either acting individually or via committee, decide that a unique role or special weight should be given to state authorities in the regional planning process regarding the consideration of transmission needs driven by Public Policy Requirements, then the transmission provider should be required by the Commission to defer to that decision. It maintains that by leaving the role of state authorities in the regional planning process up to the transmission providers, the Commission allows for the possibility that transmission providers can thwart the will of regionally organized state authorities. It also seeks clarification that the ''committee of regulators'' envisioned for the purpose of identifying transmission needs driven by Public Policy Requirements would not need to consist solely of personnel employed by state regulatory commissions, but could include other state authorities as well. It further seeks clarification that the engagement of such a committee will be at the discretion of the regional state committee, not at the transmission provider's discretion. It asks that the Commission clarify how its statement that authorizes use of ''a committee of state regulators'' to ''identify those transmission needs for which potential solutions will be evaluated in the transmission planning processes'' fits with the requirement that public utility transmission providers ''have in place processes that provide all stakeholders the opportunity to provide input into what they believe are transmission needs driven by Public Policy Requirements.''

316. Similarly, New York PSC requests clarification that when state regulators play a formal role in the planning process, their determinations regarding transmission needs driven by state public policies will be entitled to deference.

c. Commission Determination

317. We affirm Order No. 1000's reforms regarding the consideration of transmission needs driven by Public Policy Requirements. We recognize that Order No. 1000 could have been more clear regarding what the Commission intended, as evidenced by many of the petitioners' arguments suggesting that Order No. 1000 requires the

[354] Transmission Access Policy Study Group also cites to Order No. 1000's reference to PJM's inability to go beyond specific interconnection requests in its planning mechanism as a reason for requiring the consideration of transmission needs driven by Public Policy Requirements, claiming that this shows that the authorization to go beyond public policies embodied in state or federal laws or regulations may not be the *status quo* in some RTO regions.

[355] Transmission Access Policy Study Group at 18–19 (citing the CapX 2020 project, planning processes in MISO and New England, and California ISO's ''least regrets'' planning criteria).

[356] *See, e.g.,* Illinois Commerce Commission; and New York PSC.

consideration of Public Policy Requirements themselves, which is not the case. In this section, we clarify what the Commission intended by these reforms. We believe that these clarifications will be helpful in dispelling some of the misconceptions about this requirement that appear in many of the petitioners' requests for rehearing and clarification.

318. Order No. 1000 requires that public utility transmission providers amend their OATTs to provide for the consideration of transmission needs driven by Public Policy Requirements. Order No. 1000 did not require that Public Policy Requirements themselves be considered. This is a critical distinction. As discussed more fully below in response to requests for rehearing on this issue, we are not placing public utility transmission providers in the position of being policymakers or allowing them to substitute their public policy judgments in the place of legislators and regulators. Transmission needs driven by Public Policy Requirements, and not the Public Policy Requirements themselves, are what must be considered under Order No. 1000.

319. First, we discuss the elements of Order No. 1000's requirement regarding the consideration of transmission needs driven by Public Policy Requirements. Order No. 1000 defined ''Public Policy Requirements'' as public policy requirements established by state or federal laws and regulations.[357] Order No. 1000 explained that ''state or federal laws and regulations'' means ''enacted statutes (i.e., passed by the legislature and signed by the executive) and regulations promulgated by a relevant jurisdiction, whether within a state or at the federal level.'' [358] We grant APPA's clarification that Public Policy Requirements established by state or federal laws or regulations includes duly enacted laws or regulations passed by a local governmental entity, such as a municipal or county government. This is the intent of the word ''within'' in Order No. 1000's explanation that ''state or federal laws or regulations,'' meant ''enacted statutes * * * and regulations promulgated by a relevant jurisdiction, whether *within* a state or at the federal level.'' [359] In response to MISO Northeast, we will not revise the definition of Public Policy Requirements to limit it to those that provide transmission-related benefits. Order No. 1000 does not require the consideration of Public Policy Requirements: Rather, it requires the consideration of transmission needs driven by Public Policy Requirements. We also will not exclude any particular state or federal law or regulation from the definition of Public Policy Requirements.

320. Next, we discuss another key component of Order No. 1000's requirement, namely, the term ''consideration'' in reference to the requirement that public utility transmission providers amend their OATTs to provide for the consideration of transmission needs driven by Public Policy Requirements. By ''consideration,'' Order No. 1000 explained that this included: (1) The identification of transmission needs driven by Public Policy Requirements; and (2) the evaluation of potential solutions to meet those identified needs.[360] Order No. 1000 further explained that, with respect to the identification of transmission needs driven by Public Policy Requirements, the process must permit stakeholders with an opportunity to provide input and offer proposals regarding the transmission needs that they believe should be so identified.[361] Order No. 1000 also stated that not every suggested need will be identified such that solutions for the need will be evaluated.[362] In response to AEP, we reiterate that Order No. 1000 provides only that public utility transmission providers must *consider* transmission needs driven by Public Policy Requirements. Order No. 1000 does not require that every potential transmission need proposed by stakeholders must be selected for further evaluation. We find that this approach is a fair balance that allows interested stakeholders to submit their views on what is driving their transmission needs while allowing the process itself determine what transmission needs are identified for which solutions must be evaluated.

321. Similarly, in response to AWEA, we are not requiring anything more than what we directed in Order No. 1000, namely, the two-part identification and evaluation process. As with other Order No. 1000 transmission planning reforms, our concern is that the process allows for stakeholders to submit their views and proposals for transmission needs driven by Public Policy Requirements in a process that is open and transparent and satisfies all of the transmission planning principles set out in Order Nos. 890 and 1000, and that there is a record for the Commission and stakeholders to review to help ensure that the identification and evaluation decisions are open and fair, and not unduly discriminatory or preferential. However, we reiterate that not every proposal by stakeholders during the identification stage will necessarily be identified for further evaluation. The OATT revisions that public utility transmission providers submit as part of their Order No. 1000 compliance filings will set forth the process for permitting stakeholders to provide input and for determining which proposed transmission needs will be identified for evaluation.

322. We are also not prescribing how active a public utility transmission provider should itself be in identifying transmission needs driven by Public Policy Requirements, although it certainly may take a more proactive approach if it, in consultation with its stakeholders, so chooses. Even if a public utility transmission provider takes a less active approach on this issue, our expectation is that interested stakeholders will participate and suggest transmission needs driven by Public Policy Requirements.[363] An open and transparent transmission planning process will identify those transmission needs that should be evaluated, regardless of whether they are suggested by the public utility transmission provider or by an interested stakeholder.

323. In response to Coalition for Fair Transmission Policy, we recognize that consideration of transmission needs driven by Public Policy Requirements could create challenges in defining beneficiaries, but we fail to see how these challenges are appreciably different from those involved in determining beneficiaries of reliability or economic projects. In those cases as well, the determination of beneficiaries will often turn on informed forecasts or predictions regarding future needs and demands to be placed on the transmission system. In fact, given that the Commission is only requiring the consideration of transmission needs driven by Public Policy Requirements that are established by state or federal laws or regulations,[364] it may very well be the case that the determination of beneficiaries of transmission facilities to

[357] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 2.

[358] *Id.*

[359] *Id.* (emphasis added).

[360] *Id.* P 205.

[361] *Id.* P 209.

[362] *Id.*

[363] We emphasize that, although a public utility transmission provider is not obligated to proactively identify transmission needs driven by Public Policy Requirements, it still must consider the transmission needs driven by Public Policy Requirements raised by other stakeholders in the transmission planning process.

[364] As discussed above, the Commission clarifies that this requirement was meant to include local laws or regulations as well.

address transmission needs driven by Public Policy Requirements is easier to define than for other types of transmission facilities. In any event, we want public utility transmission providers, in consultation with stakeholders, to make those determinations in the first instance. We also disagree with Coalition for Fair Transmission Policy's argument that these reforms can only be implemented through bottom-up transmission planning. Coalition for Fair Transmission Policy has not persuaded us that these reforms cannot be implemented through either a ''top-down'' or ''bottom up'' process, particularly given the significant flexibility we are providing to public utility transmission providers to comply with these requirements.

324. Regarding American Transmission's request for clarification, we note that in Order No. 1000, footnote 185, we stated that ''[t]o the extent public utility transmission providers within a region do not engage in local transmission planning, such as in some ISO/RTO regions, the requirements of this Final Rule with regard to Public Policy Requirements apply only to the regional transmission planning process.'' [365] That statement only applies to public utility transmission providers that do not engage in local transmission planning. If a public utility transmission provider does engage in local transmission planning, regardless of whether or not it is in an ISO/RTO region, then the requirements of Order No. 1000 regarding Public Policy Requirements apply to both the local and regional transmission planning processes. Therefore, if American Transmission engages in local and regional transmission planning, then it must revise its local transmission planning process to reflect this aspect of Order No. 1000.

325. Southern Companies find the requirement that public utility transmission providers post on their Web sites an explanation of which transmission needs have been identified for evaluation and an explanation of why other suggested transmission needs will not be evaluated to be vague and overbroad. We clarify as follows. Public utility transmission providers are not required to research and post on their Web sites what they perceive to be every transmission need that is conceivably driven by a Public Policy Requirement and then explain why it will not evaluate each one. Public utility transmission providers are only obligated to (a) post an explanation of those transmission needs driven by Public Policy Requirements that have been identified for evaluation and (b) post an explanation of how other transmission needs driven by Public Policy Requirements introduced by stakeholders were considered during the identification stage and why they were not selected for further evaluation. For example, if public utility transmission providers or stakeholders in a transmission planning region submit what they believe are ten transmission needs driven by Public Policy Requirements, and five of those ten are identified for evaluation, then the public utility transmission providers must (a) post an explanation of why the five were evaluated and (b) post an explanation of why the other five were not evaluated.

326. Having provided additional clarifications and information as to what Order No. 1000 does require, i.e., the consideration of transmission needs driven by Public Policy Requirements, we now turn to discussing what Order No. 1000 does not require, i.e., the consideration of Public Policy Requirements themselves, as well as otherwise allowing public utility transmission providers to become policymakers, as some petitioners appear to believe. Order No. 1000 does not require public utility transmission providers to amend their OATTs to provide for the consideration of Public Policy Requirements. Nor do we believe that anything in Order No. 1000's reforms on this issue will lead to that outcome.

327. It is not the function of the transmission planning process to reconcile state policies. If the utilities in one state are required, for example, to procure wind resources and the utilities in another state are required to shut down old fossil units and construct new fossil units, it is not the transmission providers' function to decide on the merits of these federal or state requirements or to decide between wind and coal resources. It is their function to help both sets of utilities comply with the laws they each face by considering in the transmission planning process, but not necessarily including in the regional transmission plan, the new transmission facilities needed by both sets of utilities to meet their obligations, and also to determine if these diverse objectives can be met more efficiently or cost-effectively through regional transmission planning than through individual utility planning.

328. Additionally, in establishing this process, we are not requiring public utility transmission providers to make any substantive determinations as to what Public Policy Requirements may qualify under these reforms or to identify them in their OATTs. If they choose to do so, then such proposals must be vetted through the local and regional transmission planning process, as discussed in Order No. 1000.

329. For these reasons, we reject assertions that we are allowing public utility transmission providers to assume the role of policymaker in their transmission planning processes with respect to considering transmission needs driven by Public Policy Requirements. We also disagree with Ad Hoc Coalition of Southeastern Utilities that these reforms may lead to skewed decision-making. Our intent is to help develop a path to allow public utility transmission providers to consider transmission needs driven by Public Policy Requirements, just as they consider reliability-driven and economic-driven transmission needs, but we are not mandating that any particular transmission facility identified to address identified transmission solutions be built.

330. Further, we disagree with PSEG Companies' argument that, by requiring the development of a process, we are somehow getting ahead of the states' own public policy efforts. Nothing in the development of this process preempts or conflicts with state-level public policy efforts. Indeed, Order No. 1000 and state-level Public Policy Requirements should be complementary—Order No. 1000's intent is to establish a space in the transmission planning process to identify transmission needs driven by Public Policy Requirements and to evaluate potential solutions to identified needs.

331. We also decline to require that regional transmission plans support multiple likely power supply scenarios should a region's public policy vision not come to fruition, as requested by Transmission Access Policy Study Group. It may well be the case that evaluating different power supply scenarios will be an effective way of identifying more efficient or cost-effective transmission solutions; however, we will not prescribe any such requirements here, consistent with our preference for regional flexibility in designing regional transmission planning processes. Stakeholders may advocate for such a requirement in the development of Order No. 1000 compliance filings and, to the extent such language is included in the

[365] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at n.185.

compliance filing, the Commission will consider that language.[366]

332. Just as Order No. 1000 did not intend for public utility transmission providers to consider Public Policy Requirements, Order No. 1000 also does not convert public utility transmission providers into policymakers with respect to the consideration of public policy objectives that are not codified in federal or state laws or regulation. On this matter, Order No. 1000 stated: ''[T]he Final Rule does not preclude any public utility transmission provider from considering in its transmission planning process transmission needs driven by additional public policy objectives not specifically required by state or federal regulations.'' [367] Some petitioners expressed alarm that we are permitting public utility transmission providers to become policymakers and substitute their policy judgments in place of legislators and regulators. This was not our intent, and we take this opportunity to provide some clarifications on this matter.

333. We reiterate the observations we made in Order No. 1000. A public utility transmission provider ''has, and always had, the ability to plan for any transmission system needs that it foresees. Our recognition of this ability is not intended to limit *or expand* in any way the option that a public utility transmission provider has always had to plan for facilities that it believes are needed if it chooses to do so.'' [368] All this statement was intended to convey was that, even absent the requirements in Order No. 1000, public utility transmission providers take a number of different factors into account in developing their transmission plans. While Order No. 1000 established a requirement for certain factors that must be considered in transmission planning, as the quoted sentence states, it does not expand what public utility transmission providers have always been entitled to do. If, for example, a state law that has been identified as a Public Policy Requirement requires utilities to meet a 10 percent renewable portfolio standard and that state's governor urges them to meet a 20 percent standard, Order No. 1000 requires consideration of transmission needed to meet the 10 percent but neither requires utilities to, nor prohibits them from, considering a 20 percent standard, as some petitioners apparently urge us to do.

334. Order No. 1000 concluded that it is appropriate to require public utility transmission providers, in consultation with stakeholders, to design the appropriate procedures for identifying and evaluating the transmission needs that are driven by Public Policy Requirements in their area, subject to guidance the Commission provided in Order No. 1000 and our review on compliance.[369] Additionally, in response to Long Island Power Authority, we anticipate that the process for identifying transmission needs driven by Public Policy Requirements can identify what parties are subject to the Public Policy Requirements and whether such parties have a need for a transmission solution to meet those requirements.

335. With respect to the contention raised by Sacramento Municipal Utility District, Ad Hoc Coalition of Southeastern Utilities, and others that existing transmission planning processes already account for state renewable energy goals, we note that we are not endorsing, nor does the Public Policy Requirement include, any particular state or federal law or regulation as special or ''preferred.'' Further, as we have noted elsewhere, we understand that some regions may already be in compliance with many of the requirements of Order No. 1000 and thus may need to make only modest changes to comply. Compliance filers must explain how their process gives all stakeholders a meaningful opportunity to submit what they believe are transmission needs driven by Public Policy Requirements, and allow an open and transparent transmission planning process to determine whether to move forward regarding those needs.

336. Further, we disagree that we have not justified this reform generically, as suggested by Ad Hoc Coalition of Southeastern Utilities, which argues that there is no need for this reform in the Southeast. As discussed above and in Order No. 1000, we concluded that there was a need for the Commission to act under FPA section 206 to remedy a deficiency that we found in existing transmission planning processes. There was no formal requirement for public utility transmission providers to consider transmission needs driven by Public Policy Requirements, despite the fact that the record indicates that in recent years there has been significant activity at the federal and state levels in enacting laws and regulations that will potentially impact transmission needs.[370] The lack of a formal requirement in public utility transmission providers' OATTs to address this issue is, in our view, unjust, unreasonable, and unduly discriminatory.[371] We affirm our conclusion that these reforms are necessary on a nationwide basis.

337. Finally, some state regulators question their role in this process. We agree with petitioners that state regulators play an important and unique role in the transmission planning process, given their oversight over transmission siting, permitting, and construction, as well as integrated resource planning and similar processes. Additionally, they may be in the best position of determining how state-level public policy requirements are satisfied. Nonetheless, for the reasons discussed fully above, the Commission will not require as part of this generic rulemaking proceeding a particular status for state regulators in the transmission planning process.[372] To do so would ignore the wide range of roles that state regulators themselves tell us that they are permitted to take under their various state laws.

338. However, as we also explained in Order No. 1000 and above, our expectation is that state regulators should play a strong role and that public utility transmission providers will consult closely with state regulators to ensure that their respective transmission planning processes are consistent with state requirements. We believe this will be particularly true in the case of state-level Public Policy Requirements, where state regulators are likely to have unique insights as to how transmission needs driven by those state-level Public Policy Requirements should be satisfied. Thus, we leave it to state regulators and public utility transmission providers, in consultation with stakeholders, in each transmission planning region to determine the appropriate role of state regulators in the transmission planning process generally and in the consideration of transmission needs driven by Public Policy Requirements in particular.

339. In response to Illinois Commerce Commission, we are not prescribing how any committee of state regulators should be comprised. We note that existing committees of state regulators have been effective representatives of

[366] Similarly, we will not require the adoption of a ''least regrets'' process or processes that resulted in the development of transmission projects such as the CapX2020 project; however, the public utility transmission providers in each region are free to develop such processes and submit them in their compliance filing for Commission consideration.

[367] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 216.

[368] *Id.* (emphasis added).

[369] *Id.* P 208.

[370] *See, e.g.,* Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at PP 45–47.

[371] *Id.* PP 82–83. *See also* discussion *supra* at section II.C (explaining need for Order No. 1000's reforms).

[372] *See* discussion *supra* at section III.A.2.

state regulators, and any region that wants to form such a committee may want to look to these and other similar organizations in other regions of the country as possible models for organizing its own similar committees for purposes of regional transmission planning under Order No. 1000.

B. Nonincumbent Transmission Developers

340. This section of Order No. 1000 addressed the removal from Commission-jurisdictional tariffs and agreements of provisions that contain a federal right of first refusal [373] to construct transmission facilities selected in a regional transmission plan for purposes of cost allocation. The Commission also adopted a framework that requires the development of qualification criteria and protocols to govern the submission and evaluation of proposals for transmission facilities to be evaluated by public utility transmission providers in the regional transmission planning process. The Commission further required that the developer of any transmission facility selected in the regional transmission plan have a comparable opportunity to allocate the cost of such transmission facility through a regional cost allocation method or methods.[374]

1. Legal Authority

a. Final Rule [375]

341. In Order No. 1000, the Commission found that a federal right of first refusal is, in the language of FPA section 206, a ''rule, regulation, practice, or contract'' affecting the rates for jurisdictional transmission service. The Commission further stated that under section 206 when the Commission finds that such rules, regulations, practices, or contracts are unjust, unreasonable, unduly discriminatory, or preferential, it must determine by order the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force. The Commission concluded that because federal rights of first refusal in favor of incumbent transmission providers deprive customers of the benefits of competition in transmission development, and associated potential savings, these federal rights of first refusal affect the rates for jurisdictional transmission service, and so the Commission was compelled under FPA section 206(a) to take corrective action. The Commission also stated that federal rights of first refusal create opportunities for undue discrimination and preferential treatment against nonincumbent transmission developers within existing regional transmission planning processes, and noted that it has a responsibility to consider anticompetitive practices and eliminate barriers to competition.[376]

342. The Commission noted that nothing in Order No. 1000 is intended to limit, preempt, or otherwise affect state or local laws or regulations with respect to construction of transmission facilities, including, but not limited, to authority over siting or permitting of transmission facilities. The Commission therefore determined that its reforms regarding elimination of federal rights of first refusal from Commission-jurisdictional tariffs and agreements are not prevented or otherwise limited by the FPA. The Commission also explained that in directing the removal of a federal right of first refusal from Commission-jurisdictional tariffs and agreements, it is not ordering public utility transmission providers to enlarge their transmission facilities under sections 210 or 211 of the FPA, nor making findings related to its authorities under section 215 or 216.

343. The Commission also stated that, while a public utility transmission provider may have accepted an obligation to build in relation to its membership in an RTO/ISO, the Commission did not believe that obligation is necessarily dependent on the incumbent transmission provider having a corresponding federal right of first refusal to prevent others from constructing and owning new transmission facilities in that region.[377] The Commission stated that, while implementing these reforms may change the package of benefits and burdens in place for transmission owning members of RTOs/ISOs, such changes are necessary to correct practices that may be leading to unjust and unreasonable rates.[378]

344. Finally, the Commission declined to address the merits of comments arguing that section 3.09 of the ISO New England Transmission Operating Agreement establishes a federal right of first refusal that can be modified only if the Commission meets the *Mobile-Sierra* public interest standard, explaining that it was more appropriate to address this issue as part of the proceeding on ISO New England's compliance filing.[379]

b. Requests for Rehearing and Clarification

i. Arguments That the Commission Does Not Have the Authority To Eliminate a Federal Right of First Refusal

345. Several petitioners argue that the Commission acted outside of its authority by requiring the removal of the federal right of first refusal from Commission-jurisdictional tariffs and agreements.[380] Some petitioners assert that section 206 only extends to behavior that directly affects rates or the provision of jurisdictional service rather than to any term in a jurisdictional tariff or agreement.[381] They argue the federal right of first refusal is not a practice within the meaning of section 206, and therefore is not a behavior that the Commission can address under that section.[382] Similarly, Oklahoma Gas and Electric Company states that the Commission must show a direct and significant effect on jurisdictional rates before it can regulate actions indirectly affecting activity falling under state jurisdiction.

346. Petitioners also analogize the Commission's action in Order No. 1000 with its failed attempt to regulate corporate governance and structure, which was at issue in *CAISO* v. *FERC*.[383] Petitioners argue that the federal right of first refusal affects a transmission provider's financial relationship with its customers no more than the DC Circuit found governance to in *CAISO* v. *FERC*.[384] According to Baltimore Gas & Electric, the court in *CAISO* v. *FERC* explained that the

[373] We continue to use the phrase ''federal right of first refusal'' to refer only to rights of first refusal that are created by provisions in Commission-jurisdictional tariffs or agreements. Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 253 n.231.

[374] *Id.* P 225.

[375] We address legal arguments related to the need for our nonincumbent transmission developer reforms in the ''Need for Reform'' discussion. *See* discussion *supra* at section 0.

[376] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 286.

[377] *Id.* P 261.

[378] *Id.*

[379] *Id.* P 292.

[380] *See, e.g.,* FirstEnergy Service Company; Baltimore Gas & Electric; Southern Companies; Ad Hoc Coalition of Southeastern Utilities; and Sponsoring PJM Transmission Owners.

[381] *See, e.g.,* FirstEnergy Service Company; Sponsoring PJM Transmission Owners; Baltimore Gas & Electric; and Oklahoma Gas and Electric Company.

[382] *See, e.g.,* Southern Companies; Sponsoring PJM Transmission Owners; Baltimore Gas & Electric; and Oklahoma Gas and Electric Company.

[383] Sponsoring PJM Transmission Owners at 5–6 (citing *California Indep. Sys. Operator Corp.* v. *FERC,* 372 F.3d 403 (D.C. Cir. 2004) (*CAISO* v. *FERC*)); Southern Companies at 60–61 (citing *CAISO* v. *FERC,* 372 F.3d 395); PSEG Companies; Baltimore Gas & Electric (citing *CAISO* v. *FERC,* 372 F.3d at 403; *City of Cleveland* v. *FERC,* 773 F.2d 1368 (DC Cir. 1985)); Oklahoma Gas and Electric Company at 9–10 (*CAISO* v. *FERC,* 372 F.3d at 403).

[384] Southern Companies at 60–61 (citing *CAISO* v. *FERC,* 372 F.3d 395); Sponsoring PJM Transmission Owners at 7 (citing *CAISO* v. *FERC,* 372 F.3d at 403 (quoting *Mich. Wisc. Pipeline Co.,* 34 FPC ¶ 621,626 (1965))).

Commission cannot regulate ''practices'' using its section 206 ratemaking authority unless the practices ''affect rates and services significantly * * * are realistically susceptible of specification, and * * * are not so generally understood in any contractual arrangement as to render recitations superfluous.'' [385] Sponsoring PJM Transmission Owners also note that the *CAISO* court explained that a more expansive interpretation of ''practice'' would allow the Commission to regulate a range of subjects that the court considered to be plainly beyond the Commission's proper authority. Sponsoring PJM Transmission Owners add that, while the costs the transmission provider incurs to construct or procure an upgrade will be reflected in its rates, the same could be said of a myriad of other decisions the transmission provider makes, ranging from its hiring of staff to the procurement of outside services and materials. Southern Companies also analogize Order No. 1000 to *CAISO* v. *FERC,* arguing that the Commission, without evidence or a record of systemic abuse or actual discrimination or unreasonable decision making, is using sections 205 and 206 and a theoretical threat of unjust and unreasonable rates or discrimination in the provision of transmission service to replace the existing business investment decision process with its own.[386]

347. Sponsoring PJM Transmission Owners also point out that the court in *CAISO* v. *FERC* found that section 305 of the FPA, giving the Commission authority over interlocking directorates, would not have been necessary if it intended that the Commission could regulate corporate governance as a practice affecting rates under sections 205 and 206 of the FPA. They contend that this same reasoning leads to the conclusion that section 206 does not encompass the assignment of construction responsibility. Sponsoring PJM Transmission Owners argue that this is clear in looking at the relationship of section 7 of the NGA to sections 4 and 5 of the NGA, which parallel sections 205 and 206 of the FPA. They assert that section 7 of the NGA, giving the Commission the authority to regulate pipeline construction, would not have been necessary if sections 4 and 5 of the NGA (which parallel sections 205 and 206 of the FPA) already allowed the Commission to regulate such construction.[387] In addition, Sponsoring PJM Transmission Owners state that it is significant that, when deliberating on the FPA, Congress rejected provisions that would have given the Commission authority to order a utility to fix the services, equipment, or facilities it is responsible for maintaining upon determining they were improperly maintained.[388]

348. Sponsoring PJM Transmission Owners also analogize the right of first refusal to *Interstate Commerce Commission* v. *Pennsylvania.*[389] They contend that the court in *CAISO* v. *FERC* looked to this case because the court in *Interstate Commerce Commission* v. *Pennsylvania* interpreted the Interstate Commerce Act upon which Part II of the FPA is based and which likewise authorized the regulation of practices affecting rates.[390] Sponsoring PJM Transmission Owners assert the court in *Interstate Commerce Commission* v. *Pennsylvania* made clear that it was manifestly concerned about practices that directly related to the jurisdictional service provided customers (which was rail service), rather than the railroads' decisions regarding the means to provide such service.[391]

349. Instead of finding that any rate is unjust and unreasonable, Baltimore Gas & Electric argues that the Commission states that there may be a superior alternative practice to the present federal right of first refusal regime. Baltimore Gas & Electric asserts that this is contrary to well-settled law, which requires that if the existing method is just and reasonable, then that is the end of the section 206 inquiry even if an alternative method may be better.[392] Baltimore Gas & Electric asserts that the Commission violated this ratemaking precept by conflating its consideration of the federal right of first refusal mechanism for designating new transmission construction and operation responsibility with its consideration of an alternative selection process that the Commission prefers.

350. PSEG Companies assert that elimination of the federal right of first refusal was arbitrary and capricious because the ''remedy'' far exceeded the purported harm. Similarly, Baltimore Gas & Electric asserts that proportionality between the identified problem and the remedy ''is the key,'' and that if the Commission found isolated problems, a market-wide remedy would be inappropriate.[393] Similarly, Baltimore Gas & Electric asserts that the Commission must adduce hard facts, and that the remedy should be narrowly tailored to fit the facts.

351. With regard to the Commission's determination that the existence of a federal right of first refusal creates an opportunity for undue discrimination and preferential treatment against nonincumbent transmission developers, several petitioners argue that the Commission cannot rely on the FPA's undue discrimination provisions in sections 205 and 206 because these provisions only protect customers of public utilities, and not nonincumbent transmission developers.[394] They argue

[385] Baltimore Gas & Electric at 12 (quoting *CAISO* v. *FERC,* 372 F.3d at 403).

[386] Southern Companies at 103–104 (citing *CAISO* v. *FERC,* 372 F.2d at 395).

[387] Sponsoring PJM Transmission Owners. Similarly, Sponsoring PJM Transmission Owners assert that section 402 of the Transportation Act of 1920 (superseded by 49 U.S.C. 10901 (2010)), which provided the Interstate Commerce Commission with approval authority for railway extensions, would not have been necessary if practices affecting rates included construction decisions.

[388] Sponsoring PJM Transmission Owners at 11 (citing *Duke Power Co.* v. *Fed. Power Comm'n,* 401 F.2d 930, 943 n.106 (D.C. Cir. 1968)). They add that, although the statutory interpretations of later Congresses is not determinative of the statutory intent of an earlier Congress, it is informative that when Congress granted backstop siting authority to the Commission in the Energy Policy Act of 2005, it established clear limits that constrain the exercise of that authority. *Id.* (citing 16 U.S.C. 824p (2010); *Piedmont Envtl. Council* v. *FERC,* 558 F.3d 304 (4th Cir. 2009). They also state that section 1211 of the EPAct 2005 expressly states that the new electric reliability provisions do not authorize the Commission to order the construction of additional transmission facilities. *Id.* (referencing 16 U.S.C. 824o(i)(2)).

[389] Sponsoring PJM Transmission Owners at 9–10 (citing *Interstate Commerce Commission* v. *Pennsylvania,* 242 U.S. 208 (1916) (*ICC* v. *Pennsylvania*)).

[390] Sponsoring PJM Transmission Owners at 9–10 (citing *ICC* v. *Pennsylvania,* 242 U.S. 208)).

[391] Sponsoring PJM Transmission Owners at 9–10 & n.20 (citing *ICC* v. *Pennsylvania,* 242 U.S. 208; *Duncan* v. *Walker,* 533 U.S. 167, 174 (2001)).

[392] Baltimore Gas & Electric at 10–11 (citing *Complex Consol. Edison Co. of N.Y.* v. *FERC,* 165 F.3d 992, 1003 (D.C. Cir. 1999); *Pub. Serv. Comm'n of N.Y.* v. *FERC,* 642 F.2d 1335 (D.C. Cir. 1980) *cert. denied,* 454 U.S. 879 (1981); *Kern River Gas Transmission Co.,* Opinion No. 486–E, 136 FERC ¶ 61,045 (2011)).

[393] PSEG Companies at 33 (quoting *Public Utils. Comm'n of the State of Cal.* v. *FERC,* 462 F.3d 1027, 1054 (9th Cir. 2006)).

[394] *See, e.g.,* Southern Companies at 62 (citing *Pub. Serv. Co. of Ind., Inc.* v. *FERC,* 575 F.2d 1204, 1213 (7th Cir. 1978); *see St. Michaels Util. Comm'n* v. *FPC,* 377 f.2d 912, 915 (4th Cir. 1967)); Sponsoring PJM Transmission Owners at 12 (citing *Maine Pub. Serv. Co.* v. *FPC,* 579 F.2d 659, 664 (1st Cir. 1978)); *see also, e.g., FPC* v. *Sierra Pacific Power Co.,* 350 U.S. 348, 355 (1956); *Mun. Light Bds.* v. *FPC,* 450 F.2d 1341, 1348 (D.C. Cir. 1971); Baltimore Gas & Electric; Large Public Power Council; Ad Hoc Coalition of Southeastern Utilities at 59 (citing *Pub. Serv. Co. of Ind.* v. *FERC,* 575 F.2d 1203, 1213 (7th Cir. 1978); *St. Michaels util. Comm'n* v. *FPC,* 377 F.2d 912, 915 (4th Cir. 1967); *City of Frankfort, Ind.* v. *FERC,* 678 F.2d 699, 707 (7th Cir. 1982) (*Frankfort* v. *FERC*); *Towns of Alexandria, Minn.* v. *FPC,* 555 F.2d 1020, 1028 (D.C. Cir. 1977)); Oklahoma Gas and Electric Company at 7–8 (citing *St. Michaels Util. Comm'n* v. *FPC,* 377 F.2d at 915; *Pub. Serv. Co. of Ind., Inc.* v. *FERC,* 575 F.2d at 1212 (stating that the intent of the statute's undue discrimination protections ''is

that had Congress intended to grant the Commission such authority, it would have done so.[395] Large Public Power Council and Ad Hoc Coalition of Southeastern Utilities note that the court, in the *City of Frankfort,* stated that section 205 provisions ''regarding unlawful preference or advantage in setting of public utility rates requires that utility customers be treated fairly.'' [396] They also cite *Public Service Co. of Ind.* where the court stated that ''the anti-discrimination policy in section 205(b) is violated * * * where one consumer has its rates raised significantly above what other similarly-situated customers are paying.'' [397] Oklahoma Gas & Electric Company contends that neither of the cases the Commission cites support a different conclusion, claiming that, in *Gulf States,* the Commission addressed the narrow question of whether public utilities could ''employ tariff provisions to foreclose wholesale competition,'' [398] and that in *Otter Tail,* the Supreme Court held that the FPA was not intended ''to be a substitute for, or to immunize Otter Tail from, antitrust regulation.'' [399]

352. Petitioners also argue that the Commission lacks the authority to remedy all instances of undue discrimination, and only is responsible for promoting competition if anticompetitive behavior has a direct effect on rates.[400] In support, Sponsoring PJM Transmission Owners argue that *CAISO* v. *FERC* demonstrates that the Commission could not remedy a discriminatory governance structure of an independent system operator, and that the Supreme Court has held that the Commission does not have the authority to remedy racial discrimination in a utility's hiring practices.[401] Furthermore, Sponsoring PJM Transmission Owners argue that the Commission cannot rely on the court's affirmation of Order Nos. 436 [402] and 888 [403] as support for its asserted authority to remedy any and all discrimination. Furthermore, Sponsoring PJM Transmission Owners, similar to Oklahoma Gas & Electric, assert that the court in *Otter Tail Power Co.* v. *United States* concluded that the Commission lacked the authority to compel interconnection based on antitrust considerations alone.[404] Sponsoring PJM Transmission Owners also argue that *Gulf States Utilities Co.,*[405] cited by the Commission, did not assert responsibility to promote competition in the abstract. Sponsoring PJM Transmission Owners assert that this lack of authority to act solely on antitrust considerations, in the absence of an impact on jurisdictional services, contrasts with the Commission's authority to compel open access as a remedy for undue discrimination in transmission access, a jurisdictional service.[406]

353. Several petitioners contend that even if the Commission had the authority to address discrimination against nonincumbents, no undue discrimination against nonincumbents exists for the Commission to remedy under section 206.[407] Instead, some petitioners argue that Order No. 1000 institutionalizes undue discrimination against incumbent transmission owners in violation of the FPA and APA because it mandates similar treatment for incumbent transmission owners and nonincumbent transmission developers when they are not similarly situated.[408] In support, petitioners argue that the Commission failed to consider evidence of the full scope of risks faced by incumbent utilities.[409] For instance, several petitioners argue that incumbents have an obligation to serve customers and must comply with state legal and regulatory requirements, while nonincumbents are free to pick and choose among transmission investment options.[410] Others argue that incumbents are obligated to build under RTO contracts.[411]

354. Some petitioners also argue that it is unclear whether nonincumbent developers will have the same responsibilities as incumbent developers when operating their facilities. For instance, petitioners question whether there is a practical enforcement mechanism to ensure that a nonincumbent developer will build its transmission facility and then safeguard it from threats, such as cyber attacks.[412] Transmission Dependent Utility Systems argue that even if the nonincumbent developer were to be assessed penalties for reliability violations, NERC penalties may be insufficient for a merchant transmission developer that, in the absence of a franchised service territory obligation, may walk away from its contractual commitments or become financially unable to meet them.

355. In related arguments, some petitioners disagree with the Commission's conclusion that the federal right of first refusal is not dependent on an obligation to build.[413] They argue that the obligation to build under an RTO or ISO is not an ''option,'' but rather imposes a duty of diligence in fulfilling construction obligations. Baltimore Gas & Electric argues that the Commission has misconstrued what a federal right of first refusal is, which it argues is another way of saying that it has a right of notification from PJM whenever PJM determines that transmission needs to be built in Baltimore Gas & Electric's service area since Baltimore Gas & Electric is required to build it. Baltimore Gas & Electric argues that the Commission's ruling on this issue is invalid because

to protect consumers from being placed at a competitive disadvantage with other [similar customers]''); *Frankfort* v. *FERC,* 678 F.2d at 707 ; *Towns of Alexandria, Minn.* v. *FPC,* 555 F.2d 1020, 1028 (D.C. Cir. 1977)).

[395] Oklahoma Gas & Electric at 6 (citing *Dunk* v. *Penn. Pub. Util. Comm'n,* 252 A.2d 589, 591–92 (Pa. 1969)). It also contrasts the absence of such language in the FPA with the Natural Gas Act and Part I of the FPA (addressing hydroelectric facilities).

[396] Ad Hoc Coalition of Southeastern Utilities at 59 (quoting *Frankfort* v. *FERC,* 678 F.2d at 704); Large Public Power Council at 32 (quoting *Frankfort* v. *FERC,* 678 F.2d at 707).

[397] *See, e.g.,* Ad Hoc Coalition of Southeastern Utilities at 59–60 (quoting *Pub. Serv. Co. of Ind.* v. *FERC,* 575 F.2d at 1213); Large Public Power Council at 32 (quoting *Pub. Serv. Co. of Ind., Inc.* v. *FERC,* 575 F.2d at 1213).

[398] *Gulf States Utils. Co.,* 5 FERC ¶ 61,066 at 61,098 (1978).

[399] *Otter Tail Power Co.* v. *United States,* 410 U.S. 366, 374–75 (1973) (*Otter Tail* v. *U.S.*).

[400] Sponsoring PJM Transmission Owners at 14; Ad Hoc Coalition of Southeastern Utilities at n.176 (citing *Entergy Services Inc.,* 64 FERC ¶ 61,001 at ¶ 61,013, n.66 (1993); *Cargill, Inc.* v. *Montfort of Colorado, Inc.,* 479 U.S. 104, 115–117 (1976)).

[401] Sponsoring PJM Transmission Owners at 12 (citing *CAISO.* v. *FERC,* 372 F.3d 400; *NAACP* v. *FPC,* 425 U.S. 662 (1976)).

[402] *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol,* Order No. 436, FERC Stats. & Regs. ¶ 30,665, at 31,502 (1985).

[403] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Pub. Utils.; Recovery of Stranded Costs by Pub. Utils. and Transmitting Utils.,* Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g,* Order No. 888–A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g,* Order No. 888–B, 81 FERC ¶ 61,248 (1997), *order on reh'g,* Order No. 888–C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group* v. *FERC,* 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York* v. *FERC,* 535 U.S. 1 (2002)).

[404] Sponsoring PJM Transmission Owners at 14 (citing 410 U.S. 366 (1973)).

[405] *Gulf States Util. Co.,* 5 FERC ¶ 61,066 at 61,098.

[406] Sponsoring PJM Transmission Owners at 15 (citing *Transmission Access Policy Study Group* v. *FERC,* 225 F.3d 667, 686 (D.C. Cir. 2000)).

[407] *See e.g.,* Ameren; PSEG Companies; and MISO Transmission Owners Group.

[408] *See, e.g.,* MISO Transmission Owners Group 2; and Ameren.

[409] *See, e.g.,* Ameren; Southern Companies; and MISO Transmission Owners Group 2.

[410] *See, e.g.,* Ameren; PSEG Companies; MISO Transmission Owners Group; and Southern Companies.

[411] *See, e.g.,* MISO Transmission Owners Group 2; and PSEG Companies.

[412] *See, e.g.,* Baltimore Gas & Electric; and Transmission Dependent Utility Systems.

[413] *See, e.g.,* Baltimore Gas & Electric; and MISO.

the Commission failed to appreciate what a federal right of first refusal is. MISO states that since it does not own any transmission facilities, it needs to rely on the transmission owners' obligation to build under the Transmission Owners Agreement to ensure MISO's ability to fulfill its transmission planning and expansion responsibilities as an RTO. MISO states that its membership could be significantly eroded and its existence could be jeopardized, as well as its rate significantly affected, if the Commission were to modify this fundamental element of MISO's structure as an RTO.

356. PSEG Companies contend that the elimination of the federal right of first refusal is a taking in violation of the Fifth Amendment to the U.S. Constitution because it renders meaningless the contractually-based consideration transmission owners received when they transferred control of their transmission facilities to ISOs/RTOs. They note that takings may not only be regulatory in nature but could include contractual takings.[414] According to PSEG Companies, language in the PJM Transmission Owners Agreement created the reasonable investment-backed expectation among incumbent transmission owners that they could participate in an RTO arrangement and commit to build everything needed for reliability purposes while still preserving fundamental rights, such as the right to build in their respective zones. PSEG Companies conclude that the Commission's impairment of this contractual right of first refusal creates unspecified economic injuries that, without just compensation, violate the U.S. Constitution.

(a) Commission Determination

357. We affirm the decision in Order No. 1000 that the Commission has the legal authority under section 206 of the FPA to require the elimination of federal rights of first refusal as practices that have the potential to lead to Commission-jurisdictional rates that are unjust and unreasonable or unduly discriminatory or preferential.[415] At the outset, it is important to emphasize the scope of the Commission's requirement to eliminate federal rights of first refusal. In Order No. 1000, the Commission required public utility transmission providers to remove from Commission-jurisdictional tariffs and agreements provisions that grant a federal right of first refusal to construct transmission facilities selected in a regional transmission plan for purposes of cost allocation.[416] The Commission did not, however, require public utility transmission providers to remove a federal right of first refusal for local transmission facilities or upgrades to an incumbent transmission provider's own transmission facilities, and did not alter an incumbent transmission provider's use and control of an existing right of way.[417]

358. We affirm the decision in Order No. 1000 that a federal right of first refusal is a practice that falls squarely within the interpretation of a practice affecting rates.[418] To this end, contrary to the argument of some petitioners, the Commission affirms that the *CAISO* v. *FERC* decision supports the Commission's position. As discussed in Order No. 1000, the court in *CAISO* v. *FERC* explained that the Commission is empowered under section 206 to assess practices that directly affect or are closely related to a public utility's rates and ''not all those remote things beyond the rate structure that might in some sense indirectly or ultimately do so.''[419] As explained in Order No. 1000, we meet this standard because here we are focused on the effect that federal rights of first refusal in Commission-approved tariffs and agreements have on competition and in turn the rates for jurisdictional transmission services. For example, as the Commission explained in Order No. 1000, the selection of transmission facilities in a regional transmission plan for purposes of cost allocation is directly related to costs that will be allocated to jurisdictional ratepayers.[420] The ability of an incumbent transmission provider to discourage or preclude participation of new transmission developers through discriminatory rules in a regional transmission planning process, and in particular, the inclusion of a federal right of first refusal, can have the effect of limiting the identification and evaluation of potential solutions to regional transmission needs.[421] This in turn can directly increase the cost of new transmission development that is recovered from jurisdictional customers through rates.[422]

359. Sponsoring PJM Transmission Owners argue that section 7 of the NGA, which gives the Commission authority to regulate pipeline construction, demonstrates that had Congress desired to give the Commission authority over construction of transmission lines it would have done so. However, Sponsoring PJM Transmission Owners misconstrue the Commission's actions in Order No. 1000. As the Commission explicitly stated in Order No. 1000, it is not regulating construction of new transmission facilities because that is a matter reserved to the states.[423] Instead, the Commission acted under its legal authority in section 206 to require the elimination of provisions in federally-regulated tariffs establishing practices in the regional transmission planning process that affect rates. The authority to authorize construction and siting of new transmission facilities is distinct from the authority to require public utility transmission providers to engage in an open and transparent regional transmission planning process designed to ensure that the more efficient or cost-effective solutions to regional transmission needs are selected in the regional transmission plan for purposes of cost allocation.

360. Contrary to Baltimore Gas & Electric's arguments, the Commission made a finding in Order No. 1000 that granting an incumbent transmission provider a federal right of first refusal with respect to transmission facilities selected in a regional transmission plan for purposes of cost allocation can lead to rates for Commission-jurisdictional services that are unjust and unreasonable or otherwise result in undue discrimination by public utility transmission providers.[424] Consistent with section 206, the Commission acted to remedy an unjust and unreasonable or unduly discriminatory or preferential practice by requiring public utility transmission providers to eliminate such provisions from Commission-jurisdictional tariffs or agreements and adopt the nonincumbent transmission developer reforms. In addition, the Commission's decision to require public utility transmission providers to adopt the nonincumbent transmission developer reforms was an appropriate, and adequately tailored, remedy in light of the Commission's conclusion that it is not in the economic self-interest of public utility transmission providers to permit new entrants to develop

[414] PSEG Companies at 36 (citing *Tahoe-Sierra Preservation Council, Inc.* v. *Tahoe Regional Planning Agency,* 535 U.S. 302, 332 (2002); *Armstrong* v. *United States,* 364 U.S. 40, 49 (1960)).

[415] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 284.

[416] *Id.* P 226.

[417] *Id.*

[418] *Id.* P 285.

[419] *CAISO* v. *FERC,* 372 F.3d at 403.

[420] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 289.

[421] *Id.* P 284.

[422] *Id.*

[423] *Id.* P 287 (''Eliminating a federal right of first refusal in Commission-jurisdictional tariffs and agreements does not, as some commenters contend, result in the regulation of matters reserved to the states, such as *transmission construction,* ownership or siting.'' (emphasis added)).

[424] *Id.* PP 253, 284.

transmission facilities.[425] For instance, some commenters supported eliminating all federal rights of first refusal. On balance, however, the Commission determined that incumbent transmission providers should be able to maintain an existing federal right of first refusal for certain types of new transmission projects, including a local transmission facility and upgrades to its existing transmission facilities. The Commission clarified that its actions were not intended to diminish the significance of an incumbent transmission provider's reliability or service obligations.[426]

361. In addition to affirming our decision to act to remedy unjust and unreasonable rates, we affirm, on an independent and alternative basis, the decision in Order No. 1000 that the elimination of any federal rights of first refusal from Commission-jurisdictional tariffs and agreements is necessary to address opportunities for undue discrimination and preferential treatment against nonincumbent transmission developers within regional transmission planning processes.[427] In Order No. 1000, the Commission explained that ''it has a responsibility to consider anticompetitive practices and to eliminate barriers to competition.''[428] We continue to believe, as the Commission found in Order No. 1000, that we have a duty to consider anticompetitive practices and to eliminate barriers to competition consistent with the FPA.[429]

362. Petitioners rely on *City of Frankfort* and *Public Service Co. of Ind.* in support of their contention that section 206's prohibition on undue discrimination only protects customers of public utilities. However, the court did not, as petitioners would imply, set forth limits on who the Commission may, acting under its section 206 authority, protect from unduly discriminatory practices. Instead, the cases cited by petitioners address the applicability of section 206 in the context of a regulated utility appearing to provide favorable rates or terms to one customer, and the courts in those cases do not address whether section 206 may be used as a basis for eliminating unduly discriminatory or preferential practices between competitors. In addition, we continue to conclude that the Commission's action is in accordance with its responsibility to eliminate unduly discriminatory or preferential practices in regional transmission planning processes.

363. While we agree with petitioners that argue that the Commission does not have the authority to remedy every instance of undue discrimination, given the FPA's emphasis on promoting competition, the Commission has a responsibility to eliminate unduly discriminatory practices that come within the Commission's subject matter jurisdiction under section 201 of the FPA, which includes the transmission of electric energy in interstate commerce.[430] In Order No. 1000, the Commission found that ''federal rights of first refusal create opportunities for undue discrimination and preferential treatment against nonincumbent transmission developers within existing regional transmission planning processes.''[431] Accordingly, the Commission has acted consistent within its authority to eliminate and remedy practices that it found to be unduly discriminatory and anticompetitive. In any event, the Commission has not based its decision solely on competition concerns because, in the alternative, the Commission acted to remedy the potential for unjust and unreasonable rates for Commission-jurisdictional services in addition to promoting competition among potential transmission developers.

364. We disagree with petitioners' argument that Order No. 1000 institutionalizes undue discrimination against incumbent transmission providers. Petitioners argue that the Commission failed to consider the full scope of risks faced by incumbent transmission providers, and thus erroneously concluded that incumbent transmission providers and nonincumbent transmission developers are similarly situated. For example, some petitioners argue that many incumbent transmission providers have obligations to build placed on them under RTO and ISO member agreements. However, as explained in Order No. 1000, nonincumbent transmission developers that build a transmission facility in an RTO or ISO and become members of that RTO or ISO will be subject to the same relevant obligations that apply to incumbent transmission providers that are members of an RTO or ISO.[432] For instance, nonincumbent transmission developers also will have an obligation to expand their transmission facilities if directed to by the RTO or ISO consistent with the RTO's or ISO's tariff or governing agreement.

365. Other petitioners argue that incumbent transmission providers are not similarly situated to nonincumbent transmission developers because incumbent transmission providers, unlike nonincumbent transmission developers, must comply with reliability standards and have an obligation to serve customers. They further argue that having a federal right of first refusal is necessary to comply with these standards and obligations. While public utility transmission providers must comply with reliability standards and some public utility transmission providers have an obligation to serve,[433] we disagree that eliminating federal rights of first refusal amounts to discrimination in favor of nonincumbent transmission developers. Instead, as we stated in Order No. 1000, we are merely removing barriers to participation by all potential transmission providers in the regional transmission planning process subject to our jurisdiction. Moreover, as explained in Order No. 1000, all owners and operators of bulk-power system transmission facilities, including nonincumbent transmission developers, that successfully develop a transmission project, are required to be registered as Functional Entities[434] and must comply with all applicable reliability standards.[435] Similarly, transmission facilities selected in a regional transmission plan for purposes of cost allocation owned by a nonincumbent transmission developer would be subject to any applicable open access requirements. Accordingly, we continue to believe that the nonincumbent transmission developer reforms will not result in undue discrimination against incumbent transmission developers.

366. Similarly, we disagree with Oklahoma Gas and Electric Company that the nonincumbent transmission developer reforms materially alter the business of a public utility that has been responsible for, and entitled to earn a return from, construction of its own transmission system. As we explained in Order No. 1000, while public utilities are entitled to receive a reasonable

[425] *Id.* P 256.

[426] *Id.* P 262.

[427] *Id.* P 286.

[428] *Id.*

[429] *See Gulf States Utils. Co.,* 5 FERC ¶ 61,066 at 61,098; *Otter Tail* v. *U.S.,* 410 U.S. at 374 (''the history of Part II of the Federal Power Act indicates an overriding policy of maintaining competition to the maximum extent possible consistent with the public interest.'').

[430] 16 U.S.C. 824.

[431] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 286.

[432] *Id.* P 265.

[433] *Id.*

[434] We use the term Functional Entity to refer to any user, owner or operator of the bulk power system that is responsible for complying with a NERC reliability standard as that term is defined in section 215(a)(3) of the FPA.

[435] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 266 (citing 18 CFR part 39.2(a) (2011)).

return on their investment, they will no longer be entitled to receive from the Commission a preferential right to make those investments in new transmission facilities that are selected in a regional transmission plan for purposes of cost allocation under the provisions of Order No. 1000.[436] Inherent in Oklahoma Gas and Electric Company's argument is that incumbent transmission providers have traditionally had the opportunity to build transmission facilities for their own transmission systems. Nothing in Order No. 1000 prohibits an incumbent transmission provider from choosing to build new transmission facilities that are located solely within its retail distribution service territory or footprint and that are not selected for selection in a regional transmission plan for purposes of cost allocation.[437]

367. We are not persuaded by Baltimore Gas & Electric's argument that a federal right of first refusal is simply the recognition of an obligation to build. In Order No. 1000, we acknowledged that a public utility transmission provider may have accepted an obligation to build in relation to its membership in an RTO or ISO, but the Commission did not agree that that obligation is necessarily dependent on the incumbent transmission provider having a corresponding federal right of first refusal to prevent other entities from constructing and owning new transmission facilities located in that region.[438] We continue to believe that an obligation to build in relation to membership in an RTO or ISO is not necessarily dependent on an incumbent transmission provider having a corresponding federal right of first refusal to prevent other entities from constructing and owning new transmission facilities located in that region,[439] and Baltimore Gas & Electric has provided no evidence to the contrary. Moreover, while eliminating a federal right of first refusal may change the benefits and obligations associated with membership in an RTO or ISO, we affirm our finding in Order No. 1000 that changing the benefits and obligations is necessary to correct practices that have the potential to lead to unjust and unreasonable rates for Commission-jurisdictional transmission service.[440] Similarly, we disagree with MISO that the nonincumbent transmission developer reforms will discourage entities from maintaining membership in an RTO or ISO, because, as explained in Order No. 1000, there are a variety of factors that public utility transmission providers must weight when evaluating the benefits and burdens of RTO/ISO membership.[441]

368. We also are not convinced by PSEG Companies' argument that requiring public utility transmission providers to eliminate a federal right of first refusal for transmission projects that are selected in the regional plan for purposes of cost allocation violates the Takings Clause of the Fifth Amendment. Nor do we agree that Order No. 1000 destroys or materially impairs PSEG Companies' purported contractual right to build in their respective service areas or zones. Although some contractual rights are ''property'' within the meaning of the Taking Clause,[442] the Commission has not impaired this alleged contractual right of first refusal. Order No. 1000 continues to permit an incumbent transmission provider, such as PSEG Companies, to meet its reliability needs or service obligations by choosing to build new transmission facilities that are located solely within its retail distribution service territory or footprint as long as the transmission provider does not receive regional cost allocation for the facilities.[443]

369. Even assuming that Order No. 1000 impinges upon this alleged contractual right, PSEG Companies have not met their ''substantial burden'' to show ''whether a regulation 'reaches a certain magnitude' in depriving an owner of the use of property.''[444] Just as ''legislation [that] readjust[s] rights and burdens is not unlawful solely because it upsets otherwise settled expectations,''[445] the Order No. 1000 regulations regarding the federal right of first refusal are not unconstitutional takings solely because the regulations impact the benefits and burdens of transmission owner agreements. Furthermore, in arguing that Order No. 1000 operates to take their property, PSEG Companies have a burden to demonstrate the economic injury they expect to incur if they are denied the future exclusive opportunity to build transmission facilities in their service territory.[446] They have not met this burden in their rehearing request.

370. Finally, PSEG Companies also have not argued that Order No. 1000 appropriates their alleged contractual right of first refusal for public use. Nor could the Commission be said to be taking the federal right of first refusal so that another entity could use it for public purposes.[447] Rather, we require the elimination of such provisions so that incumbent transmission providers and nonincumbent transmission developers will have an opportunity on a comparable basis to propose new transmission facilities for selection in the regional transmission plan for purposes of cost allocation.[448] For these reasons, we find that the elimination of federal rights of first refusal does not constitute a taking under the Fifth Amendment's Taking Clause.

ii. Arguments That the Commission Is Inappropriately Regulating the Construction of Transmission

371. Several petitioners argue that the Commission's reforms impermissibly infringe on state jurisdiction to authorize construction and operation of transmission lines.[449] Ameren states that section 201(a) expressly provides that the Commission does not have authority over matters that are subject to regulation by the states, and that states have historically exercised jurisdiction over siting and construction of transmission facilities. Ameren asserts that had Congress wished to expand the Commission's jurisdiction, it would have done so by adding new sections to the FPA, such as sections 215 and 216, which gave the Commission expanded authority over reliability. Wisconsin PSC also argues that FPA sections 201 and 206 do not create a federal right to authorize transmission line construction.[450] According to PSEG

[436] *Id.* P 269.

[437] *Id.* P 262.

[438] *Id.* P 261.

[439] *Id.*

[440] *Id.*

[441] *Id.* P 265.

[442] *Connolly* v. *Pension Guaranty Corp.,* 475 U.S. 211, 224 (1986) (holding that congressional action that impinged upon employers' contractual rights did not constitute an unconstitutional taking).

[443] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 262.

[444] *District Intown Props. Ltd. Pshp.* v. *District of Columbia,* 198 F.3d 874, 878 (D.C. Cir. 1999) (citing *Pennsylvania Coal Co.* v. *Mahon,* 260 U.S. 393, 413 (1922)).

[445] *Connolly,* 475 U.S. at 223.

[446] *See Connolly,* 475 U.S. at 225 (to determine whether there is a ''taking,'' the Court evaluates three factors: ''(1) The economic impact of the regulation on the claimant; (2) the extent to which the regulation has interfered with investment-backed expectations; and (3) the character of the governmental action).

[447] *See Omnia,* 261 U.S. at 508–13 (holding that, while government requisition of steel frustrated a contract for delivery of steel, the government action was not an appropriation for public purposes that required just compensation).

[448] *Accord Nat'l Ass'n of Regulatory Util. Comm'rs* v. *FERC,* 475 F.3d 1277, 1284 (D.C. Cir. 2007) (finding that anti-discrimination rules commonly burden the obligated parties and that the burden imposed did not create an unconstitutional taking of private property).

[449] *See, e.g.,* Wisconsin PSC; Baltimore Gas & Electric; Ameren; and PSEG Companies.

[450] Wisconsin PSC at 14–15 (citing *Dunk* v. *Pennsylvania Pub. Util. Comm'n,* 434 Pa. 41, 44–45, 252 A.2d 589, 591–92, *cert. denied,* 396 U.S. 839 (1969)).

Companies, the removal of the federal right of first refusal ''immediately, directly and irreparably impacts'' the decision of who gets to site, construct, and own transmission facilities in a transmission owner's zone, and incumbent transmission owners will no longer have the threshold right to build in their respective state service territories to satisfy their obligations under state law. In addition, Baltimore Gas & Electric argues that the federal right of first refusal has nothing to do with the Commission's limited backstop authority over transmission construction.[451]

372. Ameren requests clarification that, in implementing the requirement to remove any federal right of first refusal from Commission-jurisdictional tariffs and agreements, incumbent transmission owners that have a state certified service area or local franchise service area retain the sole right to build infrastructure and serve customers in that service territory. Ameren asserts the Commission also should clarify that it does not have the authority to preempt a state law or regulation of this type. However, Southern Companies assert that the Commission should explicitly state that Order No. 1000 preempts the state-mandated duty to serve native load to the extent that a nonincumbent sponsors a transmission project needed to fulfill that duty to serve. They argue that Order No. 1000's requirements will impair the ability of incumbents to comply with their state-mandated duty to serve native load, and that these provisions might be used to argue that incumbents should be subject to ramifications under state law for a nonincumbent's delay, abandonment, or other possible wrong doing.

373. Other petitioners point out that, unlike the NGA, the FPA does not grant the Commission any authority over construction or ownership of transmission facilities.[452] Wisconsin PSC states that Order No. 1000 confusingly implies the existence in the FPA of a federal ability to confer a right to construct, which is not in the FPA, whereas the FPA reserved such authority to state jurisdiction.[453] Wisconsin PSC argues that in *Connecticut Light & Power Co.* v. *FERC,* the Supreme Court engages in an extensive discussion that suggests that even though the particular facilities and activities of a person determine whether the person is a public utility subject to the FPA, there is a limit to the agency's jurisdiction.[454] Southern Companies also state that the decision to construct or invest in a transmission facility does not belong to the Commission, except as required to grant or maintain service for transmission service customers.[455] They argue there is no authority for the proposition that the Commission may require a public utility transmission provider to plan for, construct, or fund any new transmission facility involuntarily.

374. Some petitioners argue that existing rights of first refusal in Commission-approved RTO/ISO tariffs and agreements were crafted and negotiated expressly to ensure that each incumbent load-serving transmission owner could continue to fulfill its state-imposed service obligations.[456] Baltimore Gas & Electric states that the federal right of first refusal stems from the natural monopoly franchise service obligations that retail public utilities must abide by, in part through their Commission-jurisdictional wholesale transmission lines. According to Baltimore Gas & Electric, Commission-jurisdictional tariffs and agreements merely acknowledge the right of first refusal that Baltimore Gas & Electric had before joining PJM and others had before joining other RTOs and ISOs. Thus, Baltimore Gas & Electric argues that there is no such thing as a federal right of first refusal derived from a Commission tariff, but rather a right of first refusal in a Commission tariff connotes that the transmission owner retained its existing state-granted right of first refusal when it voluntarily submitted itself to the regional planning process of whatever RTO or ISO it opted to join, if any.

375. Moreover, MISO contends that the removal of such provisions would place MISO in the role of deciding who should construct planned transmission facilities. It states that state law, not federal, governs the preconditions associated with the siting and construction of transmission and the appurtenant rights associated with such construction including, but not limited to, the right of eminent domain. As such, MISO argues that its role under Order No. 1000 should not be to determine who should build specific transmission projects identified through its transmission planning process because it has not been vested with any rights by any state legislature or state commission regarding the construction of the facilities that may be deemed necessary as a result of the MISO Transmission Expansion Plan process or any other plan developed by MISO and its stakeholders. Therefore, MISO requests that the Commission reconsider Order No. 1000's generic requirement regarding the elimination of rights of first refusal from jurisdictional tariffs and agreements, insofar as that requirement would entail modification of the Transmission Owners Agreement provisions on the transmission owners' right to build, and related tariff provisions.

376. Southern Companies argue that the Commission seeks to regulate who has the right to construct and own transmission facilities by regulating who is entitled to the benefits of the regional and interregional cost allocation processes. Southern Companies argue that nothing in section 206 confers upon the Commission authority to require, authorize, or regulate who will construct or own transmission facilities or sponsor a transmission project in a transmission planning process.[457] Similarly, Ad Hoc Coalition of Southeastern Utilities argues that although the Commission does not directly mandate construction according to regional plans, this distinction may prove to be immaterial as the financially punitive effect of constructing redundant transmission facilities makes deference to nonincumbent transmission developers effectively mandatory.[458] Large Public Power Council makes a similar argument. Ad Hoc Coalition of Southeastern Utilities and Large Public Power Council assert that this creates a dilemma for incumbent transmission developers that must effectively defer to the plans of nonincumbent developers but also must continue to satisfy their service obligations while complying with potentially costly mandatory and enforceable reliability standards.

(a) Commission Determination

377. We affirm the Commission's finding in Order No. 1000 that the nonincumbent transmission developer reforms do not result in the regulation of matters reserved to the states, such as transmission construction, ownership or

[451] Baltimore Gas & Electric at 5 (citing 16 U.S.C. 824p).

[452] *See, e.g.,* Southern Companies; and Wisconsin PSC.

[453] Wisconsin PSC at 13–14 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 334, 340).

[454] Wisconsin PSC at 14 (citing 324 U.S. 515, 525–27 (1945)).

[455] Southern Companies at 102 (citing *Alabama Power Co.* v. *FERC,* 993 F.2d 1557 (D.C. Cir. 1993)).

[456] Ameren; MISO Transmission Owners Group 2; and PSEG Companies. PSEG Companies state that their points in this regard are buttressed by comments from Pennsylvania PUC, ITC, and SPP.

[457] Southern Companies at 60 (citing *Northern Gas Co.* v. *Kansas Comm'n,* 372 U.S. 84, 91–93 (1963)).

[458] Ad Hoc Coalition of Southeastern Utilities at 57 (citing *Associated Gas,* 824 F.2d at 1000–01).

siting.[459] As the Commission explained in Order No. 1000, the nonincumbent transmission developer reforms are focused solely on public utility transmission provider tariffs and agreements subject to the Commission's jurisdiction and are not intended to limit, preempt, or otherwise affect state or local laws or regulations with respect to construction of transmission facilities, including but not limited to authority over siting or permitting of transmission facilities.[460]

378. We disagree with petitioners that argue that the Commission needs new authority in the FPA to adopt the nonincumbent transmission developer reforms, as these arguments rest on the faulty premise that the Commission is somehow regulating the construction of transmission facilities. Order No. 1000 does not address transmission construction. Instead, the nonincumbent transmission developer reforms in Order No. 1000 ensure that nonincumbent transmission developers have a comparable opportunity to incumbent transmission developers/providers to submit transmission projects for evaluation and potential selection in the regional transmission plan for purposes of cost allocation. These reforms further provide that a nonincumbent transmission developer's project that is selected in the regional transmission plan for purposes of cost allocation will not be subject to any federal right of first refusal, which must be eliminated, except in certain limited circumstances. The reforms do not, however, speak to which entity may ultimately construct any transmission facilities. Moreover, we note that we agree with Baltimore Gas & Electric that eliminating a federal right of first refusal is unrelated to the Commission's authority under section 216 of the FPA.[461]

379. We disagree with petitioners that argue that eliminating a federal right of first refusal preempts state law, or is otherwise prohibited by state law. As noted above, the Commission made clear that its reforms are focused on Commission-jurisdictional tariffs and agreements, and are not intended to preempt state or local laws or regulations. Moreover, as explained in greater detail below, an incumbent transmission provider has several choices for meeting its reliability needs and service obligations. In particular, Order No. 1000 permits an incumbent transmission provider to meet its reliability needs or service obligations by choosing to build new transmission facilities that are located solely within its retail distribution service territory or footprint and that are not selected for regional cost allocation.[462]

380. In response to Wisconsin PSC, we note that the Commission specifically declined in Order No. 1000 to adopt the proposal in the rulemaking that would have required public utility transmission providers in the regional transmission planning process to provide transmission developers a right to construct and own a transmission facility selected in a regional transmission plan for purposes of cost allocation.[463] The Commission also declined to a provide transmission developer with an ongoing right to build and own a transmission project that it proposed but that was not selected.[464] Because the Commission did not adopt these proposals, we do not need to address whether the Commission has the authority to grant them.

381. In response to Baltimore Gas & Electric's argument that Commission-jurisdictional tariffs and agreements merely acknowledge a right of first refusal that it had before joining PJM, we affirm the statement in Order No. 1000 that ''[t]his Final Rule does not require removal of references to such state or local laws or regulations from Commission-approved tariffs or agreements.'' [465] Accordingly, such a right based on a state or local law or regulation would still exist under state or local law even if removed from the Commission-jurisdictional tariff or agreement, and nothing in Order No. 1000 changes that law or regulation, for Order No. 1000 is clear that nothing therein is ''intended to limit, preempt, or otherwise affect state or local laws or regulations with respect to construction of transmission facilities.'' [466]

382. We disagree with MISO that eliminating a federal right of first refusal would put it in the position of deciding who should construct planned transmission facilities. Rather, the transmission planning and cost allocation reforms in Order No. 1000 are designed to allow the public utility transmission providers in a transmission planning region to evaluate whether new transmission facilities would efficiently and cost-effectively meet their transmission needs, as well as to provide a cost allocation method for those facilities selected in the regional transmission plan for purposes of cost allocation. We acknowledge that a decision made to select a new transmission facility in the regional transmission plan for purposes of cost allocation may affect which entity ultimately constructs and owns transmission facilities. However, we reiterate that nothing in Order No. 1000 creates any new authority for the Commission nor public utility transmission providers acting through a regional transmission planning process to site or authorize the construction of transmission projects. Furthermore, Order No. 1000 does not prohibit an incumbent transmission provider from having a federal right of first refusal for a new local transmission facility that is not selected in a regional transmission plan for purposes of cost allocation.

iii. Arguments That the Commission Must Meet the *Mobile-Sierra* Public Interest Standard Before Requiring Federal Rights of First Refusal To Be Removed From Agreements

383. Several petitioners argue that the Commission cannot modify a contractual federal right of first refusal without first making a determination that the federal right of first refusal seriously harms the public, which they argue the Commission failed to do.[467] MISO Transmission Owners Group 2 argues that in *Mobile-Sierra,* the U.S. Supreme Court found that the Commission must presume that the rate set out in a freely-negotiated wholesale energy contract meets the just and reasonable requirement, and that this presumption can be overcome only if the Commission concludes that the contract seriously harms the public interest. MISO Transmission Owners Group 2 also argues that other Supreme Court precedent found that the Commission cannot base its demand that public utility transmission providers modify existing contracts on a finding that the existing contract provisions may lead to rates that are unjust and unreasonable.[468]

[459] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 287.

[460] *Id.*

[461] 16 U.S.C. 824p (2006). Section 216 addresses the designation and siting of transmission facilities within National Interest Electric Transmission Corridors.

[462] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 262.

[463] *Id.* P 338.

[464] *Id.* P 340.

[465] *Id.* P 253 n.231.

[466] *Id.* P 287.

[467] *See, e.g.,* Ameren; Sponsoring PJM Transmission Owners at 21 (citing *Morgan Stanley Capital Group* v. *Pub. Util. Dist. No. 1 of Snohomish City.,* 554 U.S. 527, 545–46 (2008)); Baltimore Gas & Electric; PSEG Companies at 9–11, 14–15 (citing comments from Oklahoma Gas & Electric Co., Ad Hoc Coalition of Southeastern Utilities, North Dakota & South Dakota Commissions, Alabama PSC, Southern Companies, Baltimore Gas & Electric Co., MidAmerican, Pacific Gas & Electric, PJM, PSEG Companies, and Southern California Edison); MISO; MISO Transmission Owners Group 2; Northern Tier Transmission Group.

[468] MISO Transmission Owners Group 2 at 32 (citing *Morgan Stanley Capital Group, Inc.* v. *Public Utility Dist. No. 1,* 554 U.S. 527 (2008) and *NRG*

384. Some petitioners state that the federal right of first refusal is embodied in the PJM Transmission Owner's Agreement, and thus assert that the Commission must make a *Mobile-Sierra* finding before it can modify the agreement.[469] PSEG Companies argue that the Commission cannot make such a finding because nothing in Order No. 1000 or in the rulemaking record would support such a conclusion.

385. Other petitioners also argue that Order No. 1000 does not discuss how existing contractual rights of first refusal, such as that in the Midwest ISO Transmission Owners Agreement, seriously harm the public interest.[470] MISO states that while Order No. 1000 purports to avoid addressing *Mobile-Sierra* issues with regard to any particular jurisdictional agreement, the Commission erred in requiring generically in this proceeding a modification that it cannot require specifically for each jurisdictional agreement without determining that the retention of such a right in the particular agreement is against the public interest, unjust, unreasonable, or unduly discriminatory or preferential, or otherwise anticompetitive. MISO further argues that with respect to the public interest standard, the Commission cannot make a generic finding as a substitute for the specific finding it must make before declaring that the provisions of a particular agreement are contrary to the public interest.

386. In addition, PSEG Companies disagree with the statement in Order No. 1000 that this issue can be deferred until the compliance stage of this proceeding. Specifically, they take issue with the Commission's conclusion that the record was insufficient to address National Grid's comment regarding *Mobile-Sierra* and the ISO–NE operating agreement, stating that if the Commission had serious evidence of harm to the public interest then it should have had no difficulty in articulating it in Order No. 1000. PSEG Companies assert that it is ironic that while the Commission chose to engage in nationwide abrogation of individual contracts in a generic rulemaking, it seeks to avoid the required analysis on the ground that a rulemaking proceeding is an inappropriate vehicle for such an analysis. They also argue that the Commission's decision to defer review of the *Mobile-Sierra* protections to the compliance stage has no basis in law, explaining that the Commission is bound by law to apply the standard before abrogating any contracts. PSEG Companies state that the compliance stage is not the appropriate procedural stage to address this issue because under *Mobile-Sierra* the Commission has the burden to make its public interest finding and it is not the contracting parties' burden to defend the provisions that the Commission seeks to modify.[471]

387. Sunflower, Mid-Kansas, and Western Farmers request a partial stay of Order No. 1000's effectiveness, at least for RTOs that have limited federal rights of first refusal, if the Commission does not grant their requests for rehearing and clarification, so that RTOs are not required to remove any federal right of first refusal provisions until Order No. 1000 is final and non-appealable. They argue that it is highly likely that Order No. 1000 will be appealed and that the rehearing and appeals process may span several years. Sunflower, Mid-Kansas, and Western Farmers assert that stakeholders will be irreparably harmed if this portion of Order No. 1000 is effective before the appeals process is complete, citing the time and resources needed to modify existing tariffs and, more important, the loss of SPP transmission owners' rights that cannot be restored if the courts rule against the Commission on this issue.

(a) Commission Determination

388. The Commission affirms its decision in Order No. 1000 to address arguments that an individual contract contains a federal right of first refusal that is protected by a *Mobile-Sierra* provision when it reviews the compliance filings made by public utility transmission providers. We continue to find that the record in this rulemaking proceeding is not sufficient to address the specific issues raised regarding individual agreements. Accordingly, we reject arguments that the Commission must address in this generic rulemaking proceeding whether any particular agreement is protected by a *Mobile-Sierra* provision. Furthermore, in response to PSEG Companies, the Commission decided in Order No. 1000 when it will address the issue of whether a federal right of first refusal provision is protected by *Mobile-Sierra;* it did not and cannot shift the burden to defend such provisions to contracting parties.

389. As the Commission explained in Order No. 1000, a public utility transmission provider that considers its contract to be protected by a *Mobile-Sierra* provision may present its arguments as part of its compliance filing. We clarify, however, that any such compliance filing must include the revisions to any Commission-jurisdictional tariffs and agreements necessary to comply with Order No. 1000 as well as the *Mobile-Sierra* provision arguments. The Commission will first decide, based on a more complete record, including the viewpoints of other interested parties, whether the agreement is protected by a *Mobile-Sierra* provision, and if so, whether the Commission has met the applicable standard of review such that it can require the modification of the particular provisions.[472] If the Commission determines that the agreement is protected by a *Mobile-Sierra* provision and that it cannot meet the applicable standard of review, then the Commission will not consider whether the revisions submitted to the Commission-jurisdictional tariffs and agreements comply with Order No. 1000. However, if the Commission determines that the agreement is not protected by a *Mobile-Sierra* provision or that the Commission has met the applicable standard of review, then the Commission will decide whether the revisions to the Commission-jurisdictional tariffs and agreements comply with Order No. 1000 and, if such tariffs and agreements are accepted, would become effective consistent with the approved effective date. As a result, the Commission is not requiring public utility transmission providers to eliminate a federal right of first refusal before the Commission makes a determination regarding whether an agreement is protected by a *Mobile-Sierra* provision and whether the Commission has met the applicable standard of review, while at the same time the Commission is ensuring that the Order No. 1000 compliance process proceeds expeditiously and efficiently.

390. We also deny Sunflower, Mid-Kansas, and Western Farmers' request for a partial stay of the requirement to remove a federal right of first refusal from Commission-jurisdictional tariffs and agreements. In considering requests for a stay, the Commission has applied the standards set forth in section 705 of

Power Marketing, LLC v. *Maine PUC,* 130 S.Ct. 693 (2010)).

[469] *See, e.g.,* Sponsoring PJM Transmission Owners; Baltimore Gas & Electric; and PSEG Companies.

[470] Ameren at 16 (citing Agreement of Transmission Facilities Owners to Organize the Midwest Independent Transmission System Operator, Inc., A Delaware Non-Stock Corporation, Third Revised Rate Schedule FERC No. 1); MISO; MISO Transmission Owners Group 2.

[471] PSEG Companies at 13 (citing *Wisconsin Public Power, Inc.* v. *FERC,* 493 F.3d 239 (D.C. Cir. 2007)).

[472] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 292.

the Administrative Procedure Act,[473] and has granted a stay ''when justice so requires.'' [474] In deciding whether justice requires a stay, the Commission considers several factors, including: (1) Whether the party requesting the stay will suffer irreparable injury without a stay; (2) whether issuing the stay may substantially harm other parties; and (3) whether a stay is in the public interest.[475] The Commission's general policy is to refrain from granting stays of its orders to assure definiteness and finality in Commission proceedings.[476] If the party requesting the stay is unable to demonstrate that it will suffer irreparable harm absent a stay, the Commission need not examine the other factors.[477] As the D.C. Circuit has explained, a harm must be both certain and actual rather than theoretical, and ''mere injuries, however substantial, in terms of money, time and energy necessarily expended in the absence of a stay are not enough.''[478]

391. Sunflower, Mid-Kansas, and Western Farmers' request for stay fails to meet the first criterion, which requires it to show that it will suffer irreparable injury without a stay of the requirement to eliminate a federal right of first refusal. They argue that they must spend time and resources to modify existing tariffs. However, we find that this type of economic loss is not sufficient to warrant a stay. Furthermore, while Sunflower, Mid-Kansas and Western Farmers may lose the opportunity to exercise a federal right of first refusal, it amounts to speculation to assert that this will necessarily cause Sunflower, Mid-Kansas and Western Farmers to lose the opportunity to build a transmission project that they could have exercised a federal right of first refusal to build. They also will still have the opportunity to submit projects for evaluation and potential selection in the regional transmission plan for purposes of cost allocation as well as to build local transmission projects.[479] Thus, the harm that Sunflower, Mid-Kansas and Western Farmers argue that they will suffer is speculative because Sunflower, Mid-Kansas and Western Farmers cannot point to a specific transmission project that they will lose the right to construct and own at this time, or in the immediate future. Accordingly, we find that Sunflower, Mid-Kansas and Western Farmers have not shown that they will suffer irreparable harm absent a stay of the nonincumbent transmission developer reforms in Order No. 1000.[480]

[473] 5 U.S.C. 705 (2006).

[474] *Id.*

[475] *See, e.g., CMS Midland, Inc.,* 56 FERC ¶ 61,177 at P 61,631 (1991), *aff'd sub nom. Mich. Mun. Coop. Group* v. *FERC,* 990 F.2d 1377 (D.C. Cir.), *cert. denied,* 510 U.S. 990 (1993).

[476] *Id.*

[477] *Id.*

[478] *Wisconsin Gas Co.* v. *FERC,* 785 F.2d 699, 674 (D.C. Cir. 1985).

[479] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 318.

2. *Requirement To Remove a Federal Right of First Refusal From Commission-Jurisdictional Tariffs and Agreements, and Limits on the Applicability of That Requirement*

a. Final Rule

392. In Order No. 1000, the Commission directed public utility transmission providers to eliminate provisions in Commission-jurisdictional tariffs and agreements that establish a federal right of first refusal for an incumbent transmission provider with respect to transmission facilities selected in a regional transmission plan for purposes of cost allocation.[481] However, Order No. 1000 also limited the applicability of that elimination requirement in important ways. The Commission stated that its focus was on the set of transmission facilities that are evaluated at the regional level and selected in the regional transmission plan for purposes of cost allocation, and that it was not requiring removal from Commission-jurisdictional tariffs and agreements of federal rights of first refusal as applicable to a local transmission facility.[482] Additionally, the Commission explained that the reforms do not affect the right of an incumbent transmission provider to build, own, and recover costs for upgrades to its own transmission facilities, such as in the case of tower change outs or reconductoring, regardless of whether an upgrade has been selected in a regional transmission plan for purposes of cost allocation.[483] The Commission further noted that the reforms are not intended to alter an incumbent transmission provider's use and control of its existing rights-of-way, the retention, modification, or transfer of which remain subject to the relevant law or regulation that granted the right-of-way.[484]

[480] Moreover, though unnecessary to support our denial of this motion for stay, we note that issuing a stay here may substantially harm other parties, thereby violating the second factor the Commission considers in whether to grant a stay. As the Commission has explained, greater participation by transmission developers in the transmission planning process may lower the cost of new transmission facilities for transmission customers, enabling more efficient or cost-effective solutions to regional transmission needs. Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 291. Accordingly, because the removal of a federal right of first refusal applies only to new transmission facilities selected in a regional transmission plan for purposes of cost allocation, granting a stay of the requirement to eliminate a federal right of first refusal would delay these potential cost-saving and efficiency benefits for all entities in the region for the duration of the stay.

[481] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 313.

[482] *Id.* P 318.

[483] *Id.* P 319.

393. In a separate section of Order No. 1000, the Commission stated that for purposes of Order No. 1000, ''nonincumbent transmission developer'' refers to two categories of transmission developer: ''(1) A transmission developer that does not have a retail distribution service territory or footprint; and (2) a public utility transmission provider that proposes a transmission project outside of its existing retail distribution service territory or footprint, where it is not the incumbent for purposes of that project.'' By contrast, the Commission explained that an '''incumbent transmission developer/provider' is an entity that develops a transmission project within its own retail distribution service territory or footprint.'' [485]

394. The Commission also distinguished between a transmission facility in a regional transmission plan and a transmission facility selected in a regional transmission plan for purposes of cost allocation.[486] The Commission also defined the term ''local transmission facility,'' which it stated is a transmission facility located solely within a public utility's retail distribution service territory or footprint that is not selected in the regional transmission plan for purposes of cost allocation.[487]

b. Requests for Rehearing and Clarification

395. Several petitioners seek rehearing or clarification regarding the implementation of the removal of a federal right of first refusal for projects that are selected in the regional transmission plan for purposes of cost allocation.[488] Northern Tier Transmission Group requests that the Commission clarify the types of Commission-jurisdictional agreements that are subject to Order No. 1000's federal right of first refusal prohibition as well as the types of provisions that constitute federal rights of first refusal. Northern Tier Transmission Group asserts that these clarifications are necessary to determine which bilateral

[484] *Id.*

[485] *Id.* P 225.

[486] *Id.* PP 63–66.

[487] *Id.* PP 63–64.

[488] *See, e.g.,* Northern Tier Transmission Group; Duke; AEP; AEP; Sunflower, Mid-Kansas, and Western Farmers; and Dayton Power and Light.

agreements are affected by the rule and the types of provisions that are prohibited in future contracts. In addition, Northern Tier Transmission Group argues that the modification of bilateral agreements undermines the balance of the agreements, and therefore must be accomplished in accordance with relevant Commission precedent.

396. Some petitioners seek clarification of what Order No. 1000 intends when referring to ''nonincumbent transmission developer'' and ''incumbent transmission developer/provider.'' [489] Transmission Access Policy Study Group and APPA state that the definitions of nonincumbent transmission developer and incumbent transmission developer/provider would exclude most municipal electric systems and electric cooperatives, as well as other public power entities. For example, Transmission Access Policy Study Group and APPA argue that because most non-public utility transmission developers have retail distribution service territories, they would not qualify as nonincumbent transmission developers under the first part of the definition. They also argue that non-public utility transmission providers, as defined in section 201(f) of the FPA, are not public utilities under FPA section 201(e); thus they would not qualify as nonincumbent transmission developers under the second part of the definition. Transmission Access Policy Study Group believes that this limitation was inadvertent and that the Commission should correct this error while at the same time keeping in mind that some references to ''nonincumbent transmission developer'' may in fact be intended to apply only to jurisdictional entities.

397. APPA notes that Order No. 1000 at P 227 requires incumbent transmission developers/providers to develop a framework that includes provisions regarding how best to address participation by nonincumbent transmission developers. Therefore, APPA and Transmission Access Policy Study Group are concerned that, if non-public entities do not qualify as nonincumbent transmission developers, incumbent transmission providers will not include provisions to address their participation. Accordingly, they ask the Commission to make clear that non-public utility transmission developers can be considered nonincumbent transmission developers.

398. APPA also argues that, given these definitions, incumbent transmission developers/providers may develop a framework that prevents public power utilities from participating in joint ownership of regional transmission projects. On rehearing, APPA requests that the Commission clarify that this result was not intended and that the Commission revise the relevant definitions to allow for participation by public power entities in transmission projects.Otherwise, APPA requests rehearing of this issue on the grounds that the definitions are unduly discriminatory as applied to public power utilities and preferential as applied to public utilities and other for-profit entities, in violation of sections 205 and 206 of the FPA.

399. Some petitioners seek guidance or clarification regarding the term ''footprint'' as it is used in the definitions of a ''local transmission facility'' and ''incumbent transmission developer.'' [490] American Transmission and ITC Companies interpret the term footprint to be directed at entities, such as transmission-only companies, that do not have retail distribution service territories, and thus expands the definitions of an incumbent and a local transmission facility instead of further defining retail distribution service territory. If the Commission instead clarifies that the term is intended to further define retail distribution service territory, then American Transmission seeks rehearing of the definition of incumbent transmission developer, arguing that it is arbitrary and capricious and discriminatory to exclude transmission-only companies from the definition.It argues that it should be considered an incumbent because it is subject to the mandatory NERC reliability standards for its facilities. As for the definition of a local transmission facility, ITC Companies state that they have no local transmission plans and that all transmission projects they propose are evaluated and included under the MISO or SPP Transmission Expansion Plans and are not ''merely rolled up.'' However, ITC Companies state that these projects may be located solely within the footprint of one or more of the ITC Companies.

400. Wisconsin PSC adds that American Transmission, for example, is effectively an incumbent transmission provider with a footprint equivalent to the aggregate franchise territories of its wholesale load-serving entity customers. Wisconsin PSC asserts that categorizing American Transmission as a nonincumbent transmission developer would treat it as a merchant transmission developer in its home territory of the last ten years and compel it to double up on the essentially local planning processes as if it was a merchant, even though it currently conducts regional planning in coordination with MISO's regional planning.Wisconsin PSC asserts that the extra costs from such duplicative planning would be unjust and unreasonable and therefore it requests that the Commission clarify the categorization of nonincumbent transmission developer to exclude transmission-only entities.

401. Duke seeks confirmation that a nonincumbent transmission developer either becomes an incumbent transmission developer/provider when its project is energized, if not sooner, or that the provisions of paragraph 319 of Order No. 1000, relating to upgrades and use of rights-of-way, apply to nonincumbents that construct projects. Also, according to Duke, the term ''retail distribution,'' as used in the definitions of nonincumbent transmission developer and incumbent transmission developer/provider, modifies ''service territory'' but not ''footprint.''Thus, Duke contends that, under this interpretation, the nonincumbent developer of an actual project will eventually have a footprint and thus become an incumbent as to that limited footprint. However, if the Commission clarifies that nonincumbents never become incumbents, then it requests that the Commission nonetheless grant nonincumbents the same rights described in paragraph 319 of Order No. 1000 as to its own facilities and rights of way and describe when those rights would exist. It recommends that a nonincumbent obtains a federal right of first refusal no later than energization of its facilities.At a minimum, Duke requests detailed clarification on this issue so as to avoid litigation on compliance.

402. Edison Electric Institute seeks clarification that public utility transmission providers constructing new facilities in their ''footprint'' pursuant to service obligations imposed on them under federal, state, or local law or under long-term contracts are included in the definition of incumbent transmission providers. It notes that some transmission facility-owning public utilities may lack a retail distribution service territory, and that other transmission facility-owning public utilities with retail distribution service territories may need to construct new transmission facilities that are not fully contained within those retail

[489] *See, e.g.,* Transmission Access Policy Study Group; and APPA.

[490] *See, e.g.,* ITC Companies; LS Power; American Transmission; Wisconsin PSC; and Edison Electric Institute.

distribution territories. Thus, it seeks clarification that both kinds of transmission facility-owning public utilities continue to have the same right to construct reliability projects not subject to regional cost allocation where necessary to meet their reliability needs or service obligations. It also seeks confirmation that the use of the term ''footprint'' is intended to capture new facility construction that may be separate from a retail distribution service territory but is nonetheless being constructed by an incumbent transmission owning utility to meet reliability or service obligation needs, adding that this clarification would tie the right of an incumbent transmission provider to choose to build facilities not submitted for regional cost allocation to the existence of a service obligation under federal, state, or local law or under long-term contracts. To the extent that the Commission intended to grant this right in favor of some public utility transmission provider service obligations and not others, Edison Electric Institute argues that the Commission is required to explain and justify its decision.

403. Other petitioners request clarification or rehearing as to how to determine whether a project is considered a regional or local project.[491] For instance, LS Power requests clarification of how the Commission intends to apply this local exemption. LS Power states that the Commission did not explain how a footprint might differ from a retail distribution area, which may have a different meaning in different states. Also, LS Power states that while a retail distribution area is a familiar concept, it does not provide a geographic-based definition.For example, a utility may own a transmission line that geographically extends beyond its retail service area that it may believe should be part of its footprint, but that line may cross into another transmission provider's geographical retail distribution area which the other transmission provider considers to be part of its footprint. LS Power also states that joint ownership of a substation or transmission line is common, where several entities all have rights to use the capacity of the line. LS Power also claims that it is unclear how this definition would be applied in the context of an RTO, where the transmission provider's footprint covers the entire region.

404. Accordingly, LS Power requests clarification that within and outside an RTO, a ''local transmission facility'' is one that is located within the geographical boundaries of the retail distribution service territory served by the public utility transmission provider as of the effective date of Order No. 1000 and interconnecting solely to the public utility transmission provider's existing facilities. LS Power continues that where there are affiliated public utility transmission providers located in adjacent and electrically connected geographic areas, they may be treated as a single transmission owner only if, as of the date Order No. 1000 became effective, the affiliates have, in the past, conducted joint planning and maintained a single transmission rate applicable to service provided by all such affiliates regardless of the customer's location within the retail distribution area of a single affiliate and, where located in a RTO, proffered a single local plan to the RTO and participated in RTO affairs as a single transmission owner (e.g., voting rights under all jurisdictional agreements). LS Power further states that any projects connecting, in whole or in part, to facilities owned by another transmission owner or to jointly owned facilities would not constitute local facilities. Last, it argues that ''local'' should be defined as of the effective date of Order No. 1000, because the area in which an incumbent transmission owner can claim an exemption to the elimination of the federal right of first refusal should not be the subject of corporate structuring.

405. Duke asserts that the primary difficulty in differentiating regional and local projects is that there are many ways to interpret the phrase ''transmission facilities selected in a regional transmission plan for purposes of cost allocation.'' According to Duke, many RTOs have adopted cost allocation approaches for all types of projects and that even local projects ultimately are included in the ''regional plan.'' In addition, Duke asserts that a pricing zone that consists of the retail distribution service territory of a single load-serving entity that was also a transmission provider is an anomaly, and that it is more likely that a typical pricing zone will consist of a public utility transmission provider and more than one retail load-serving entity with a service territory, such as, for instance, a non-jurisdictional distribution and/or transmission company. Accordingly, Duke seeks clarification that, under a zonal approach to cost allocation, a facility whose costs are allocated under an RTO tariff to a single RTO pricing zone, and which is located in that pricing zone, be deemed a local facility.

406. Duke also adds that, under a non-RTO model or dominant provider model, all the load in a single zone would be network load of the public utility transmission provider, with any other transmission owners receiving credits for their integrated transmission facilities. Accordingly, Duke requests clarification that the Commission intended that single zone facilities may be classified as local facilities, as long as the general construct under a non-RTO model, or dominant provider model, is met. Duke adds that any proposals for 're-zoning' meant to evade the impact of the removal of a federal right of first refusal can be addressed on compliance. If the Commission clarifies that a single zone facility under no circumstances can be a local facility, then Duke asserts that the Commission would effectively obliterate the federal right of first refusal in virtually every ISO and RTO, which could cause significant exoduses from ISOs and RTOs or cause ISOs and RTOs to completely overhaul their entire cost allocation processes.

407. Petitioners also seek clarification that a project that is selected in the plan, but for which the costs are assigned to a single utility, is considered a local facility for purposes of the applicability of the requirement to remove the federal right of first refusal.[492] Specifically, Duke asks whether the focus is on the result of a cost allocation method or the area over which the method is applied such as an entire region. Duke urges the Commission to adopt the results approach, and clarify that if any cost allocation approach results in a single zone being allocated the costs of a facility, then an RTO should be permitted to deem the facility as local and therefore, apply a federal right of first refusal. Duke seeks clarification that facilities that have any costs allocated outside a single zone, even if such facilities are physically in a single zone, will be presumed to be regional, unless they are an upgrade to existing facilities.

408. Dayton Power and Light also asserts that the Commission should clarify that when all of a facility's costs are assigned to a single utility zone, the tariff could continue to permit a federal right of first refusal. However, Dayton Power and Light also seeks clarification as to whether a facility that is allocated solely to one utility zone using a regional cost allocation method should be treated differently for purposes of a federal right of first refusal from a facility that is allocated predominately to one utility zone, and if so, where the break-point should be. Sunflower, Mid-

[491] *See, e.g.,* Duke; and AEP.

[492] *See, e.g.,* Duke; AEP; and Dayton Power and Light.

Kansas, and Western Farmers seek clarification (or, alternatively, rehearing) that the definition of ''regionally funded'' excludes projects where costs allocated to a region are not at least a majority of the total costs.

409. In addition, ITC Companies and Xcel request clarification of ''selected in a regional transmission plan for purposes of cost allocation'' as it applies to the transmission facilities that are approved by MISO under its MISO Transmission Expansion Plan or by SPP under its SPP Transmission Expansion Plan.[493] Xcel states that Order No. 1000 creates ambiguity by assuming that the cost allocation for local zone projects, such as in MISO and SPP, is not identified in the regional RTO tariff process.[494] Xcel states that it believes that, under Order No. 1000, the costs for a project selected in the MTEP or STEP may permissibly be assigned to a single zone, whether that zone includes the facilities of a single transmission owner or whether a transmission owner has facilities that are included in other zones, through a regional cost allocation method, and that such an allocation is not precluded by Order No. 1000.

410. ITC Companies argue that MISO cost allocation methods fall along a continuum that on one end includes 100 percent allocation on a systemwide basis for multi-value projects, and on the other end are participant funded projects assumed by project sponsors. They state that in SPP 100 percent of the costs of Base Plan Upgrades 300kV and above are allocated to a regionwide annual transmission revenue requirement and recovered through a regionwide charge. They thus assert that it is unclear whether certain projects would be considered ''transmission facilities selected * * * for purposes of cost allocation'' under Order No. 1000.[495] ITC Companies request clarification that this term means those projects approved in a regional transmission plan and which are also approved for 100 percent regional cost allocation.They argue that if the Commission does not clarify this term, if a project becomes ineligible for federal rights of first refusal when any of the costs of that project are borne by customers beyond the local zone or footprint in which that project is located, the construction of more efficient, cost-effective multi-purpose projects with broad regional benefits will be discouraged. They maintain that incumbent transmission owners will oppose projects with broader benefits in favor of less efficient projects for which their rights of first refusal are preserved. They assert that projects will be designed to avoid minor enhancements that would benefit a region, but which would not justify a stand-alone, purely economic project.

411. On the other hand, Western Independent Transmission Group argues that the Commission failed to provide a reasoned explanation of why it did not remove the federal right of first refusal for local transmission facilities, and why it is not unduly discriminatory or preferential to uphold the federal right of first refusal for facilities not in a plan for purposes of cost allocation. Western Independent Transmission Group also argues that Order No. 1000 did not address in adequate detail the boundary between transmission projects for which independent transmission developers have a right to compete, and those projects that are reserved solely to the incumbent transmission provider. According to Western Independent Transmission Group, the most obvious instance where the Commission's failure to address the subject may have significant competitive impacts on transmission planning is the distinction between public policy projects and transmission projects initiated through the generation interconnection process. Western Independent Transmission Group argues that, particularly in California, where the vast majority of approved transmission projects in the most recent 2010/2011 planning cycle were initiated through the generator interconnection process, the Commission's unwillingness to address this issue effectively left incumbent utilities with a total monopoly over the transmission built in response to renewable energy development.

412. Petitioners also seek clarification of what is to be considered an upgrade to an existing transmission facility such that the elimination of the federal right of first refusal does not apply. For example, Duke seeks clarification that if an incumbent transmission owner cuts into its own existing transmission line to construct a new 345 kV substation that is needed for stability due to local growth on its system, such a substation, even if a share of its costs are allocated to all pricing zones in a region, would be covered by the federal right of first refusal under the ''upgrades to its own transmission facilities'' carve out. If not, then Duke asserts that a region should be able to take this policy into account in implementing Order No. 1000, such that a region could alter its cost allocation method so that the type of project described above is not subject to any regional cost allocation if the region decides such projects merit a federal right of first refusal.

413. Similarly, ITC Companies seek clarification that the prohibition on a federal right of first refusal does not apply to a transmission upgrade that requires expansion of an existing right-of-way in order to be expanded. ITC Companies argue that retaining a federal right of first refusal for upgrades that require an expansion of an existing right of way is necessary to avoid unintended and adverse consequences that would undermine the optimal and cost-effective development of the grid.

414. Finally, petitioners also request rehearing of the Commission's decision to eliminate incumbent utility transmission providers' existing rights to construct reliability projects.[496] Xcel believes that incumbent transmission providers, particularly franchised utilities with an obligation to serve, should retain the right to construct transmission projects necessary for the utility to provide reliable service to their native load customers and to comply with NERC mandatory reliability standards. Xcel asserts that this federal right of first refusal does not need to be unlimited and supports the inclusion of a 90-day election period during which the incumbent transmission provider would be required to indicate its decision to move forward with the designated project. Xcel contends that the Commission's attempt to address utility providers' concerns by eliminating certain penalty responsibilities fails to recognize that utilities have an obligation to serve and are not merely worried about financial penalties.

c. Commission Determination

415. We affirm the decision in Order No. 1000 to require the elimination of a federal right of first refusal from Commission-jurisdictional tariffs and agreements for transmission facilities selected in a regional transmission plan for purposes of cost allocation. In response to Northern Tier Transmission Group, the phrase ''a federal right of first refusal'' refers only to rights of first refusal that are created by provisions in

[493] ITC Companies; Xcel at 20 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at n.299).

[494] Xcel at 20 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at n.299).

[495] ITC Companies specifically ask about the following: (1) MISO Baseline Reliability Projects eligible for 20 percent regional cost allocation but whose costs can be 100 percent allocated to the host zone pursuant to power flow modeling; (2) MISO Market Efficiency Projects eligible for 20 percent regional cost allocation; and (3) SPP Base Plan Upgrades eligible for 33 percent regional cost allocation.

[496] *See, e.g.,* Xcel; and Edison Electric Institute.

Commission-jurisdictional tariffs or agreements.[497]

416. In response to petitioners' concerns, we also clarify several of the terms used in Order No. 1000, starting with the term ''nonincumbent transmission developer.'' In doing so, we first affirm the definition of incumbent transmission developer/provider as ''an entity that develops a transmission project within its own retail distribution service territory or footprint.'' [498] Given this definition, we clarify that a ''nonincumbent transmission developer'' is any entity that is not an incumbent transmission developer/provider. We believe that this clarification, along with the others made in this order, addresses the concerns expressed by Transmission Access Policy Study Group and APPA that the definitions of nonincumbent transmission developer and incumbent transmission developer/provider in Order No. 1000 would exclude certain municipal electric systems and electric cooperatives, as well as other public power entities.

417. However, as discussed more fully below, we find that in order for a non-public utility to be considered a nonincumbent transmission developer, it must satisfy the enrollment requirement if it or an affiliate has load in the transmission planning region where it proposes a transmission project for selection in the regional transmission plan for purposes of cost allocation as would any other potential transmission developer.[499] As an initial matter, we note that the Commission did not intend through its definition of nonincumbent transmission developer in Order No. 1000 to exclude any transmission developer, including a non-public utility transmission developer, from being able to propose transmission projects and have them evaluated and selected by a regional transmission planning process for purposes of cost allocation, so long as that transmission developer abides by the same requirements as those imposed on public utility transmission providers. Allowing entities, such as non-public utility transmission developers, the opportunity to potentially propose a transmission project as a nonincumbent transmission developer furthers the Commission's goal in Order No. 1000 of ensuring that all transmission developers have a comparable opportunity to incumbent transmission developers/providers to propose a transmission project for selection in the regional transmission plan for purposes of cost allocation.

418. However, we also recognize that it would be fundamentally unfair and thereby may lead to an unjust and unreasonable or unduly discriminatory or preferential result to allow a transmission developer, whether it is a public utility transmission developer or a non-public utility transmission developer, to seek regional cost allocation for a proposed transmission project in a transmission planning region in which it or an affiliate has load, but where neither it, nor that affiliate, has enrolled in that region where its load is located. Such a result would permit a transmission developer to allocate the costs of its project to other entities in the region pursuant to that region's cost allocation method—without first enrolling itself or its affiliate in the transmission planning region in which its load is located and potentially being allocated costs for other transmission projects for which it is found to be a beneficiary.[500]

419. Therefore, Order No. 1000's reforms regarding the submission and evaluation of proposals for potential selection in a regional transmission plan for purposes of cost allocation will apply to a transmission developer that has load or an affiliate within an area that would normally be considered a geographic part of a transmission planning region if the transmission developer or its affiliate transmission provider in that area enrolls in the transmission planning region in which that load is located. We believe that in most cases, it should be clear where an entity's load is located and therefore the region in which it would be expected to enroll. However, should disputes arise over the choice of a region, we will address them on a case-by-case basis utilizing the standard found in Order No. 890 and Order No. 1000, which provides that ''the scope of a transmission planning region should be governed by the integrated nature of the regional power grid and the particular reliability and resource issues affecting individual regions.'' [501] We emphasize that an entity, including a non-public utility transmission developer, that does not have load within a transmission planning region may propose a transmission project for evaluation and potential selection in that region's transmission plan for purposes of cost allocation without enrolling in that region, as long as it satisfies the transmission planning region's other requirements for doing so, such as meeting the qualification criteria for proposing projects found in Order No. 1000.

420. Turning to other terms used in Order No. 1000, we also clarify that the phrase ''retail distribution,'' as used in the definitions of incumbent transmission developer/provider, nonincumbent transmission developer and local transmission facility, does not modify footprint. Instead, the term ''footprint,'' as used in these definitions was intended to include, but not be limited to, the location of the transmission facilities of a transmission-only company that owns and/or controls the transmission facilities of formerly vertically-integrated utilities, as well as the location of the transmission facilities of any other transmission-only company.

421. In response to Duke, we agree that a nonincumbent transmission developer will have a footprint at the time that its transmission facility is energized. As such, we clarify that a nonincumbent transmission developer will then become an incumbent transmission developer/provider for that energized transmission facility and will thereafter have all the rights and obligations that accrue to such entities under Order No. 1000, such as being able to maintain a federal right of first refusal for local transmission facilities and upgrades to those transmission facilities.

422. In response to Edison Electric Institute, we note that there are a great variety of fact patterns that may fall under its request. For example, Edison Electric Institute does not explain whether the new transmission facility would go through the retail distribution service territory of the incumbent transmission owning utility, that of another entity, or an ''unassigned'' territory. Thus, we decline to find generically that any particular transmission facility, whether it is needed to meet a reliability, economic, or transmission need driven by a Public Policy Requirement, developed outside of an *existing* retail distribution service territory or footprint, should be considered a part of that entity's footprint.

[497] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 253 n.231.

[498] *Id.* P 225.

[499] We refer to non-public utility entities that seek to propose projects in a regional transmission planning process as ''non-public utility transmission developers,'' which may include both non-public utility transmission providers that already own and operate transmission facilities and transmission-dependent non-public utilities that may wish to develop, construct, or own transmission facilities in the future.

[500] For discussion of enrolling in a transmission planning region, see the Regional Transmission Planning Requirements section. *See* discussion *supra* at section III.A.2.c.

[501] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 160 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 527).

423. We clarify that Order No. 1000 does not require elimination of a federal right of first refusal for a new transmission facility if the regional cost allocation method results in 100% of the facility's cost being allocated to the public utility transmission provider in whose retail distribution service territory or footprint the facility is to be located. Accordingly, we clarify that the term ''selected in a regional transmission plan for purposes of cost allocation'' excludes a new transmission facility if the costs of that facility are borne entirely by the public utility transmission provider in whose retail distribution service territory or footprint that new transmission facility is to be located. Although public utility transmission providers in a transmission planning region may determine, based on non-discriminatory evaluation criteria, that a proposed transmission facility is likely to have regional benefits so that the transmission facility's costs should be allocated regionally, it is not until the cost allocation method is applied that the beneficiaries are identified.

424. Petitioners request clarification about whether a transmission facility is a local transmission facility if it is selected in a regional transmission plan for purposes of cost allocation and the costs are allocated to a single pricing zone in which the proposed transmission facility is to be located, and that zone consists of more than one transmission provider. In general, any regional allocation of the cost of a new transmission facility outside a single transmission provider's retail distribution service territory or footprint, including an allocation to a ''zone'' consisting of more than one transmission provider, is an application of the regional cost allocation method and that new transmission facility is not a local transmission facility. For example, transmission-owning members of an RTO may not retain a federal right of first refusal by dividing the RTO into East and West multi-utility zones and allocating costs just within one zone consisting of more than one transmission provider. However, we recognize in response to Duke's request that special consideration is needed when a small transmission provider is located within the footprint of another transmission provider. For instance, a regional cost allocation method might allocate costs to an area consisting of one transmission provider that has within its borders one or more smaller utilities that largely depend on its transmission system but nevertheless own a little transmission of their own, so that they too are transmission providers. This situation is not necessarily ''a zone consisting of more than one transmission provider'' as this term is used in this order. If the cost of a new transmission facility is allocated entirely to an area consisting of one transmission provider that has one or more smaller transmission providers within its borders, this might qualify as a local cost allocation, not a regional cost allocation. However, as petitioners point out, there may be a continuum of examples that range from (i) one small municipality with a single small transmission facility located within a transmission provider's footprint, to (ii) a ''zone'' consisting of many public utility and nonpublic utility transmission providers. Accordingly, we will address whether a cost allocation to a multi-transmission provider zone is regional on a case-by-case basis based on the specific facts presented. Specific situations may be included in a compliance filing along with the filed regional cost allocation method or methods.

425. We disagree with Western Independent Transmission Group's assertion that the Commission failed to provide a reasoned explanation of its decision not to require the elimination of a federal right of first refusal for local transmission facilities. In Order No. 1000, the Commission recognized that incumbent transmission providers may have reliability needs or service obligations.[502] Accordingly, Order No. 1000 does not prevent an incumbent transmission provider from meeting its reliability needs or service obligations by choosing to build new transmission facilities that are located solely within its retail distribution service territory or footprint and that are not selected in a regional transmission plan for purposes of cost allocation.[503] Thus, we affirm the decision in Order No. 1000 not to require elimination from Commission-jurisdictional tariffs and agreements a federal right of first for a local transmission facility.[504] We also note in response to Western Independent Transmission Group that the Commission found that issues related to the generator interconnection process and to interconnection cost recovery were outside the scope of Order No. 1000.[505] Order No. 1000 did not establish any new requirements with respect to the generator interconnection process, and we are not persuaded to address the generator interconnection process on rehearing.

426. In response to requests for clarification regarding what the Commission considers to be an upgrade, we note that in Order No. 1000, the term upgrade means an improvement to, addition to, or replacement of a part of, an existing transmission facility. The term upgrades does not refer to an entirely new transmission facility. The concept is that there should not be a federally established monopoly over the development of an entirely new transmission facility that is selected in a regional transmission plan for purposes of cost allocation to others. However, neither is the Commission eliminating the right of an owner of a transmission facility to improve its own existing transmission facility by allowing a third-party transmission developer to, for example, propose to replace the towers or the conductors of a transmission line owned by another entity.[506] It is not feasible, however, to list every type of improvement or addition, or name all the parts of lines, towers and other equipment that may be replaced or otherwise upgrades, and we will not do so here.

427. In response to ITC Companies, we clarify that the requirement to eliminate a federal right of first refusal does not apply to any upgrade, even where the upgrade requires the expansion of an existing right-of-way. The issue is not whether the upgrade would be located in an existing right-of-way, but whether the new transmission facility is an upgrade to an incumbent transmission provider's own facilities. Furthermore, the Commission reiterates that the nonincumbent transmission developer reforms were not intended to alter an incumbent transmission provider's use and control of its existing rights-of-way under state law.[507]

428. We affirm the decision in Order No. 1000 to require the elimination of a federal right of first refusal for reliability projects. Allowing incumbent transmission providers to maintain a federal right of first refusal, even with a limited 90-day election period as proposed by Xcel, would discourage

[502] *Id.* P 262. The Commission defined a local transmission facility as a transmission facility located solely within a public utility transmission provider's retail distribution service territory or footprint that is not selected in a regional transmission plan for purposes of cost allocation. An incumbent transmission provider would retain the option of meeting its local reliability needs or obligations to serve by building a transmission facility in its retail distribution service territory or footprint. *Id.* at P 63.

[503] *Id.* In P 262 of Order No. 1000, the Commission used the term ''submitted for regional cost allocation'' where we intended ''selected in a regional transmission plan for purposes of cost allocation.'' We provide that clarification here.

[504] *Id.* P 318.

[505] *Id.* P 760.

[506] *Id.* P 319.

[507] *Id.*

transmission developers from proposing transmission projects that may be a more efficient or cost-effective solution to meet regional transmission needs, resulting in rates for jurisdictional transmission services that are unjust and unreasonable or unduly discriminatory or preferential. The fact that a particular transmission facility is intended to meet a reliability need does not change our responsibility to eliminate practices that result in unjust and unreasonable or unduly discriminatory or preferential rates. Furthermore, Order No. 1000 includes several reforms that ensure that incumbent transmission providers will be able to satisfy their reliability needs and service obligations, even when they are relying on a nonincumbent transmission developer's project to meet a reliability need. Specifically, Order No. 1000 includes a reevaluation requirement that requires public utility transmission providers in a region to have procedures in place to identify when delays in the development of a transmission facility selected in a regional transmission plan for purposes of cost allocation require evaluation of alternative solutions to ensure that an incumbent transmission provider can meets its reliability needs or service obligations.[508] Moreover, we note again that Order No. 1000 continues to permit an incumbent transmission provider to meet its reliability needs or service obligations by choosing to build new transmission facilities that are located solely within its retail distribution service territory or footprint and that are not selected in a regional transmission plan for purposes of cost allocation.[509] Accordingly, we disagree with petitioners that argue that a federal right of first refusal for reliability project is necessary for incumbent transmission providers to meet reliability needs or service obligations.

429. In response to LS Power's concerns regarding the definition of a local transmission facility, we clarify that a local transmission facility is one that is located within the geographical boundaries of a public utility transmission provider's retail distribution service territory, if it has one, otherwise the area is defined by the public utility transmission provider's footprint. Thus, if the public utility transmission provider has a retail distribution service territory and/or footprint, then only a transmission facility that it decides to build within that retail distribution service territory or footprint, and that is not selected in a regional transmission plan for purposes of cost allocation, may be considered a local transmission facility. In the case of an RTO or ISO whose footprint covers the entire region, we clarify that local transmission facilities are defined by reference to the retail distribution service territories or footprints of its underlying transmission owing members. We also clarify that the extent of a public utility transmission provider's retail distribution service territory or footprint is not to be measured as of the effective date of Order No. 1000, but is the retail distribution service territory or footprint in existence during the regional transmission planning cycle. We decline to provide any of the further clarifications regarding the definition of a local transmission facility as requested by LS Power and will address such matters during the compliance process based on a more complete record.

430. Finally, in response to petitioners' concerns over which facilities are selected in a regional transmission plan for purposes of cost allocation, and for which a federal right of first refusal must therefore be eliminated, we clarify that if any costs of a new transmission facility are allocated regionally or outside of a public utility transmission provider's retail distribution service territory or footprint, then there can be no federal right of first refusal associated with such transmission facility, except as provided in this order.

3. Framework To Evaluate Transmission Projects Submitted for Selection in the Regional Plan for Purposes of Cost Allocation

431. In Order No. 1000, the Commission required each public utility transmission provider to revise its OATT to describe the features of an acceptable framework for project identification and selection. The Commission required that this framework include: (1) Qualification criteria to submit a transmission project for selection in the regional transmission plan for purposes of cost allocation; (2) specification of the information that must be submitted by a prospective transmission developer in support of the transmission project it proposes in the regional transmission planning process and the date by which such information must be submitted to be considered in a given transmission planning cycle; (3) a description of a transparent and not unduly discriminatory process for evaluating whether to select a proposed transmission facility in the regional transmission plan for purposes of cost allocation; and (4) provisions allowing a nonincumbent transmission developer to have the same eligibility as an incumbent transmission provider to use a regional cost allocation method or methods for any sponsored transmission facility selected in the regional transmission plan for purposes of cost allocation. Last, the Commission declined to require public utility transmission providers to revise their OATTs to provide a transmission developer a right to construct and own a transmission facility and also declined to allow a transmission developer to maintain for a defined period of time its right to build and own a transmission project that it proposed but that is not selected.[510]

a. Qualification Criteria To Submit a Transmission Project for Selection in the Regional Transmission Plan for Purposes of Cost Allocation

i. Final Rule

432. The Commission required each public utility transmission provider to revise its OATT to demonstrate that the regional transmission planning process in which it participates has established qualification criteria that are not unduly discriminatory or preferential for determining an entity's eligibility to propose a transmission project for selection in the regional transmission plan for purposes of cost allocation, whether that entity is an incumbent transmission provider or a nonincumbent transmission developer.[511] The Commission explained that the criteria must provide each potential transmission developer the opportunity to demonstrate that it has the necessary financial resources and technical expertise to develop, construct, own, operate, and maintain transmission facilities.[512] The Commission found that one-size-fits-all qualification criteria would not be appropriate, and that it is important for each transmission planning region to have the flexibility to formulate qualification criteria that best fits its transmission planning processes and addresses the particular needs of the region, so long as the criteria are fair and not unreasonably stringent when applied to either the incumbent transmission provider or a nonincumbent transmission developer.[513]

[508] *Id.* P 329.

[509] *Id.* P 262.

[510] *Id.* PP 323–40.

[511] *Id.* P 323.

[512] *Id.*

[513] *Id.* P 324.

ii. Requests for Rehearing and Clarification

433. Several petitioners seek rehearing of the Commission's requirement that the regional planning process develop qualification criteria.[514] They assert that Order No. 1000 creates an unreasonable disparity between who establishes the criteria for a nonincumbent to be deemed qualified to propose and construct a transmission project and who bears the risk if such nonincumbent does not perform.[515] They state that each incumbent transmission provider remains responsible for meeting its reliability and system security obligations in the event that the nonincumbent fails to perform, but must rely on qualification criteria developed by the region planning process. They state that this disparity is unreasonable, arbitrary and capricious, and should be revised to be more consistent with the model provided for in Order No. 890–A, which allows the transmission provider to establish reasonable credit criteria.[516] They also believe this would allow each incumbent transmission provider that bears the greatest risk of non-performance of a nonincumbent to better manage such risk.[517]

434. Other petitioners request that the Commission standardize the qualification criteria or otherwise clarify that certain criteria are impermissible.[518] NextEra argues that there should be a standardized qualification requirement rather than the flexible approach adopted in Order No. 1000 because it believes that such flexibility could permit incumbents to devise qualification criteria that create barriers to entry. NextEra states that, unlike other areas of Order No. 1000 that endorse flexibility, there is no reason to believe that financial and technical qualification criteria for new transmission entrants should vary by region. NextEra points to the Commission's actions in standardizing generator interconnection procedures under Order No. 2003 and credit reform rules under Order No. 741. NextEra also suggests that the Commission look to the qualification criteria established by ERCOT and CAISO as examples. Alternatively, NextEra states that the Commission should initiate a negotiated rulemaking to develop consensus criteria, which it states is the course the Commission followed in developing Order No. 2003.

435. LS Power requests that the Commission clarify that the qualification criteria for entities that want to propose a project in the regional transmission planning process are limited to financial and technical matters. It also asks that the qualification criteria not operate as a barrier to entry and should not include a qualification that a new entrant be an existing public utility under state law or have upfront siting authority. It contends that a new entrant would not be able to achieve state public utility status at the assignment stage because it is most often granted after the assignment of the transmission project. LS Power similarly argues that the selection criteria used to evaluate a project also should not require that a project sponsor be an existing public utility under state law or have upfront siting authority before it can be assigned a project. LS Power contends that such selection criteria would also act as a barrier to entry in that states most often grant public utility status and eminent domain authority after the assignment of the transmission project.

436. APPA requests that the Commission require that the minimum participation criteria developed by incumbent transmission developers/providers be fair and not unreasonably stringent as applied to public power utilities.

437. Transmission Access Policy Study Group seeks clarification that the qualification criteria facilitate transmission dependent utility joint ownership, and states that qualification criteria designed for proposals submitted by a single entity could unintentionally and needlessly foreclose beneficial project participation by multiple joint owners.

438. New York Transmission Owners request that transmission planning regions be permitted to require NERC registration for nonincumbent transmission developers as a precondition to being assigned a reliability project.

iii. Commission Determination

439. We affirm Order No. 1000's requirement that the public utility transmission providers in each transmission planning region must establish, in consultation with stakeholders, appropriate qualification criteria for determining an entity's eligibility to propose a transmission project for selection in the regional transmission plan for purposes of cost allocation. As required under Order No. 1000, these qualification criteria must not be unduly discriminatory or preferential and must provide each potential transmission developer the opportunity to demonstrate that it has the necessary financial resources and technical expertise to develop, construct, own, operate, and maintain transmission facilities.[519] We disagree with petitioners that this approach creates an unreasonable disparity between who establishes the criteria for a nonincumbent transmission developer to be deemed qualified to propose and construct a transmission project and who bears the risk if such nonincumbent transmission developer does not perform. Order No. 1000 makes clear that it is public utility transmission providers themselves, in consultation with stakeholders, that are responsible for complying with Order No. 1000 and that must develop the qualification criteria for review by the Commission on compliance.[520]

440. The Commission declines to adopt standardized qualification criteria, as urged by NextEra. While the Commission's acknowledges NextEra's concern that qualification criteria could act as a barrier to entry, the Commission believes that there may be legitimate differences between regions that may justify differences in the qualification criteria. Each region is faced with its own set of challenges in building new transmission facilities, and regions should be permitted to account for those differences in their qualification criteria. For this same reason, the Commission will not adopt certain minimum qualification criteria. Regarding LS Power's petition that the qualification criteria be limited to financial and technical matters, we point out that Order No. 1000 states that ''[t]he qualification criteria must provide each potential transmission developer the opportunity to demonstrate that it has the necessary financial resources and technical expertise to develop,

[514] *See, e.g.,* Ad Hoc Coalition of Southeastern Utilities; and Southern Companies.

[515] *See, e.g.,* Ad Hoc Coalition of Southeastern Utilities; and Southern Companies.

[516] Ad Hoc Coalition of Southeastern Utilities at 62 (citing Order No. 890–A, Attachment L (Creditworthiness Procedures) to Pro Forma OATT; Order No. 890 at P 1659); Southern Companies at 63 (citing *Preventing Undue Discrimination and Preference in Transmission Serv.,* Order No. 890–A, 121 FERC ¶ 61,297, Attachment L (2007)).

[517] *See, e.g.,* Ad Hoc Coalition of Southeastern Utilities; and Southern Companies.

[518] *See, e.g.,* NextEra; LS Power; and New York Transmission Owners.

[519] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 323.

[520] We reiterate that ''the qualification criteria required [in Order No. 1000] should not be applied to an entity proposing a transmission project for consideration in the regional transmission planning process if that entity does not intend to develop the proposed transmission project. The Order No. 890 transmission planning requirements allow any stakeholder to request that the transmission provider perform an economic planning study or otherwise suggest consideration of a particular transmission solution in the regional transmission planning process.'' *Id.* P 324 n.304.

construct, own, operate and maintain transmission facilities,'' but also permits each transmission planning region flexibility to formulate qualification criteria that best fit its transmission planning processes and addresses the particular needs of the region.[521]

441. We clarify in response to LS Power that it would be an impermissible barrier to entry to require, as part of the qualification criteria, that a transmission developer demonstrate that it either has, or can obtain, state approvals necessary to operate in a state, including state public utility status and the right to eminent domain, to be eligible to propose a transmission facility. As the Commission emphasized in Order No. 1000, and reiterates here, the qualification criteria must be fair and not unreasonably stringent when applied to an incumbent transmission provider and a nonincumbent transmission developer.[522] The Commission will review on compliance whether any proposed qualification criterion is unreasonably stringent when applied to nonincumbent transmission developers such that the criteria act as an unreasonable barrier to entry.[523]

442. If a transmission facility is selected in the regional transmission plan for purposes of cost allocation, the Commission clarifies that the transmission developer of that transmission facility must submit a development schedule that indicates the required steps, such as the granting of state approvals, necessary to develop and construct the transmission facility such that it meets the transmission needs of the region. As part of the ongoing monitoring of the progress of the transmission project once it is selected, the public utility transmission providers in a transmission planning region must establish a date by which state approvals to construct must have been achieved that is tied to when construction must begin to timely meet the need that the project is selected to address. If such critical steps have not been achieved by that date, then the public utility transmission providers in a transmission planning region may remove the transmission project from the selected category and proceed with reevaluating the regional transmission plan to seek an alternative solution.

443. We believe that there are a number of benefits to this approach. First, it ensures that transmission developers that have the technical and financial capability to build a transmission facility, and meet other nondiscriminatory and non-preferential criteria, are eligible to propose a transmission facility for evaluation and selection, thereby increasing the universe of potential facilities evaluated and selected to meet a region's transmission needs. Second, it gives a nonincumbent transmission developer the opportunity to propose a transmission facility while it seeks to obtain necessary state approvals or otherwise seeks to comply with applicable state law or regulation. Third, it provides the public utility transmission providers in a transmission planning region with the ability to monitor the development of a transmission facility selected in the regional transmission plan for purposes of cost allocation, as well as the ability to remove that new transmission facility if its developer is unable to meet an established date by which the critical development step of obtaining necessary state approvals must be achieved.

444. We also deny New York Transmission Owners' request that the public utility transmission providers in a transmission planning region be permitted to require a transmission developer to demonstrate that it has registered with NERC as a precondition to being assigned a reliability project. As the Commission explained in Order No. 1000, all entities that are users, owners or operators of the electric bulk power system must register with NERC for performance of applicable reliability functions.[524] The procedures for registering as a Functional Entity are set by NERC and approved-by the Commission under section 215,[525] and it is not appropriate for the Commission to amend or interpret those procedures here under a section 206 action by requiring all public utility transmission providers to revise their tariffs to provide that a potential transmission developer must register with NERC if not otherwise required under the NERC procedures, merely to be eligible to propose a transmission project for selection in the regional transmission plan for purposes of cost allocation.

b. Evaluation of Proposals for Selection in the Regional Transmission Plan for Purposes of Cost Allocation

i. Final Rule

445. The Commission required each public utility transmission provider to amend its OATT to describe a transparent and not unduly discriminatory process for evaluating whether to select a proposed transmission facility in the regional transmission plan for purposes of cost allocation.[526] The Commission explained that this process must comply with the Order No. 890 transmission planning principles, ensuring transparency, and the opportunity for stakeholder coordination. The Commission further explained that the evaluation process must culminate in a determination that is sufficiently detailed for stakeholders to understand why a particular transmission project was selected or not selected in the regional transmission plan for purposes of cost allocation.[527] Finally, the Commission declined to require public utility transmission providers to revise their OATTs to provide a right to construct and own a transmission facility and also declined to allow a transmission developer to maintain for a defined period of time its right to build and own a transmission project that it proposed but that was not selected.[528]

ii. Requests for Rehearing and Clarification

446. Western Independent Transmission Group seeks rehearing of the Commission's rejection of its proposal to require the use of an independent third party observer to oversee evaluation and selection of competing transmission projects to ensure that the process is being managed fairly and efficiently.

447. Illinois Commerce Commission argues that it is necessary for the Commission to provide more specificity regarding the practical means by which transmission providers can facilitate competition between alternative proposals. It suggests that the transmission provider identify the planning needs to be met and then solicit developers to submit alternative plans to address those needs. Illinois Commerce Commission explains that this formalized process would provide a non-discriminatory and objective method for the transmission provider to

[521] *Id.* PP 323–24.

[522] *Id.* P 324.

[523] Importantly, Order No. 1000 did not provide transmission developers with a right to construct; rather, it required ''that a nonincumbent transmission developer must have the same eligibility as an incumbent transmission developer to use a regional cost allocation method or methods for any sponsored transmission facility selected in the regional transmission plan for purposes of cost allocation.'' *See id.* P 332.

[524] *Id.* P 342.

[525] NERC, Rules of Procedures (effective March 15, 2012), *available at http://www.nerc.com/files/NERC_ROP_Effective_20120315.pdf.*

[526] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 328.

[527] *Id.*

[528] *Id.* P 338.

evaluate alternative proposals, and argues that the Commission erred in not requiring such a process.

448. Similarly, FirstEnergy Service Company seeks clarification that regional transmission planning processes need only consider proposals that respond to identified needs, such that a ''needs first'' approach is acceptable. In support, FirstEnergy Service Company argues that a planning model that requires the regional planning process to analyze every individual proposal would render the process less manageable, timely, and effective. FirstEnergy Service Company also argues that, through Order No. 890, the Commission already has put in place the mechanisms necessary to encourage innovative transmission proposals.

449. LS Power requests that the Commission affirmatively clarify on rehearing that, if a region uses a sponsorship model for the assignment of projects, the regions must treat an application for a project by a nonincumbent transmission owner no differently from any other applicant, and that sponsors that meet nondiscriminatory sponsorship criteria are to be assigned construction and ownership of the projects they sponsor unless the regional planning entity adequately justifies assignment of the project to another entity, as PJM was required to do in the *Primary Power* case.[529] It states that without this explicit statement, some will attempt to assign projects to non-sponsor incumbent transmission owners on the basis of an inaccurate reading of paragraph 338, where the Commission declined to adopt any right to construct or ongoing sponsorship rights.

450. LS Power also requests that the Commission clarify that in a region using a sponsorship model rather than a competitive bidding model, the process established by each public utility transmission provider must include a specific mechanism to select, in a nondiscriminatory manner, among competing qualified sponsors of identical projects, or, as a backstop if no mechanism is agreed upon, to assign such projects equally among qualified entities that have sponsored identical projects. It explains that to the extent that only one of the sponsors has sponsored the same project in an immediately prior planning cycle, that the entity should have preference over those entities newly sponsoring the project. LS Power further suggests that the Commission should include a provision for ongoing sponsorship rights, with some recognition or benefit to an entity for continuing to advocate viable projects, at least between the continuing sponsor and new sponsors of the same project. Additionally, LS Power states that another mechanism to select among multiple sponsors of identical projects is to select the entity that is willing to guarantee the lowest net present value of its annual revenue requirement.

451. In addition, LS Power requests that the Commission clarify that to meet the ''not unduly discriminatory process'' requirement, the selection criteria must meet certain minimum standards. It states that the Commission should clarify that when cost estimates are part of selection criteria, costs must be scrutinized in an equal manner whether the project is sponsored by an incumbent or independent.

iii. Commission Determination

452. The Commission affirms the decision in Order No. 1000 to require each public utility transmission provider to amend its OATT to describe a transparent and not unduly discriminatory process for evaluating whether to select a proposed transmission facility in a regional transmission plan for purposes of cost allocation.[530] We also affirm the Commission's decision not to require public utility transmission providers to use an independent third party observer to oversee the evaluation and selection of competing transmission projects. In Order No. 1000, the Commission encouraged public utility transmission providers to consider ways to minimize disputes, such as through additional transparency mechanisms.[531] However, the Commission did not mandate any particular approach, and is not persuaded now that an independent third party observer is necessary or appropriate in all regions. Moreover, the Commission noted that the requirements of the dispute resolution principle of Order No. 890 apply to the regional transmission planning process.[532] Thus, if a dispute cannot be resolved by public utility transmission providers in the regional transmission planning process, entities may take advantage of that transmission planning region's dispute resolution provision. Additionally, as noted in Order No. 1000, public utility transmission providers in consultation with other stakeholders in a region may, if they choose, propose to use an independent third-party observer and we will review any such proposal on compliance.[533]

453. While Order No. 1000 permits the public utility transmission providers in a region to adopt a ''needs first'' approach to transmission planning such as that advocated by the Illinois Commerce Commission and FirstEnergy Service Company, the Commission declined to adopt a one-size-fits-all approach to transmission planning. The Commission believes that there are many different approaches to transmission planning and requires only that the transmission planning process adopted by a transmission planning region satisfy the transmission planning principles discussed in Order No. 1000 and this order. Thus, we decline to rule in the abstract in advance of the compliance filings whether any particular transmission planning process is the only appropriate process for all regions.

454. The Commission clarifies that the public utility transmission providers in a transmission planning region must use the same process to evaluate a new transmission facility proposed by a nonincumbent transmission developer as it does for a transmission facility proposed by an incumbent transmission developer. In Order No. 1000, the Commission required each public utility transmission provider to adopt a transparent and not unduly discriminatory evaluation process that complies with the Order No. 890 transmission planning principles.[534] However, this requirement does not preclude public utility transmission providers in regional transmission planning processes from taking into consideration the particular strengths of either an incumbent transmission provider or a nonincumbent transmission developer during its evaluation.[535]

455. The Commission denies LS Power's other requests for rehearing regarding the selection of a transmission developer. The Commission declined to address the selection of a transmission developer in Order No. 1000. Aside from requiring the public utility transmission providers in a region to establish criteria to assess a transmission developer's qualifications to have its proposed transmission project considered for selection in a

[529] LS Power at 6 (*Primary Power, LLC,* 131 FERC ¶ 61,015, at P 65 (2010)).

[530] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 328.

[531] *Id.* P 330.

[532] *Id.* P 330 n.306.

[533] Order No. 1000, FERC Stats. & Regs. ¶ 31,323.

[534] *Id.* P 328.

[535] *See id.* P 260 (''An incumbent public utility transmission provider is free to highlight its strengths to support transmission project(s) in the regional transmission plan, or in bids to undertake transmission projects in regions that choose to use solicitation processes.'').

regional transmission plan for purposes of cost allocation, Order No. 1000 also requires public utility transmission providers in a region to adopt transparent and not unduly discriminatory criteria for selecting a new transmission project in a regional transmission plan for purposes of cost allocation. We decline to set certain minimum standards for the criteria used to select a transmission facility in a regional transmission plan for purposes of cost allocation other than to require that these selection criteria be transparent and not unduly discriminatory. We also find that this purpose is met adequately by the transmission planning principles of Order No. 890. We also anticipate that selection criteria will vary from transmission planning region to transmission planning region in accordance with each transmission planning region's needs, just as other aspects of regional transmission planning processes will vary, and LS Power has not persuaded us that such flexibility is inappropriate. However, we clarify that when cost estimates are part of the selection criteria, the regional transmission planning process must scrutinize costs in the same manner whether the transmission project is sponsored by an incumbent or nonincumbent transmission developer.

456. If a transmission project is selected in a regional transmission plan for purposes of cost allocation, Order No. 1000 requires that the transmission developer of that transmission facility (whether incumbent or nonincumbent) must be able to rely on the relevant cost allocation method or methods within the region should it move forward with its transmission project.[536] We are not persuaded to change this approach on rehearing. Further, we reiterate that we do not require public utility transmission providers in a region to adopt a provision for ongoing sponsorship rights, for the reasons set out in Order No. 1000. The Commission concluded that granting transmission developers an ongoing right to build sponsored transmission projects could adversely impact the regional transmission planning process.[537] We are not persuaded to reverse our decisions on the selection of transmission developers. While we acknowledge LS Power's concerns, we do not believe they warrant any revision of the selection of transmission developers at this time given the diversity of methods for selecting transmission developers used around the nation.

c. Reevaluation of Regional Transmission Plans When There Is a Project Delay and Reliability Compliance Obligations of Transmission Developers

i. Final Rule

457. In Order No. 1000, the Commission required each public utility transmission provider to amend its OATT to describe the circumstances and procedures under which public utility transmission providers in the regional transmission planning process will reevaluate the regional transmission plan to determine if delays in the development of a transmission facility selected in a regional transmission plan for purposes of cost allocation require evaluation of alternative solutions, including those proposed by the incumbent transmission provider, to ensure the incumbent transmission provider can meet its reliability needs or service obligations.[538]

458. The Commission also explained that if a violation of a NERC reliability standard by an incumbent would result from a nonincumbent transmission developer's decision to abandon a transmission facility meant to address such a violation, the incumbent transmission provider does not have the obligation to construct the nonincumbent's project.[539] Rather, the incumbent transmission provider must identify the specific NERC reliability standard(s) that would be violated and submit a mitigation plan to address the violation.[540] The Commission explained that if the incumbent public utility transmission provider follows the NERC-approved mitigation plan, the Commission will not subject it to enforcement action for the specific NERC reliability standard violation(s) caused by a nonincumbent transmission developer's decision to abandon a transmission facility.[541]

459. The Commission also noted that, when a nonincumbent transmission developer becomes subject to the requirements of FPA section 215 and the regulations thereunder, it will be required to comply with all applicable reliability obligations, including registering with NERC for performance of applicable reliability functions.[542] The Commission stated that if there are concerns about when compliance with NERC registration and reliability standards would be triggered, the appropriate forum to raise these questions and request clarification is the NERC process.[543]

ii. Requests for Rehearing and Clarification

460. Some petitioners question whether the reevaluation requirement set forth in Order No. 1000 are sufficient to protect incumbent transmission providers from the repercussions related to a nonincumbent's failure to build a project in time.[544] For instance, these petitioners argue that the Commission failed to protect incumbent transmission providers from the increased risk of violations of state reliability or resource adequacy requirements, and other state service obligations.[545] MISO Transmission Owners Group 2 also adds that the incumbent utility could face civil liability, state regulatory sanctions, and financial harm resulting from damage to its own facilities or the facilities of another entity caused by the action of the nonincumbent.

461. Some commenters argue that incumbent developers should not be burdened with monitoring the status of a nonincumbent developer's progress. Specifically, if the reevaluation requirement would obligate incumbents to discover or address nonincumbent delays prior to being notified by the nonincumbent, Southern Companies request rehearing of this requirement in Order No. 1000.[546] Southern Companies also request rehearing of the reevaluation requirement to the extent it could inhibit, prevent or slow an incumbent's decision to address a delay or the implementation of its corrective plan. Similarly, Southern California Edison requests that the Commission require regional transmission planning entities to develop protocols for how such transmission planning entities will: (1) Be kept apprised by nonincumbent developers of the status of their projects; and (2) notify the applicable incumbent transmission owner that it needs to develop a mitigation plan because a project has been delayed or abandoned by a nonincumbent developer. In addition, Southern Companies contend that each incumbent transmission provider and planning authority should be permitted

[536] *Id.* P 339.

[537] *Id.*

[538] *Id.* P 329.

[539] *Id.* P 344.

[540] *Id.*

[541] *Id.*

[542] *Id.* P 342.

[543] *Id.* P 343.

[544] *See, e.g.,* Southern Companies; Edison Electric Institute; MISO Transmission Owners Group 2; and Xcel.

[545] *See, e.g.,* Edison Electric Institute; and MISO Transmission Owners Group 2.

[546] Southern Companies at 78 (citing *McElroy Electronics Corp.* v. *FCC,* 990 F.2d 1351, 1358 (D.C. Cir. 1993)).

to reevaluate its own local transmission plan to determine whether a nonincumbent's delay in constructing a regional facility will adversely impact reliability on the incumbent's system. In addition, Southern Companies argue that because the reevaluation requirement does not protect against the need to implement operational adjustments, Order No. 1000 fails to protect against service reliability problems and fails to weigh the adverse impacts against the benefits that the Commission foresees.

462. Ad Hoc Coalition of Southeastern Utilities and Large Public Power Council also assert that there is no substantial evidence for concluding, as the Commission does in paragraph 263 of Order No. 1000, that the potential costs associated with a delayed or abandoned nonincumbent transmission facility are remediable by a reevaluation of the regional plan. For example, Large Public Power Council explains that by the time construction delays place a system at risk, the damage will have been done, since such delays will postdate the planning that contemplated the facilities at issue, often by several years. As such, it maintains that even if the incumbent utility can step in with sufficient lead-time so that reliability is not threatened, and the cost of this activity is recoverable, there is little that can be done to save ratepayers from the associated costs, and there is no basis to conclude that nonincumbent participation in the transmission development process will therefore be worth it.

463. Several petitioners seek rehearing and clarification of the Commission's decision to allow incumbent transmission providers to implement a NERC mitigation plan to avoid an enforcement action if a nonincumbent transmission developer abandons a project needed to meet a reliability need. For example, Xcel asserts that Order No. 1000's discussion of a NERC mitigation plan may involve interrupting load under certain conditions, or implementing rolling outages. Xcel argues that this degradation of service to end use customers is contrary to the fundamental purposes of FPA section 215 and would also result in a loss of revenues to the utility.

464. Transmission Dependent Utility Systems argue that Order No. 1000 sheds no light on whether its mitigation plan solution is realistic or available and does not address who will be responsible for maintaining power if neither the incumbent nor the nonincumbent transmission provider can be held accountable for completion or maintenance of reliability-driven projects. Similarly, PSEG Companies argue that the problem of abandonment by a nonincumbent of a project needed for reliability cannot be fixed by reliability standards or by mitigation plans submitted in ''compliance'' with those standards. They state that the Commission failed to recognize that NERC reliability standards will not be applicable to a nonincumbent developer unless and until the project is constructed and in-service.

465. Petitioners point out possible difficulties that may arise because similar terms have distinct meanings in a public utility transmission provider's OATT under FPA 205 and the reliability standards under FPA 215. Several petitioners argue that it is not always a public utility transmission provider that is responsible for conducting a reevaluation or developing a mitigation plan.[547] For instance, Southern Companies argue that public utility transmission providers do not conduct transmission planning or evaluate or reevaluate transmission plans. Instead, Southern Companies argue that planning authorities and transmission planners are the appropriate entities to determine the impacts of a delay on local plans and are responsible for meeting reliability and service obligations, including the state-mandated duty to serve native load. Southern Companies argue that the Commission cannot remove or dilute that responsibility by delegating it to another entity without preempting state law. Southern Companies state that if Order No. 1000 does not intend the term ''public utility transmission provider'' to mean Transmission Service Provider under the NERC Functional Model, the Commission must grant rehearing to determine what category of Registered Entity is meant, or extend the commencement of the 12-month compliance window until NERC has determined which category of Registered Entity is appropriate to conduct the activities required by Order No. 1000.[548] Furthermore, Edison Electric Institute seeks clarification that an incumbent transmission provider need not have a retail distribution service territory and need not construct the new facilities entirely within its retail distribution service territory to qualify for protection from an enforcement action as described in paragraph 344 of Order No. 1000.

466. In addition, PSEG Companies argue that using the term ''transmission provider'' creates confusion because, under the NERC Functional Model, the term could apply to a number of different functions, and these different functions are very different even if in ISO/RTO regions the ''transmission provider'' is the ISO/RTO. PSEG Companies argue that the Commission erred by seeking to impose the responsibility to develop a ''mitigation plan'' onto incumbent transmission owners, and that this requirement demonstrates that the Commission misunderstands the NERC process. Thus, according to PSEG Companies, the process for addressing nonincumbents' abandonment of facilities would not work as envisioned, at least in the ISO/RTO context where the transmission owner is not responsible for planning the system and would not be responsible for filing a mitigation plan in the event of abandonment.

467. Other petitioners request clarification regarding the scope of the waiver. Edison Electric Institute recommends that the Commission use NERC terminology to clarify the scope of the waiver. Other petitioners argue that if the waiver applies only to the incumbent transmission provider as defined in Order No. 1000, the application is too narrow.[549] In addition to the incumbent transmission provider, Edison Electric Institute argues that the protection from an enforcement action should extend to other entities that might be found in violation of a reliability standard, such as balancing authorities and reliability coordinators. APPA agrees and adds that all of the transmission providers will be adversely affected to at least some extent due to the interconnected nature of the transmission network. Transmission Dependent Utility Systems add that third parties with NERC reliability obligations for certain transmission facilities, such as municipal utilities and rural electric cooperatives, also should be held harmless from penalties and NERC enforcement actions if a nonincumbent transmission developer abandons or fails to maintain a project needed to address reliability concerns. For example, even though Southern California Edison considers CAISO to be the transmission provider, Southern California Edison asserts that it develops and implements NERC mitigation plans as the NERC registered

[547] *See, e.g.,* PSEG Companies; and Southern Companies.

[548] We note that the capitalized terms refer to specific terms used in the NERC Reliability Standards.

[549] *See, e.g.,* Edison Electric Institute; Southern California Edison; and APPA.

transmission owner and therefore should be entitled to protection.

468. Southern Companies also request rehearing of Order No. 1000's failure to explain its departure from existing policy and regulations regarding mitigation plans. Southern Companies argue that requiring an incumbent to submit a mitigation plan for a nonincumbent's abandonment of necessary facilities would bestow upon the incumbent the impossible task of ensuring that another entity will not make poor business decisions, go bankrupt, or otherwise abandon or cancel its projects. Furthermore, Southern Companies state that Order No. 1000 indicates the incumbent may need to construct redundant and duplicate facilities to guard against the potential of nonincumbent delay or abandonment of its project. In addition, Southern Companies request rehearing to the extent incumbents are required to propose a corrective action for review by the regional process because such a requirement would impair service reliability.[550] Southern Companies also request clarification that the costs of the delayed regional facility will not be allocated to an incumbent that constructs a local transmission solution to meet its reliability or service needs in the face of delay.

469. Petitioners also argue that the protection from an enforcement action should be applicable to any project that an incumbent relies on to satisfy its reliability obligations, including reliability, public policy or economic-based projects.[551] Southern California Edison points out that a project intended to address a NERC violation or other reliability concerns may be dependent on another transmission project being completed first, including a public policy or economic project. Ameren argues that such other projects, which may have received regional cost allocation, will almost certainly have some measure of reliability effect because the grid is interconnected and that the failure of any such project could cause a blackout.

470. Some petitioners seek clarification that the protections found in paragraph 344 will prevent the Commission, NERC, or a Regional Entity from considering a violation that is covered by this protection, or a mitigation plan developed to address such a violation, as a prior violation when determining the penalty for a new violation.[552] Moreover, Edison Electric Institute seeks clarification that the protections described in paragraph 344 will apply to any Reliability Standard violation, including an operationally-focused violation, resulting from abandonment of a project by a nonincumbent transmission developer. Edison Electric Institute asserts that it is unfair to provide protection only for violations specifically envisioned at the time the project was conceived. Finally, Edison Electric Institute seeks clarification that the safe harbor provision will prevent the Commission, NERC, or a Regional Entity from considering a violation that is covered by this safe harbor protection or a mitigation plan developed to address such a violation as a prior violation when determining the penalty for a new violation.

471. Southern California Edison requests that the Commission clarify that an incumbent transmission owner will not be subject to an enforcement action or any other sanction or penalty if it cannot follow or implement an approved mitigation plan for reasons beyond its control. It states that after Order No. 1000, a transmission owner may be asked to develop a mitigation plan without much of the key information, which means an incumbent transmission owner may not be able to develop an infallible mitigation plan and should not be penalized if implementation of its plan is delayed or if the plan needs to be revised to reflect new information that becomes known to the incumbent when the mitigation efforts are underway.

472. In addition, Southern California Edison requests that the Commission clarify that penalties, sanctions, or enforcement actions also will not be levied against an incumbent transmission owner for reliability problems that arise from the actions of a nonincumbent transmission developer in connection with delays of a transmission facility, or the operation or maintenance thereof.

473. Southern California Edison also argues that the Commission should clarify that, as long as the incumbent transmission owner submits its mitigation plan to an appropriate regional entity, the transmission owner should not face any enforcement actions, penalties or sanctions while the mitigation plan is pending approval. Southern California Edison states that it does not submit mitigation plans directly to NERC, but instead initially submits its plan for approval to the Regional Entity. Therefore, Southern California Edison states that there will be some inevitable delay between the time that a transmission owner submits a mitigation plan and the time that the plan is approved by NERC, and argues that it should not be penalized for such inevitable delay.

474. Some petitioners argue that the Commission's reevaluation and enforcement provisions in Order No. 1000 are inconsistent with section 215 of the FPA, and fail to adequately protect incumbents.[553] For example, Edison Electric Institute asserts that if an incumbent transmission provider violates state resource adequacy or reliability requirements, it may be subject to significant monetary penalties and other sanctions, which the Commission's grant of protection from a section 215 enforcement action has no effect on and cannot preempt. Edison Electric Institute argues that the Commission failed to discuss these implications and has thus engaged in arbitrary and capricious decision-making and should grant rehearing to remove the right of first refusal for reliability projects.

475. Xcel argues that Order No. 1000 ignores the substantial record evidence that the policies adopted are inconsistent with the objectives of section 215 of the FPA and the Commission's initiatives to improve electric system reliability through mandatory standards. Xcel contends that forcing utility transmission providers to rely on a third party to fulfill section 215 obligations does not constitute reasoned decision-making. Southern Companies add that Order No. 1000's nonincumbent requirements pose threats to reliability and economic service by forcing disintegration of the transmission network. MISO Transmission Owners Group 2 argues that nothing in EPAct 2005 authorizes the Commission to provide blanket waivers of critical reliability standards for the purposes of achieving some policy preference unrelated to the enforcement of mandatory reliability standards.

476. Southern Companies also argue that the Commission impermissibly uses section 206 to impose reliability requirements instead of using its section 215 authority. Southern Companies argue that this action violates the Whole Act Rule by making section 215's goal of protecting reliability subservient to section 206.[554] Accordingly, Southern

[550] Southern Companies at 81–82 (citing *Motor Vehicle Mfrs. Assoc. of the United States, Inc.* v. *State Farm Mutual Auto. Ins. Co.,* 463 U.S. 29, 43 (1983)).

[551] *See, e.g.,* Southern California Edison; Xcel; Ameren; and Edison Electric Institute.

[552] *See, e.g.,* Edison Electric Institute; and Southern California Edison.

[553] *See, e.g.,* Xcel; Southern Companies; and MISO Transmission Owners Group 2.

[554] Southern Companies at 77 n.251 (citing 5 U.S.C. 706).

Companies assert that the Commission should have gone through the Commission-approved NERC standards and enforcement processes established pursuant to section 215 of the FPA, the Commission's regulations, and Commission precedent, rather than unilaterally developing these reliability-related reevaluation and enforcement protections and imposing their requirements onto users, owners, and operators of the bulk-power system. Southern Companies argue the enforcement action waiver is inconsistent with, and may conflict with existing NERC Reliability Standards.

iii. Commission Determination

477. The Commission affirms its decision to require each public utility transmission provider to amend its OATT to describe the circumstances and procedures under which public utility transmission providers in the regional transmission planning process will reevaluate the regional transmission plan to determine if delays in the development of a transmission facility selected in a regional transmission plan for purposes of cost allocation require evaluation of alternative solutions, including those proposed by the incumbent transmission provider, to ensure the incumbent transmission provider can meet its reliability needs or service obligations.[555] As the Commission explained in Order No. 1000, the focus here is on ensuring that adequate processes are in place to determine whether delays associated with completion of a transmission facility selected in a regional transmission plan for purposes of cost allocation have the potential to adversely affect an incumbent transmission provider's ability to fulfill its reliability needs or service obligations. We believe that if these processes are followed, incumbent transmission providers should be able to meet reliability related requirements.

478. In response to Xcel's and Southern Companies' argument that the reevaluation requirement does not protect against the need to implement operational adjustments, the present operationally-focused NERC reliability standards require Functional Entities to operate so that the portion of the system that is in service at that time will be capable of delivering the output of generation to firm demand and transfers within the applicable performance criteria. Accordingly, a Functional Entity must prepare its system to operate regardless of whether a transmission project is delayed or abandoned. Thus, the Commission concludes that there is no need to set requirements in addition to those already established in the applicable NERC reliability standards.

479. In response to those petitioners concerned that they must individually monitor the status of a nonincumbent transmission developer's progress in developing its transmission facility selected in the regional transmission plan for purposes of cost allocation, we note that transmission planners and transmission developers already routinely communicate regarding the status of the construction of a transmission project. Consistent with applicable NERC Reliability Standards, a Functional Entity remains responsible for complying with all applicable Reliability Standards, such as studying performance of its system and deciding when it must develop corrective plans to ensure that its system responds reliably as prescribed by those standards.[556] As such, we emphasize that Order No. 1000 does not change any obligations an incumbent transmission provider, as a Functional Entity, may have under the NERC Reliability Standards to monitor a nonincumbent transmission developer's progress in developing its transmission facility selected in the regional transmission plan for purposes of cost allocation. Furthermore, Order No. 1000 left it to public utility transmission providers in a transmission planning region to adopt procedures in their OATTs for reevaluating transmission facilities selected in the regional transmission plan for purposes of cost allocation. We continue to believe this approach is appropriate.

480. The Commission also affirms, with certain clarifications, its decision in Order No. 1000 to not subject an incumbent public utility transmission provider to a penalty for a violation of a NERC reliability standard caused by a nonincumbent transmission developer's decision to abandon a transmission facility if the incumbent public utility transmission provider has identified the violation and submitted a NERC mitigation plan to address it.[557] The Commission used ''enforcement action'' in Order No. 1000, but is not using this term here because ''enforcement action'' also could imply that Registered Entities are not going to be required to mitigate any NERC reliability standards violations. The Commission clarifies that, although it will not seek penalties, it will ensure that Registered Entities implement appropriate mitigation plans.

481. The Commission agrees with petitioners that argue that entities other than incumbent public utility transmission providers may violate a NERC reliability standard in the event that a nonincumbent transmission developer abandons a transmission facility. In some regions, the incumbent public utility transmission provider may not be the entity responsible for complying with the NERC reliability standards implicated by the abandonment of a nonincumbent transmission developer's project. We also agree with Ameren and other petitioners that argue that the abandonment of a nonincumbent transmission project that is designed to meet economic needs or transmission needs driven by a Public Policy Requirement could impact reliability. Therefore, we clarify that the Commission will not subject a Registered Entity[558] to a penalty for a violation of a NERC reliability standard caused by a nonincumbent transmission developer's decision to abandon any type of transmission facility selected in the regional transmission plan for purposes of cost allocation if, on a timely basis, that Registered Entity identifies the violation and complies with all of its obligations under the NERC reliability standards to address it.

482. The remaining requests for rehearing or clarification posit enforcement situations that are uncertain or speculative. We decline to rule on these requests for rehearing or clarification because we find that they are premature. We believe that, with the clarifications granted above, entities have sufficient information to understand when the Commission will not subject a Registered Entity to enforcement action for a violation of a NERC reliability standard caused by a nonincumbent transmission developer's decision to abandon a transmission facility. Furthermore, many of these petitions in effect argue that the Commission should not have required

[555] Order 1000, FERC Stats. & Regs. ¶ 31,323 at P 329.

[556] NERC Reliability Standards in the Facility Connection and Transmission Planning series ensure evaluation of the reliability impact of the new facilities connections, and coordination and results sharing by the entities involved, as well as development of corrective plans if reliability requirements are not met when projects are delayed or abandon.

[557] Order 1000, FERC Stats. & Regs. ¶ 31,323 at P 344.

[558] We use the term Registered Entity to refer an owner, operator, or user of the Bulk Power System, or the entity registered as its designee for the purpose of compliance, that is included in the NERC Compliance Registry. *See,* North American Electric Reliability Corporation, Compliance Monitoring and Enforcement Program, Appendix 4C to the Rules of Procedures (effective Jan. 31, 2012), *available at: http://www.nerc.com/files/Appendix_4C_CMEP_20120131.pdf.*

public utility transmission providers to eliminate a federal right of first refusal from Commission jurisdictional-tariffs and agreements in Order No. 1000. The Commission has adequately explained in Order No. 1000 and in this order the need for eliminating a federal right of first refusal.

483. Finally, contrary to arguments by petitioners, the Commission was not required to use its section 215 authority to adopt the reevaluation requirements or to state the circumstances under which it would exercise its enforcement discretion. Rather, the reevaluation requirement is a tariff obligation not a reliability obligation under section 215. Furthermore, in stating the circumstances under which the Commission would exercise its enforcement discretion, the Commission did not create new, or modify existing, NERC reliability standards. Had the Commission done so, it would be required to adopt a reliability standard through its authority set out in section 215. Instead, the Commission appropriately exercised its discretion under section 215 enforcement authority to set forth a particular circumstance when it will not e penalize a Registered Entity.

d. Recovery of Abandoned Plant Costs and Backstop Authority

i. Final Rule

484. In Order No. 1000, the Commission found that when an incumbent transmission provider is called upon to complete a transmission project that it did not sponsor, there would be a basis for the incumbent transmission provider to be granted abandoned plant recovery for that transmission facility, upon the filing of a petition for declaratory order requesting such rate treatment or a request under section 205 of the FPA.[559]

ii. Requests for Rehearing

485. APPA and Transmission Access Policy Study Group question the Commission's decision to grant abandoned plant cost recovery to an incumbent transmission provider in certain circumstances. Transmission Access Policy Study Group and APPA argue that granting incumbent transmission providers abandoned cost recovery under Order No. 1000 is an unjustified deviation from Order No. 679's case-by-case approach. Transmission Access Policy Study Group raises several questions that it asserts highlight the need for the Commission to look at the facts of each request for abandoned plant recovery rather than committing the public in all circumstances to pay for unfinished projects. APPA argues that abandoned plant cost recovery is an incentive that should be granted on a case-by-case basis where the granting of such an incentive is shown to be necessary and appropriate.

486. Southern California Edison also notes that Order No. 1000 states in paragraph 344 that the incumbent transmission owner does not have an obligation to construct a transmission facility intended to address a possible NERC violation, but then states in paragraph 267 that there may be circumstances when an incumbent may be called upon to complete a project that it did not sponsor. Southern California Edison requests that the Commission clarify: (1) How the statements in paragraphs 267 and 344 should be reconciled so that they are consistently interpreted and implemented; (2) in which situations a transmission provider may be required to complete a transmission facility it did not sponsor; and (3) what that completion obligation entails.

487. Southern California Edison also seeks clarification that Order No. 1000 does not preclude regions from applying backstop transmission development obligations to all participating transmission owners in the region and allows regions that impose backstop obligations to apply them on an equivalent basis among incumbents and nonincumbents. Southern California Edison argues that to require only incumbents to serve as the safety-net for all nonincumbent projects would impose a burden upon incumbents that could impede their ability to compete for projects. On the other hand, Xcel recommends that tariffs incorporate a backstop that reflects the incumbent utility's obligation as provider of last resort to build transmission needed for reliability even if the incumbent does not exercise a right of first refusal and no one else offers to build it.

488. Southern California Edison requests clarification that the incumbent transmission owner will be fully compensated for mitigation costs through ''grid-wide'' rates to offset the substantial burden of developing and implementing mitigation plans. In addition, Edison Electric Institute seeks clarification that an incumbent transmission provider that steps in to complete an abandoned reliability project in the circumstances discussed in paragraph 344 of Order No. 1000, it has no obligation to purchase the facilities, materials, or any other assets related to the abandoned project, at cost or otherwise. It argues that such a requirement would provide unwarranted financial protections for nonincumbent transmission developers, and remove one of the key incentives to complete a project once begun. Similarly, Southern Companies argue that Order No. 1000 will discriminate in favor of third party developers at the expense of an incumbent's native load and OATT customers unless the Commission ensures that developers of regional projects are held responsible and accountable for any and all adverse effects of their construction delays or abandonments upon incumbents, including any increased costs caused thereby.[560]

iii. Commission Determination

489. In response to Transmission Access Policy Study Group and APPA, we clarify that we will, consistent with Order No. 679,[561] grant abandoned plant recovery on a case-by-case basis. Order No. 1000 did not provide a blanket grant of abandoned plant recovery, but merely stated that where an incumbent transmission provider is called upon to complete a transmission project that another entity has abandoned, this would be a basis for the incumbent transmission provider to be granted abandoned plant recovery for that transmission facility, upon the filing of a petition for declaratory order requesting such rate treatment or a request under section 205 of the FPA.[562]

490. In response to Southern California Edison, nothing in Order No. 1000 requires an incumbent transmission provider to construct a nonincumbent transmission developer's transmission project selected in the regional transmission plan for purposes of cost allocation if it abandons a transmission facility.[563] We note, however, that some RTOs and ISOs may have the authority under their tariff or membership agreements to direct a member to build a transmission facility under certain circumstances.[564] Further, Order No. 1000 did not address the issue of backstop construction authority or responsibility for any transmission project, whether undertaken initially by an incumbent or a nonincumbent transmission developer. Accordingly,

[559] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 267.

[560] Southern Companies at 83–84 (citing *Chicago* v. *FPC,* 385 F.2d 629, 637 (D.C. Cir. 1967)).

[561] Order No. 679, FERC Stats. & Regs. ¶ 31,222.

[562] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 267.

[563] *Id.* P 344.

[564] *See, e.g.,* PJM Consolidated Transmission Owners Agreement at section 4.2.1.We note that a nonincumbent transmission developer that becomes a member of an RTO or ISO may be subject to an obligation to build that applies to transmission-owning members.

this issue is beyond the scope of this proceeding, and we will not address it on rehearing.

491. In response to Southern California Edison's request that incumbent transmission providers be compensated for the cost of developing implementing a mitigation plan through ''grid-wide'' rates, we did not provide a generic answer in Order No. 1000 and do not do so here. That is, we are not deciding here whether a transmission provider may recover, or how it may recover, the costs that result from complying with the Reliability Standards if a nonincumbent transmission developer delays or abandons a needed transmission project.

492. In response to Edison Electric Institute, the Commission does not require under Order No. 1000 that an incumbent transmission developer purchase the facilities, materials, or any other assets related to an abandoned project that the incumbent transmission provider determines it must complete. However, Order No. 1000 also does not preclude an incumbent transmission developer from purchasing such facilities, materials or other assets if it believes it is prudent to do so.

C. Interregional Transmission Coordination

1. Interregional Transmission Coordination Requirements

a. Interregional Transmission Coordination Procedures and Geographical Scope

i. Final Rule

493. In Order No. 1000, the Commission required each public utility transmission provider, through its regional transmission planning process, to establish further procedures with each of its neighboring transmission planning regions for the purpose of (1) coordinating and sharing the results of respective regional transmission plans to identify possible interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities; and (2) jointly evaluating such facilities, as well as jointly evaluating those transmission facilities that are proposed to be located in more than one transmission planning region.[565] Furthermore, the Commission required each public utility transmission provider, through its regional transmission planning process, to describe the methods by which it will identify and evaluate interregional transmission facilities and to include a description of the type of transmission studies that will be conducted to evaluate conditions on neighboring systems for the purpose of determining whether interregional transmission facilities are more efficient or cost-effective than regional facilities.[566]

494. In Order No. 1000, the Commission also required each public utility transmission provider through its regional transmission planning process to coordinate with the public utility transmission providers in each of its neighboring transmission planning regions within its interconnection to implement the interregional transmission coordination requirements.[567] The Commission defined an interregional transmission facility as one that is located in two or more transmission planning regions.[568] The Commission declined to require, but did not prohibit, joint evaluation of other facilities or study of the effects in a second region of a new transmission facility proposed to be located in a single transmission planning region.[569] The Commission explained that to do otherwise could have the effect of mandating interconnectionwide transmission planning, because a transmission facility located within one transmission planning region can have effects on many systems in the interconnection, which could trigger a chain of multiregional evaluation processes. Furthermore, the Commission observed that its interregional transmission coordination requirements will assist transmission planners in understanding and managing the effects of a transmission facility located in one region on a neighboring region.[570]

ii. Requests for Rehearing and Clarification

495. AEP asks the Commission to ensure that the interregional coordination requirements apply to transmission needs driven by public policy requirements. Otherwise, AEP states, planners will settle on less efficient and less cost-effective solutions, which increase costs. AEP argues that it is arbitrary and capricious for the Commission not to require consideration of needs driven by public policy requirements as part of interregional coordination, in light of its findings on the importance of public policy considerations in the Final Rule. AEP also argues that requiring consideration of transmission needs driven by public policy requirements within a region but not between regions places too much emphasis and importance on the decisions about configuration of the planning regions given that the Commission has declined to prescribe the geographic scope of any transmission planning region.

496. Bonneville Power states that certain aspects of Order No. 1000 indicate that formal procedures need to cover only identification and joint evaluation rather than planning and developing interregional transmission facilities. If this is what the Commission meant, then Bonneville Power requests that the Commission so clarify.

497. On rehearing, MISO Transmission Owners Group 1 and Wisconsin PSC request that the Commission expand the definition of an interregional transmission facility. Specifically, MISO Transmission Owners Group 1 requests that the Commission find that transmission facilities physically located within one region can be considered interregional transmission facilities when they provide sufficient benefits as determined in accordance with the applicable interregional agreement or OATTs, and can be eligible for interregional cost allocation pursuant to criteria set forth in that agreement or those OATTs. Wisconsin PSC makes a similar argument. Wisconsin PSC also requests that the Commission remove the single-region limitation, and instead limit evaluation of a single-region project to interregional transmission planning processes that involve no more than two transmission planning regions. Wisconsin PSC adds that the Commission could further limit consideration by requiring the project sponsor to publicly identify a single-region transmission facility as benefiting the other affected region to ensure that a project does not ''fly under the radar.'' [571] Both Wisconsin PSC and MISO Transmission Owners Group 1 argue that their respective definitions eliminate the Commission's concern

[565] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 396.

[566] *Id.* P 398.

[567] *Id.* P 415.

[568] *Id.* P 482 n.374.

[569] Nevertheless, consistent with Cost Allocation Principle 4, each regional transmission planning process must identify the consequences of a proposed new transmission facility for other transmission planning regions. The Commission also stated that Order No. 1000 did not affect any obligations that public utility transmission providers may otherwise have to assess the effects of new transmission facilities on other systems, including, but not limited to, any other requirement of the OATT for interconnection studies, any requirement under the NERC reliability standards, and the requirements of Good Utility Practice. Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 416 n.351.

[570] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 416.

[571] Wisconsin PSC at 6–7.

that expanding the scope of interregional transmission coordination would lead to interconnectionwide transmission planning.

498. Furthermore, MISO Transmission Owners Group 1 argues that the Commission should expand the definition because the expanded definition would help ensure that the costs of such facilities are allocated in a manner that is at least roughly commensurate with the benefits received. Wisconsin PSC asserts that requiring regions to jointly consider single-region projects in the interregional planning process would diminish the risk of inadvertent free ridership, ensure that intended beneficiaries of a project are allocated a share of the project costs, and expand the set of potential cost-effective transmission solutions to regional transmission needs. Wisconsin PSC adds that not eliminating this exclusion may create a specific violation of the application of the cost causation/beneficiaries pay principles articulated in *Illinois Commerce Comm'n* v. *FERC,* which require beneficiaries of a transmission project to pay a roughly commensurate share of project costs.[572]

499. Wisconsin PSC and MISO Transmission Owners Group 1 also argue that it is especially important to expand the definition because MISO has extensive seams with neighboring RTOs and other regions. Wisconsin PSC adds that it is virtually impossible for MISO to plan a transmission line in those areas without providing potential benefits to PJM load. Thus, it argues that the single-region limitation would increase the free ridership that the Commission seeks to deter.

iii. Commission Determination

500. We deny AEP's arguments that Order No. 1000's interregional transmission coordination requirements do not adequately provide for consideration of transmission needs driven by Public Policy Requirements. In Order No. 1000, the Commission determined that interregional transmission coordination neither requires nor precludes longer-term interregional transmission planning, including the consideration of transmission needs driven by Public Policy Requirements.[573] Order No. 1000 stated that whether and how to address this issue with regard to interregional transmission facilities is a matter for public utility transmission providers, through their regional transmission planning processes, to resolve in the development of compliance proposals.[574] We clarify that Order No. 1000 does not require or prohibit consideration of transmission needs driven by Public Policy Requirements as part of interregional transmission coordination. However, such considerations are required through the regional transmission planning process, which is an integral part of interregional transmission coordination because all interregional transmission projects must be selected in both of the relevant regional transmission planning processes in order to receive interregional cost allocation. Therefore, consideration of transmission needs driven by Public Policy Requirements is an essential part of the evaluation of an interregional transmission project, not as part of interregional transmission coordination, but rather as part of the relevant regional transmission planning processes. As such, we continue to believe that the decision of whether and how to address these issues with regard to interregional transmission facilities in the regional transmission planning processes is a matter for public utility transmission providers to work out with their stakeholders in the development of compliance proposals.[575]

501. We clarify for Bonneville Power that Order No. 1000 only requires the development of a formal procedure to identify and jointly evaluate interregional transmission facilities that are proposed to be located in neighboring transmission planning regions.[576] We emphasize, however, that while the Commission does not require any particular type of studies to be conducted, the purpose of identifying and jointly evaluating interregional transmission facilities is to determine whether they may more efficiently or cost-effectively meet transmission needs than regional transmission facilities.[577]

502. We decline to expand the definition of an interregional transmission facility adopted in Order No. 1000, as requested by MISO Transmission Owners Group 1 and Wisconsin PSC. As the Commission explained in Order No. 1000, requiring joint evaluation of the effects of a new transmission facility proposed to be located solely in a single transmission planning region could, in effect, mandate interconnectionwide transmission planning. This is because transmission facilities located in one transmission planning region often have effects on multiple neighboring systems, which could trigger a chain of multilateral evaluation processes.[578] While the definitions of an interregional transmission facility proposed by MISO Transmission Owners Group 1 and Wisconsin PSC could help to restrict the range of proposed new transmission facilities subject to joint evaluation, we disagree that they are sufficient to address the Commission's concern that expanding the definition of an interregional transmission facility adopted in Order No. 1000 could mandate interconnectionwide transmission planning. Adopting MISO Transmission Owners Group 1 and Wisconsin PSC's expanded definitions of an interregional transmission facility could still, in effect, mandate that certain transmission projects located solely in a single transmission planning region be planned on a multilateral, if not interconnectionwide, basis, and we are not persuaded that such a requirement is necessary at this time. The Commission exercised its discretion in this rulemaking to improve regional transmission planning and bilateral interregional transmission coordination in a manner that does not have the effect of requiring interconnectionwide planning. Moreover, we reiterate here the Commission's conclusion in Order No. 1000 that imposing multilateral or interconnectionwide transmission coordination requirements at this time could frustrate the progress being made in the ARRA-funded transmission planning initiatives.[579]

503. We also do not believe it is necessary to expand the definition of an interregional transmission facility, as argued by Midwest ISO Transmission Owners Group 1 and Wisconsin PSC, in order to ensure that the costs of a transmission facility located in a single transmission planning region that benefits a neighboring transmission planning region are allocated commensurately with the benefits it provides. As we explain more fully below,[580] these arguments fail to take into account the relationship between the Commission's cost allocation reforms and the other reforms contained in Order No. 1000 and the need to balance a number of factors to ensure that the reforms achieve the goal of improved transmission planning. In particular, as we stated in Order No. 1000, these reforms establish a closer link between regional transmission planning and cost allocation, both of

[572] Wisconsin PSC at 5 (citing 576 F.3d 470 (7th Cir. 2009)).

[573] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 401.

[574] *Id.* P 401.

[575] *Id.*

[576] *Id.* P 435.

[577] *Id.* P 398.

[578] *Id.* P 416.

[579] *Id.* P 417.

[580] *See* discussion *infra* at section 0.

which involve the identification of beneficiaries. In light of that closer link, we continue to find that allowing one region to allocate costs unilaterally to entities in another region would effectively impose an affirmative burden on stakeholders to actively monitor transmission planning processes in numerous other regions in which they could be identified as beneficiaries and thus be subject to cost allocation. This would essentially result in interconnectionwide transmission planning with corresponding cost allocation, albeit conducted in a highly inefficient manner.[581]

504. We note, however, that the public utility transmission providers in neighboring transmission planning regions may negotiate an agreement to share the costs of a particular transmission facility with the beneficiaries in another transmission planning region, as they always have been free to do.[582] Further, nothing in Order No. 1000 precludes public utility transmission providers in consultation with stakeholders from voluntarily developing and proposing interregional transmission coordination procedures providing for the joint evaluation by more than one transmission planning region of a transmission facility located solely in one transmission planning region should the public utility transmission providers in neighboring transmission planning regions agree to do so.[583] Also, we reiterate that Order No. 1000's limited requirements for bilateral interregional transmission coordination do not prohibit either voluntary multilateral interregional transmission coordination or planning, or the development of stronger bilateral coordination agreements than the rule requires.

505. Finally, Wisconsin PSC specifically mentions that transmission lines in MISO often provide potential benefits to PJM load. As the Commission recognized in Order No. 1000, MISO and PJM developed a cross-border cost allocation method in response to Commission directives related to their intertwined configuration that permits them, in certain cases, to allocate to one RTO or ISO the cost of a transmission facility that is located entirely within the other RTO or ISO. We reiterate here that Order No. 1000 does not require MISO and PJM to revise their existing cross-border cost allocation method in response to Cost Allocation Principle 4.[584]

2. Implementation of the Interregional Transmission Coordination Requirements

a. Procedure for Joint Evaluation

i. Final Rule

506. The Commission required the developer of an interregional transmission project to first propose its transmission project in the regional transmission planning processes of each of the neighboring regions in which the transmission facility is proposed to be located. The submission of an interregional transmission project in each regional transmission planning process will trigger the procedure under which the public utility transmission providers, acting through their regional transmission planning processes, will jointly evaluate the proposed transmission project.[585] The Commission required that joint evaluation be conducted in the same general timeframe as, rather than subsequent to, each transmission planning region's individual consideration of the proposed transmission project.[586] For an interregional transmission facility to receive cost allocation under the interregional cost allocation method or methods developed pursuant to Order No. 1000, the Commission required that the transmission facility be selected in both of the relevant regional transmission plans for purposes of cost allocation.[587] Finally, the Commission directed each public utility transmission provider, through its transmission planning region, to develop procedures by which differences in planning criteria can be identified and resolved for purposes of jointly evaluating a proposed interregional transmission facility.[588]

ii. Requests for Rehearing and Clarification

507. Joint Petitioners and ITC Companies seek rehearing of the Commission's requirement that both neighboring transmission planning regions must agree to include a proposed interregional transmission facility in their respective regional transmission plans for it to be eligible for interregional cost allocation. Instead, Joint Petitioners argue that the Commission should require the preparation and approval of an interregional plan, or at the very least, provide a mechanism by which a sponsor of an interregional transmission project can obtain Commission review of a disagreement or failure to act by and among affected planning regions. They assert that requiring each region to include an interregional facility in its respective plan is counterproductive because the Commission did not require the consistent use of specific planning horizons or the performance of particular scenario analyses for purposes of regional planning. Additionally, Joint Petitioners contend that even if a project is determined to be the most efficient, cost-effective project for the broader region composed of both planning regions, either region may veto the project because those broader benefits are not considered in the individual regional plans.

508. WIRES states that the planning experiences of RTOs and ISOs and the record in this proceeding contain many examples of planning procedures and criteria that are suitable for two regions to coordinate their planning efforts. WIRES adds that adopting these procedures, which establish fixed timelines for decision, data exchange requirements, planning assumptions, and standard modeling techniques, along with clear opportunities for exceptions where necessary, would shorten and rationalize planning processes without dictating outcomes. WIRES asserts that technical conferences could be useful for developing a consensus on these matters.

iii. Commission Determination

509. We deny Joint Petitioners' and ITC Companies' request for rehearing of Order No. 1000's requirement that an interregional transmission facility must be selected in each relevant regional transmission plan for purposes of cost allocation to be eligible for cost allocation under the interregional cost allocation method or methods.[589] Rather, we reaffirm this requirement. As stated above, Order No. 1000 establishes a closer link between transmission planning and cost allocation. As discussed more fully below in the section on stakeholder participation,[590] Order No. 1000 provides for stakeholder involvement in the consideration of an interregional transmission facility primarily through the regional transmission planning processes.[591] We

[581] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 660.

[582] *Id.* P 658.

[583] *Id.* P 416.

[584] *Id.* P 662.

[585] *Id.* P 436.

[586] *Id.* P 439.

[587] *Id.* P 436.

[588] *Id.* P 437.

[589] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 436.

[590] *See* discussion *infra* at section 0.

[591] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 465; *see also id.* P 443.

therefore conclude that this requirement is necessary to ensure that stakeholders have an opportunity to provide meaningful input with respect to proposed interregional transmission facilities before such facilities are selected in each relevant regional transmission plan for purposes of cost allocation.

510. We disagree with Joint Petitioners' contention that Order No. 1000 did not require consistency in planning horizons or scenario analyses. In Order No. 1000, the Commission directed each public utility transmission provider, through its transmission planning region, to develop procedures by which differences in the data, models, assumptions, planning horizons, and criteria used to study a proposed interregional transmission project can be identified and resolved for purposes of jointly evaluating an interregional transmission project.[592] This approach allows regions the flexibility to develop procedures that work for them, while still addressing the concern that joint evaluation of a proposed interregional transmission facility cannot be effective without some effort by neighboring transmission planning regions to harmonize differences in the data, models, assumptions, planning horizons, and criteria used to study a proposed transmission project.[593] We therefore decline to adopt WIRES' suggestion that we require that public utility transmission providers implement certain specific planning procedures or criteria, or that we hold a technical conference to consider such matters.

511. Moreover, we decline to require the preparation and approval of an interregional transmission plan or to adopt a mechanism for the Commission to review neighboring transmission planning regions' disagreements about or failure to act on a proposed interregional transmission facility as requested by Joint Petitioners. Joint Petitioners have not convinced us that such measures are necessary in this generic rulemaking. As the Commission found in Order No. 1000, the interregional transmission coordination reforms do not require the creation of a distinct interregional transmission planning process to produce an interregional transmission plan or the formation of interregional transmission planning entities. Rather, the requirement is for public utility transmission providers to consider whether the local and regional transmission planning processes result in transmission plans that meet local and regional transmission needs more efficiently and cost-effectively, after considering opportunities for collaborating with public utility transmission providers in neighboring transmission planning regions.[594] However, as the Commission stated in Order No. 1000, public utility transmission providers may voluntarily engage in interregional transmission planning and, as relevant, rely on such a planning process to comply with the interregional transmission coordination requirements of Order No. 1000.[595]

512. Finally, we understand Joint Petitioners' concern that a transmission planning region may decline to select an interregional transmission project in its regional transmission plan for purposes of cost allocation if the project does not sufficiently benefit that region, even if it is the more efficient or cost-effective project for the broader multiregional area. This is another version of the argument made by petitioners that prefer interconnectionwide transmission planning to regional transmission planning. However, we decline to require interconnectionwide planning in this rulemaking for the reasons set out in Order No. 1000 and summarized above. We understand that, under the interregional transmission coordination procedures of Order No. 1000, an interregional transmission facility is unlikely to be selected for interregional cost allocation unless each transmission planning region benefits or the transmission planning region that benefits compensates the region that does not through a separate agreement—and that this feature would not necessarily apply for interconnectionwide planning. We continue to believe however that, under the regional transmission planning approach adopted in Order No. 1000, it is appropriate for each transmission planning region to determine for itself whether to select in its regional transmission plan for purposes of cost allocation an interregional transmission facility that extends partly within its regional footprint based on the information gained during the joint evaluation of an interregional transmission project.

b. Stakeholder Participation

i. Final Rule

513. In Order No. 1000, the Commission did not require the interregional transmission coordination procedures to meet the requirements of the transmission planning principles required for local planning (under Order No. 890) and regional planning (under Order No. 1000).[596] The Commission explained that stakeholders will have the opportunity to participate fully in the consideration of interregional transmission facilities during the regional transmission planning process, because each region must select such a facility in its regional transmission plan for purposes of cost allocation in order for it to be eligible for interregional cost allocation.[597] The Commission also required public utility transmission providers to make transparent the analyses undertaken and determinations reached by neighboring transmission planning regions in the identification and evaluation of interregional transmission facilities.[598] Last, the Commission required that each public utility transmission provider give stakeholders the opportunity to provide input into the development of its interregional transmission coordination procedures and the commonly agreed-to language to be included in its OATT.[599]

ii. Requests for Rehearing and Clarification

514. Transmission Dependent Utility Systems and PSEG Companies argue that the Commission should have required public utility transmission providers to provide for more stakeholder participation in the interregional coordination process and procedures. Transmission Dependent Utility Systems also seek clarification or, in the alternative, argue that the Commission should require on rehearing, that stakeholders have a meaningful opportunity to participate in the development of the interregional coordination process before it is submitted to the Commission in a compliance filing, whether the process is reflected in the OATT or in a bilateral agreement.

515. In addition, Transmission Dependent Utility Systems argue that stakeholders must be allowed to participate throughout the process to ensure that load-serving transmission customers receive treatment comparable to the treatment transmission providers accord their retail and wholesale merchant functions, as required by sections 205 and 217(b)(4), Order No. 890, and the judicial requirement for reasoned decision-making.[600] PSEG

[592] *Id.* P 437.

[593] *Id.*

[594] *Id.* P 399.

[595] *Id.*

[596] *Id.* P 465.

[597] *Id.*

[598] *Id.*

[599] *Id.* P 466.

[600] Transmission Dependent Utility Systems at 18 (citing *Motor Vehicle Mfrs. Ass'n* v. *State Farm Mut. Auto Ins. Co.,* 463 U.S. 29, 43 (1983)).

Companies argue that Order No. 1000's assumption that this issue will be addressed under the regional processes is unsupported. They also argue that the lack of a specific requirement for stakeholder participation is inconsistent with some of the other interregional coordination requirements in Order No. 1000, including requirements related to joint evaluation of interregional projects and the determination of beneficiaries of such projects.

516. Moreover, Transmission Dependent Utility Systems argue that stakeholders must have a meaningful opportunity to participate in the early stages of the process for identifying and evaluating possible interregional solutions to transmission customer concerns. Similarly, PSEG Companies recommend that the Commission require that interregional coordination procedures include information on: (1) How transmission providers will facilitate stakeholder participation; (2) how market participants can propose ideas for cross-border projects and identify and submit concerns about problems in one region caused by activity in another (and how to address those concerns); and (3) how transmission providers will accommodate and track in a transparent manner all questions, comments, and other input from stakeholders regarding data posted on coordination activities, as well as transmission providers' responses.

517. Transmission Dependent Utility Systems also assert that Order No. 1000 fails to address their larger concern, which is that the interregional coordination processes fail to obligate public utility transmission providers to share with stakeholders the data exchanged among themselves, including study results, models, input data, and assumptions used in running those studies. Transmission Dependent Utility Systems are concerned that public utility transmission providers may contend that the obligation to share does not include load-serving customers. Further, Transmission Dependent Utility Systems state the Commission should clarify that the interregional planning data that is shared with load-serving entities must be sufficient to allow them to replicate the interregional planning study results, including models, base cases, data inputs, and assumptions. Transmission Dependent Utility Systems also believe it is important that benefit-to-cost analyses of interregional projects be transparent and verifiable to protect customers, ensure accuracy, and minimize *ex post facto* disputes regarding regional and interregional cost allocation.

iii. Commission Determination

518. First, we clarify for Transmission Dependent Utility Systems that each public utility transmission provider must provide stakeholders with a meaningful opportunity to provide input into the development of its interregional transmission coordination procedures before those procedures are submitted to the Commission in its compliance filing, whether those procedures are included in its OATT or reflected in an interregional transmission coordination agreement.[601] Accordingly, stakeholders must be afforded sufficient time to meaningfully comment on a public utility transmission provider's proposed interregional transmission coordination procedures as they are being developed.

519. In response to those petitioners that raise concerns regarding stakeholder participation in the interregional transmission coordination process, we reiterate the Commission's statement in Order No. 1000 that stakeholder participation in the consideration of interregional transmission facilities is an important component of interregional transmission coordination. Moreover, we also reiterate that stakeholders will have the opportunity to provide input with respect to the consideration of interregional transmission facilities when these facilities are being considered in the regional transmission planning process. As stated above, Order No. 1000 provides that only if an interregional transmission facility is selected in each region's transmission plan for purposes of cost allocation will that facility's cost be allocated to either region.[602] It is therefore through participation in the regional transmission planning process that stakeholders will have the primary opportunity to participate fully in the consideration of interregional transmission facilities. While nothing in Order No. 1000 prohibits an interregional transmission coordination process from providing for more direct stakeholder involvement in interregional transmission coordination, it may be the case that much of the interregional transmission coordination would occur through sharing computer modeling results regarding the effects and benefits of a proposed interregional transmission facility, which may be harder for a broad community of stakeholders to participate in than would face to face meetings be. If we are being asked to require there be in-person meetings for interregional transmission coordination with all stakeholders attending, we would be concerned about requiring a cumbersome process that could necessitate significant expense and travel time to multiple neighboring regions by the large number of stakeholders in each region. We continue to believe it is sufficient and appropriate to allow for consideration of stakeholder interests by requiring that any decision on interregional cost allocation be affirmed by each of the transmission planning regions involved.

520. For similar reasons, we decline to expand the requirements of Order No. 1000 regarding the types and sufficiency of interregional transmission coordination information to be exchanged between regions and provided to stakeholders. We therefore affirm Order No. 1000's requirement that, in order to facilitate stakeholder involvement, public utility transmission providers must, subject to appropriate confidentiality protections and CEII requirements, make transparent the analyses undertaken and determinations reached by neighboring transmission planning regions in the identification and evaluation of interregional transmission facilities.[603]

521. Further, we decline to adopt PSEG Companies' recommendation that the Commission require the interregional transmission coordination procedures to include information on how stakeholders in one transmission planning region can raise issues and solutions regarding activity in another transmission planning region. The regional transmission planning process already provides stakeholders with the opportunity to present such concerns, and we continue to believe that these concerns are best addressed in the first instance through the regional transmission planning process, particularly as the solution may not involve an interregional transmission facility.

522. In light of this, however, we clarify that each public utility transmission provider must describe in its OATT how its regional transmission planning process will enable stakeholders to provide meaningful and timely input with respect to the consideration of interregional transmission facilities. Moreover, as requested by PSEG Companies, we require that each public utility transmission provider must explain in its OATT how stakeholders and transmission developers can propose interregional transmission facilities for

[601] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 466.

[602] *Id.* P 465.

[603] *Id.*

the public utility transmission providers in neighboring transmission planning regions to evaluate jointly. This is consistent with Order No. 1000's requirement that on compliance, public utility transmission providers must describe the methods by which they will identify and evaluate interregional transmission facilities.[604]

IV. Cost Allocation

523. In Order No. 1000, the Commission required that each public utility transmission provider have in its OATT a method, or set of methods, for allocating the costs of new regional transmission facilities selected in the regional transmission plan for purposes of cost allocation (''regional cost allocation''); and that each public utility transmission provider within two (or more) neighboring transmission planning regions develop a method or set of methods for allocating the costs of new interregional transmission facilities that each of the two (or more) neighboring transmission planning regions selected for purposes of cost allocation because such facilities would resolve the individual needs of each region more efficiently or cost-effectively (''interregional cost allocation'').[605] The OATTs of all public utility transmission providers in a region must include the same cost allocation method or methods adopted by the region.

524. The regional and interregional cost allocation methods each must adhere to six regional and interregional cost allocation principles: (1) Costs must be allocated in a way that is roughly commensurate with benefits; (2) there must be no involuntary allocation of costs to non-beneficiaries; (3) a benefit to cost threshold ratio cannot exceed 1.25; (4) costs must be allocated solely within the transmission planning region or pair of regions unless those outside the region or pair of regions voluntarily assume costs; (5) there must be a transparent method for determining benefits and identifying beneficiaries; and (6) there may be different methods for different types of transmission facilities.[606] The Commission directed that, subject to these general cost allocation principles, public utility transmission providers in consultation with stakeholders would have the opportunity to agree on the appropriate cost allocation methods for their new regional and interregional transmission facilities, subject to Commission approval.[607] The Commission also found that if public utility transmission providers in a region or pair of regions could not agree, the Commission would use the record in the relevant compliance filing proceeding(s) as a basis to develop a cost allocation method or methods that meets the Commission's requirements.[608] Finally, the Commission emphasized that its cost allocation requirements are designed to work in tandem with its transmission planning requirements to identify more appropriately the benefits and the beneficiaries of new transmission facilities so that transmission developers, planners and stakeholders can take into account in the transmission planning process who would bear the costs of transmission facilities, if constructed.[609]

A. Legal Authority for Cost Allocation Reforms

1. Final Rule

525. In Order No. 1000, the Commission determined that its jurisdiction is broad enough to allow it to ensure that all beneficiaries of services provided by specific transmission facilities bear the costs of those benefits regardless of their contractual relationship with the owner of those transmission facilities.[610] The Commission stated that this comports fully with the specific characteristics of transmission facilities and transmission services, and that the provisions of Order No. 1000 are necessary to fulfill the Commission's statutory duty of ensuring rates, terms and conditions of jurisdictional service are just and reasonable and not unduly discriminatory or preferential.[611]

526. The Commission based its finding on the language of section 201(b)(1) of the FPA, which gives the Commission jurisdiction over ''the transmission of electric energy in interstate commerce.'' [612] The Commission concluded that its jurisdiction therefore extends to the rates, terms and conditions of transmission service, rather than merely transactions for such transmission service specified in individual agreements.[613] Moreover, the Commission found that section 201(b)(1) gives the Commission jurisdiction over ''all facilities'' for the transmission of electric energy, and this jurisdiction is not limited to the use of those transmission facilities within a certain class of transactions.[614] As a result, the Commission stated that it has jurisdiction over the use of these transmission facilities in the provision of transmission service, which includes consideration of the benefits that any beneficiaries derive from those transmission facilities in electric service regardless of the specific contractual relationship that the beneficiaries may have with the owner or operator of these transmission facilities.[615]

527. The Commission also explained that neither section 205 nor section 206 of the FPA state or imply that an agreement is a precondition for any transmission charges.[616] The Commission also concluded that cost allocation cannot be limited to voluntary arrangements because if it were the Commission could not address free rider problems associated with new transmission investment, and it could not ensure that rates, terms and conditions of jurisdictional service are just and reasonable and not unduly discriminatory.[617]

528. In addition, the Commission explained that its approach is consistent with the concept of cost causation, because a full cost causation analysis may involve ''an extension of the chain of causation'' [618] beyond those causes captured in voluntary arrangements. The Commission explained that in order to identify all causes, it is necessary to some degree to begin with their effects, i.e., the benefits that they engender and then work back to their sources.[619] The Commission noted that this point was acknowledged in the Seventh Circuit's characterization of cost causation in *Illinois Commerce Commission*.[620] The Seventh Circuit stated that:

> To the extent that a utility benefits from the costs of new facilities, *it may be said to have ''caused'' a part of those costs to be incurred,* as without the expectation of its contributions the facilities might not have been built, or might have been delayed.[621]

[604] *Id.* P 398.

[605] *Id.* P 482. For purposes of Order No. 1000, a regional transmission facility is a transmission facility located entirely in one region. An interregional transmission facility is one that is located in two or more transmission planning regions. A transmission facility that is located solely in one transmission planning region is not an interregional transmission facility. *Id.* P 482 n.374.

[606] *Id.* PP 622–93.

[607] *Id.* P 588.

[608] *Id.* P 482.

[609] *Id.* P 483.

[610] *Id.* P 531.

[611] *Id.*

[612] *Id.* P 532.

[613] *Id.*

[614] *Id.*

[615] *Id.*

[616] *Id.* P 533.

[617] *Id.* P 535.

[618] *Id.* P 536 (quoting *KN Energy,* 968 F.2d 1295 at 1302).

[619] *Id.*

[620] *Id.* P 537.

[621] *Id.* (quoting *Illinois Commerce Commission,* 576 F.3d at 476 (emphasis supplied)).

The court fully recognized that, to identify causes of costs, one must to some degree begin with benefits.[622]

529. Last, the Commission emphasized that its cost allocation reforms are a component of its transmission planning reforms, which require that, to be eligible for regional or interregional cost allocation, a proposed new transmission facility first must be selected in a regional transmission plan for purposes of cost allocation, which depends on a full assessment by a broad range of regional stakeholders of the benefits accruing from transmission facilities planned according to the reformed transmission planning processes.

2. Requests for Rehearing or Clarification

a. Petitioners' Arguments That the FPA Requires a Contract Before Costs Are Allocated

530. Several petitioners argue that the Commission does not have the jurisdiction to require that beneficiaries of service provided by specific transmission facilities bear the costs of those benefits regardless of their contractual relationship with the owner of those facilities.[623] They contend that the Commission's requirement to allocate costs without regard to whether there is a contract or service provided is inconsistent with the FPA.[624] For example, Ad Hoc Coalition of Southeastern Utilities and Large Public Power Council assert that the Commission has confused the FPA's expression of jurisdiction in section 201 with the grant of substantive authority, and that the Commission's interpretation of what section 201 allows would make sections 205 and 206 superfluous. They also assert that the Commission's view of section 201 would also render section 203 superfluous and allow the Commission to compel sales or purchases of jurisdictional facilities when the public interest required it.

531. National Rural Electric Coops state that a contractual relationship is required as a basis for a jurisdictional rate or charge. They maintain that in providing for Commission regulation of rates ''for or in connection with the transmission or sale of electric energy,'' the FPA ties the Commission's rate authority directly to the jurisdictional service provided by those public utilities.[625] They argue that where an entity takes no jurisdictional service from a public utility, the Commission cannot permit the public utility to collect charges from that entity. Several other petitioners make similar arguments.[626] Large Public Power Council argues that the natural implication of terms in section 205 and 206 such as ''made,'' ''demanded,'' ''received,'' ''observed,'' ''charged,'' or ''collected'' is that they pertain to rates assessed to utility customers in connection with an agreement to take service.[627]

532. Large Public Power Council argues that the approach taken in Order No. 1000 to cost allocation for new transmission development is at odds with the Commission's requirement that interstate gas pipeline projects be self-sustaining and not be subsidized by existing services. Large Public Power Council states that courts have held that the Natural Gas Act and the FPA should be interpreted similarly, and the Commission must explain substantial discrepancies.

533. Sacramento Municipal Utility District argues that if the rates that the Commission regulates are for transmission service, it logically follows that only customers who receive the transmission service can be charged for it. Vermont Agencies contend that even if the statute were ambiguous, it would still be unreasonable to allocate costs on the beneficiary theory because it would not follow logically from the Commission's acknowledgement that it only regulates the provision of transmission service.

534. Sacramento Municipal Utility District argues that the Commission never disputed its arguments that: (1) In theory, a utility could build a facility and then claim that because it provided a benefit to someone remote from the facility, that entity—customer or not—should bear some of the costs; and (2) it cannot force unwilling customers to pay for additional service.[628] Sacramento Municipal Utility District argues that Order No. 1000 allows ''beneficiaries'' of new transmission facilities to be charged even if they are not getting a new service.[629]

535. National Rural Electric Coops also argue that FPA sections 205 and 206 require that costs and benefits be fairly allocated between the two parties providing and receiving jurisdictional service. They contend that the fact that there may be third-party beneficiaries to an agreement does not change the analysis. They state that, even though other utilities may look more like transmission customers than entities that benefit indirectly from increased transmission capacity and are not subject to jurisdictional rates, this does not mean that those utilities have greater legal or contractual obligations.

536. Coalition for Fair Transmission Policy argues that the Commission is incorrect in finding that it has the legal authority to authorize public utilities to charge third party beneficiaries for transmission facilities because the issue has not been squarely addressed by the courts.[630] It asserts that the matter has not merited analysis or discussion because it is an undisputed maxim that lawful rates are founded on privity of contracts.

537. Several petitioners disagree that free rider problems are a basis for the cost allocation requirements established in Order No. 1000.[631] Southern Companies argue that under Order No. 1000, the mere potential of free riders is absolute poison to the justness and reasonableness of a cost allocation methodology. They contend that Order No. 1000 does not explain who these free riders may be, what benefits might be taken without compensation, or whether in the absence of the new transmission, they would require and financially support their own new transmission. Southern Companies add that Order No. 1000 does not explain why complaints under section 206 are

[622] *Id.*

[623] *See, e.g.,* Ad Hoc Coalition of Southeastern Utilities; Coalition for Fair Transmission Policy; Large Public Power Council; National Rural Electric Coops; New York ISO at 4 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 539); New York PSC; New York Transmission Owners; Northern Tier Transmission Group at 5 (citing *Atlantic City Elec. Co.* v. *FERC,* 295 F.3d 1, 8 (D.C. Cir. 2002) (stating that in the absence of statutory authority authorization for its act, an agency's action is plainly contrary to law and cannot stand)); Sacramento Municipal Utility District; Southern Companies at 96–97 (citing *Illinois Commerce Comm'n,* 576 F.3d 470 (2009); *Morgan Stanley Capital Group, Inc.* v. *Pub. Util. Dist. No. 1 of Snohomish County, Washington et al.,* 554 U.S. 527, 533 (2008); *Ottertail Power Co.* v. *United States,* 410 U.S. 366, 374 (1973); *In re Permian Basin Area Rate Cases,* 390 U.S. 747, 822 (1968); *United Gas Pipeline Co.* v. *Mobile Gas Service Corp.,* 350 U.S. 332, 343 (1956)); and Vermont Agencies at 6, 10 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 532).

[624] *See, e.g.,* Coalition for Fair Transmission Policy; Southern Companies; National Rural Electric Coops; and Ad Hoc Coalition of Southeastern Utilities.

[625] National Rural Electric Coops at 14 (quoting 16 U.S.C. 824d(a)).

[626] *See, e.g.,* National Rural Electric Coops; New York ISO; Northern Tier Transmission Group; Sacramento Municipal Utility District; Southern Companies; and Vermont Agencies.

[627] Large Public Power Council at 35.

[628] Sacramento Municipal Utility District at 9 (citing *Exxon Mobil Corp.* v. *FERC,* 430 F.3d 1166, 1176–77 (D.C. Cir. 2005)).

[629] Sacramento Municipal Utility District at 9 & n.4.

[630] Coalition for Fair Transmission Policy at 20 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 540).

[631] *See, e.g.,* Ad Hoc Coalition of Southeastern Utilities; Large Public Power Council; and National Rural Electric Coops.

insufficient for resolving free rider problems.

538. Southern Companies also assert that the FPA does not allow the allocation of costs to third-party non-customers because it does not allow the Commission to regulate cost allocations or rate structures that apply to the conveyance of abstract nonjurisdictional ''benefits'' other than electricity. Southern Companies assert that the FPA requires that cost allocations and rate structures must apply to the conveyance of benefits that are the actual use of transmission facilities or services (or support services required to provide the same). They argue that *Mobil Oil Corp.* v. *FPC* supports this conclusion.[632] In that case, the court found that the Commission exceeded its authority when it required cost allocation and rate structures for certain nonjurisdictional liquids as part of the transportation of natural gas.[633]

539. Sacramento Municipal Utility District argues that the Commission is incorrect in determining that it can require non-public utilities participating in a regional planning organization to accept an allocation of costs for new transmission facilities approved by the regional entity as a condition of reciprocity, even if they have no customer relationship with the transmission provider. It also states that the Commission's longstanding position is that without evidence that two systems are in fact acting as one, the Commission cannot mandate the use of a single joint rate.[634] Sacramento Municipal Utility District argues that if the Commission cannot mandate the use of joint rates, it cannot mandate that an entity pay the rates charged by a utility with which it has no contractual or tariff-based customer/provider relationship at all.

540. Several petitioners argue that the courts have rejected attempts to impose cost liability without a contract for Commission-jurisdictional service.[635] For example, Southern Companies and Coalition for Fair Transmission Policy argue that the entire design of the FPA is based on the premise that those who impose charges have a service relationship with those on whom charges are levied.[636] They assert that this is supported by the Supreme Court's finding in *Morgan Stanley,* where it stated that ''the regulatory system created by the FPA is *premised* on contractual agreements voluntarily devised by the regulated companies.'' [637] Coalition for Fair Transmission Policy states that in *Otter Tail Power Co.* v. *United States,* the Supreme Court wrote that Congress had rejected a pervasive regulatory scheme for transmission planning and cost allocation ''in favor of voluntarily contractual relationships.'' [638]

541. Ad Hoc Coalition of Southeastern Utilities also asserts that a utility's ability to collect rates is a matter of its contractual relationship with its customers, and the Commission's authority is limited to reviewing rates and, if unlawful, to remedying them. It asserts that this is apparent on the face of the FPA, and it has been a fundamental building block of energy law since the Supreme Court articulated the *Mobile-Sierra* doctrine.[639] Ad Hoc Coalition of Southeastern Utilities argues that the *Mobile-Sierra* doctrine makes it clear that the Commission's oversight of utility rates is subordinate to parties' contractual rights. It argues that the Commission errs in its attempt to distinguish *Mobile-Sierra* on the ground that ''we are dealing here with conditions under which costs can be recovered in rates, not conditions under which contracts can be altered.'' [640] Large Public Power Council makes similar arguments and also asserts that while the Commission has the authority to alter the terms of a contract for service under FPA section 206, subject to the ''public interest'' standard, it cannot establish a right to recover costs where no contractual authority exists.

542. National Rural Electric Coops state that a central holding of the *Mobile-Sierra* cases was that the Commission's authority to review and modify jurisdictional rates does not confer new rights on the public utilities subject to the Commission's jurisdiction. They argue that Order No. 1000 is inconsistent with *Mobile-Sierra* in concluding that costs may be allocated to entities in the absence of contractual privity because neither section 205 nor section 206 of the FPA state or imply that an agreement is a precondition for any transmission charges. National Rural Electric Coops maintain that it is impermissible for the Commission to infer authority to act based on the lack of an express Congressional denial of such authority.[641]

543. Several petitioners maintain that both court and Commission precedent show that a section 205 filing requires a customer or other contractual relationship between the filing utility and the ratepayer.[642] New York Transmission Owners assert that FPA section 205 does not authorize a utility to submit (and does not authorize the Commission to accept) a rate filing where the utility lacks a contractual or customer relationship with the entities to which the rate will be charged. They state that an administrative agency cannot exceed the authority granted to it by Congress and that the agency's role is not to preempt Congressional action or to fill gaps where it believes federal action is needed.[643]

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[632] 483 F.2d 1238 (D.C. Cir. 1973).

[633] Southern Companies at 100–101 (citing *Mobil Oil,* 483 F.2d 1238, 1248; also *Office of Consumers' Counsel* v. *FERC,* 655 F.2d 1132, 1148 (D.C. Cir. 1980)).

[634] Sacramento Municipal Utility District at 15 (citing *Ft. Pierce Utils. Comm'n* v. *FERC,* 730 F.2d 778 (D.C. Cir. 1984); *Richmond Power & Light* v. *FERC,* 574 F.2d 610 (D.C. Cir. 1978); *Alabama Power Co.* v. *FERC,* 993 F.2d 1557 (D.C. Cir. 1993); *Illinois Power Co.,* 95 FERC ¶ 61,183, at 61,144 (2002)).

[635] *See, e.g.,* Coalition for Fair Transmission Policy at 19–20 (citing *Morgan Stanley Capital Group, Inc.* v. *Public Utility District No. 1 of Snohomish County, Washington,* 554 U.S. 527, 533 (2008)); Illinois Commerce Commission; National Rural Electric Coops; New York PSC; Ad Hoc Coalition of Southeastern Utilities; and Large Public Power Council.

[636] Southern Companies at 97 (citing *Morgan Stanley Capital Group Inc.* v. *Pub. Util. Dist. No. 1 of Snohomish County, Washington,* 554 U.S. 527, 533 (2008); *Otter Tail Power Co.* v. *United States,* 410 U.S. 366, 374 (1973); *In re Permian Basin Area Rate Cases,* 390 U.S. 747, 822 (1968); *United Gas Pipeline Co.* v. *Mobile Gas Service Corp.,* 350 U.S. 332, 343 (1956)). *See also* Coalition for Fair Transmission Policy at 20–21.

[637] Southern Companies at 97–98 (quoting *Morgan Stanley,* 554 U.S. at 533 (2008) (citing and quoting with approval *Permian Basin Rate Cases,* 390 U.S. at 822); also citing *KN Energy, Inc.* v. *FERC,* 968 F.2d 1295, 1300 (D.C. Cir. 1992) (''[I]t has been traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them.'') (emphasis added); *Alabama Electric Cooperative, Inc.* v. *FERC,* 684 F.2d 20, 27 (D.C. Cir. 1982) (''Properly designed rates should produce revenue from each class of customers which match, as closely as practicable, the costs to serve each class or individual customer.'') (emphasis added)). *See also* Coalition for Fair Transmission Policy at 20–21; New York PSC at 6.

[638] Coalition for Fair Transmission Policy at 20–21 (quoting *Otter Tail Power Co.* v. *United States,* 410 U.S. 366, 374 (1973)).

[639] Ad Hoc Coalition of Southeastern Utilities at 68 (citing *United Gas Pipe Line Co.* v. *Mobile Corp.,* 350 U.S. 332 (1955 (*Mobile*); *FPC* v. *Sierra Pacific Co.,* 350 U.S. 348 (1956) (*Sierra*)); *see also* Northern Tier Transmission Group at 6.

[640] Ad Hoc Coalition of Southeastern Utilities at 70 (quoting Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 540).

[641] National Rural Electric Coops at 16 (citing *American Petroleum Institute* v. *EPA,* 52 F.3d 1113 (D.C. Cir. 1995); *Mobil Oil Corp.* v. *FPC,* 483 F.2d 1238 (DC Cir. 1973)).

[642] New York ISO at 4 (citing *In re Permian Basin Area Rate Cases,* 390 U.S. 747, 822 (1968)). *See also* New York ISO at 5–9 (citing *Midwest Indep. Transmission Sys. Operator, Inc.,* 131 FERC ¶ 61,173 (2010) and *Commonwealth Edison Co.,* 129 FERC ¶ 61,298 (2009), *order on reh'g,* 132 FERC ¶ 61,268 (2010)); Ad Hoc Coalition of Southeastern Utilities at 68–69 (citing 16 U.S.C. § 824d(a)); and New York Transmission Owners at 4.

[643] New York Transmission Owners at 5–6 (citing *California Indep. Sys. Operator Corp.* v. *FERC,* 372 F.2d 395, 398 (D.C. Cir. 2004) and *Office of Consumers' Counsel* v. *FERC,* 655 F.2d 1132, 1152 (DC Cir. 1980)).

544. Ad Hoc Coalition of Southeastern Utilities asserts that there is no Commission or court case approving an allocation of costs outside a contractual relationship. National Rural Electric Coops state that the Commission cited *Illinois Commerce Commission* for the proposition that to identify causes of costs, one must begin with benefits, but this statement does not address cost allocation in the absence of contractual privity when a non-customer is shown to benefit from a particular transmission project. They maintain that the court in *Illinois Commerce Commission* strongly suggested that costs must be recovered from customers when it noted that rates must ''reflect to some degree the costs actually caused by the *customer* who must pay them.'' [644] Southern Companies makes similar arguments. National Rural Electric Coops argue that Commission forbid cost allocations to non-customers when it refused to allow MISO to charge Green Mountain Energy Company (Green Mountain) for Seams Elimination Charge/Cost Adjustments/Assignment (SECA) costs under MISO's tariff because Green Mountain did not directly contract with MISO for transmission service, even though Green Mountain purportedly benefited from the transmission service.[645]

545. Vermont Agencies similarly argue that if the Commission is now asserting authority to allocate costs to non-customers, it failed to provide a reasonable basis for its change in course.[646] They state that *AEP* recognizes that utilities, in limited circumstances, can seek protection when they are forced to transmit for others, but an entity cannot build a transmission facility and then seek compensation for the benefit it provides to an entity that did not ask for it. Sacramento Municipal Utility District states that *AEP* provides no basis for charging an entity that simply benefits in some way from the new line's existence but has not caused loop flow through unscheduled deliveries.

546. Sacramento Municipal Utility District also reiterates its argument that the Commission relied upon cases for authority to allocate costs to non-customers that are inapt because they all involved situations where a customer/provider relationship existed.[647] It states that the Commission dismissed this argument in Order No. 1000 by stating that the issue was not before the court in any of those cases. It argues that the Commission did not defend its interpretation of these cases.[648] Moreover, Sacramento Municipal Utility District and Vermont Agencies assert that if the rationale for charging non-customers rests on cases the Commission now concedes are inapplicable, saying that those cases do not preclude it from allocating costs to non-customers does not answer just what does authorize the Commission to do so.

547. Sacramento Municipal Utility District also argues that the Commission's policy on cost allocation in Order No. 1000 would do more harm than good. For example, it contends that the risk of facing charges as an incidental beneficiary of a facility that a party did not want and will not use may discourage, rather than promote, regional cooperation.

b. Arguments That Order No. 1000's Cost Allocation Reforms Are Inconsistent With the Cost Causation Principle

548. Illinois Commerce Commission contends that the Commission misinterpreted the cost causation principle and failed to recognize the important distinction between cost causers and beneficiaries. It maintains that the applicable court decisions do not support equating cost causers and beneficiaries for purposes of cost allocation. It argues that the cost causation principle associates beneficiaries with cost causers only to the extent that the facilities might be delayed or not built without the revenues expected from them. Illinois Commerce Commission asserts that costs must be allocated primarily to such cost causers. Allocations to any other beneficiaries must be substantiated through an appropriate process.

549. Illinois Commerce Commission asserts that *Illinois Commerce Commission* makes it clear that when a line is planned to address the reliability concerns of one subregion of an RTO, there should be no cost allocations to others when the benefits to them are trivial or nonexistent.[649]

550. New York ISO states that transmission facilities may provide some greater or lesser degree of ''benefit'' to a broad range of system users, but showing that an entity receives some incidental benefit (based on a standard that has not yet been articulated) does not prove that the entity is receiving transmission service over that facility and should be assessed costs.

c. Arguments That the Commission Did Not Show That Existing Rates Are Unjust and Unreasonable

551. FirstEnergy Service Company and California ISO argue that the FPA does not authorize the Commission to require the filing of new rates without first finding that the existing rate is unjust, unreasonable, or unduly discriminatory or preferential. FirstEnergy Service Company maintains that the Commission concludes that the absence of clear cost allocation rules can impede the development of transmission facilities, which may adversely affect jurisdictional rates.[650] FirstEnergy Service Company argues that where no methodologies exist, the Commission cannot fulfill the basic requirement of section 206 that it find existing contracts or rates unjust, unreasonable, or unduly discriminatory or preferential. It maintains that section 206 applies to rates ''demanded, observed, charged or collected,'' not to rates that might apply to a future jurisdictional service.[651] FirstEnergy Service Company asserts that, if, on the other hand, there is an existing rate that applies to cost allocation for regional and interregional transmission facilities, then the Commission's conclusion that the absence of a rate is inapplicable, and the Commission does not find any such existing rates unjust or unreasonable. California ISO makes a similar argument. It also argues that the Commission cannot use section 206 to promote goals such as cost-effectiveness and transmission expansion, and rates are not unjust and unreasonable simply because another rate might be more just and reasonable.[652] California ISO states that its tariff already includes provisions that ensure the construction of needed

[644] National Rural Electric Coops at 20–21 (quoting *Illinois Commerce Commission,* 576 F.3d 470, 476 (7th Cir. 2009) (emphasis added by National Rural Electric Coops)).

[645] National Rural Electric Coops at 18 (citing *MISO,* 131 FERC ¶ 61,173 (2010) (SECA Order)).

[646] Vermont Agencies at 14–15 (citing *American Elec. Power Co.,* 49 FERC ¶ 61,377, at 62,381 (1986) (*AEP*); *Southern Cal. Edison Co.,* 70 FERC ¶ 61,087 (1995); *Midwest Indep. Transmission Sys. Operator, Inc.,* 131 FERC ¶ 61,173, at P 421 (2010)).

[647] Sacramento Municipal Utility District at 10–11 (citing *Midwest Indep. Transmission Sys. Operator, Inc.,* 109 FERC ¶ 61,168, P 60 (2004); *see also Midwest Indep. Transmission Sys. Operator, Inc.,* 113 FERC ¶ 61,194, P 1–4, 10 (2005); *Midwest Indep. Transmission Sys. Operator, Inc.,* 122 FERC ¶ 61,084, P22 (2008); *Midwest ISO Transmission Owners* v. *FERC,* 373 F.3d 1361 (D.C. Cir. 2004)).

[648] Sacramento Municipal Utility District at 11 (citing *Tennessee Gas Transmission Co.* v. *FERC,* 789 F.2d 61, 62–63 (D.C. Cir. 1986)).

[649] Illinois Commerce Commission contends that this is the case with respect to the projects at issue on remand in the *PJM Interconnection, LLC* matter in Docket No. EL06–121–006.

[650] FirstEnergy Service Company at 14 (quoting Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 579).

[651] FirstEnergy Service Company at 18.

[652] California ISO at 18 (citing *Duke Energy Trading and Marketing, LLC,* 315 F.3d 377, 382 (D.C. Cir. 2003)).

projects, and it takes cost-effectiveness into consideration when choosing projects.

552. FirstEnergy Service Company also asserts that the courts have admonished the Commission for seeking to impose new rates without first determining that the existing rate is unjust, unreasonable, or unduly discriminatory or preferential.[653] It cites *Public Service Commission of New York* v. *FERC* in which the court disagreed with the Commission that it could act under section 4 of the NGA rather than section 5 in finding that an existing zone allocation in the utility's rates was unlawful and prescribing a new allocation because the utility had proposed a rate increase under section 4 of the NGA.[654] FirstEnergy Service Company states that the court reversed the Commission's decision because the Commission did not make a finding under section 5 of the NGA. FirstEnergy Service Company also cites other cases in which it states that the court rejected Commission filing requirements as an impermissible attempt to avoid the strictures of sections 4 and 5 of the NGA.[655]

553. FirstEnergy Service Company argues that the Supreme Court has found that the right to file new rates and contracts belongs solely to public utilities under the FPA.[656] It disagrees with the Commission's assertion that it is setting standards for filings under section 205 rather than interfering with public utilities' rights to file new rates,[657] it argues that Order No. 1000 directs transmission providers to amend their tariffs to include cost allocation provisions for regional and interregional facilities. FirstEnergy Service Company contends that the Commission may issue guidelines that will be used to determine whether future rates for regional and interregional facilities will be just and reasonable, but section 205 does not permit it to compel filings of rates or contracts.

554. Ad Hoc Coalition of Southeastern Utilities argues that the Commission cannot support its determination by simply finding that rates will be unjust and unreasonable without a cost allocation mechanism. As support for this position, Ad Hoc Coalition of Southeastern Utilities argues that the Commission's authority over practices affecting rates under section 206 is limited to practices that directly affect rates,[658] and effectively requires utilities to pay transmission developers for investments that the utilities do not use indirectly affects rates for jurisdictional service. Large Public Power Council makes similar arguments.

3. Commission Determination

555. Many petitioners object to the Commission's cost allocation reforms in Order No. 1000 based on what they consider to be fundamental principles concerning both the Commission's jurisdiction as well as the nature of transmission operations and the benefits they provide. Many of the arguments raised by petitioners share common themes, and we thus will address them collectively as far as possible. In order to do this comprehensively, we think it is important first to state briefly what the Commission did, and did not, require in Order No. 1000 with respect to cost allocation and to address some of the basic principles that inform those decisions.

556. The cost allocation reforms in Order No. 1000 are grounded in our determination that it is necessary to establish a closer link between regional transmission planning and cost allocation, both of which involve the identification of beneficiaries of new transmission facilities. Planning of new transmission facilities in a regional transmission planning process involves assessing how such facilities will affect the existing transmission grid and how they will benefit users of the grid within the relevant region.[659] Cost allocation for new transmission facilities that are selected in a regional transmission plan for purposes of cost allocation similarly involves assigning the costs of those facilities in a manner that accounts for the identified benefits. Recognizing this relationship, the Commission found that the lack of clear ex ante cost allocation methods that identify beneficiaries of proposed regional and interregional transmission facilities may be impairing the ability of public utility transmission providers to implement more efficient or cost-effective transmission solutions identified during the transmission planning process. The Commission also found that linking transmission planning and cost allocation through the regional transmission planning process would increase the likelihood that transmission facilities in regional transmission plans are constructed.

557. This emphasis on a closer link between regional transmission planning and cost allocation also informs the cost allocation principles that the Commission adopted in Order No. 1000. The Commission found that in light of the need for a closer link between regional transmission planning and cost allocation, allowing one region to allocate costs unilaterally to entities in another region would impose too heavy a burden on stakeholders to actively monitor transmission planning processes in numerous other regions, from which they could be identified as beneficiaries and be subject to cost allocation. The Commission also stated that if it expected such participation, the resulting regional transmission planning processes could amount to interconnectionwide transmission planning with corresponding cost allocation. The Commission stated clearly that Order No. 1000 does not require either interconnectionwide transmission planning or interconnectionwide cost allocation. We reaffirm these findings here, as discussed further below with respect to Cost Allocation Principle 4.[660]

558. Against this backdrop, we note the actions that the Commission took in Order No. 1000 with respect to cost allocation are based on its jurisdiction under section 201(b)(1) of the FPA over the transmission of electric energy in interstate commerce and the facilities for such transmission and its duty to exercise it authority under sections 205 and 206 of the FPA to ensure that Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential.[661] The nature and scope of this authority must be viewed in the context of the specific characteristics of transmission facilities

[653] FirstEnergy Service Company at 16 (citing *Western Resources, Inc.* v. *FERC,* 9 F.3d 1568, 1578 (D.C. Cir. 1993); *Tenn. Gas Pipeline Co.* v. *FERC,* 860 F.2d 446 (D.C. Cir. 1988); *Northern Natural Gas Co.* v. *FERC,* 827 F.2d 779 (D.C. Cir. 1987); *Sea Robin Pipeline Co.* v. *FERC,* 795 F.2d 182 (D.C. Cir. 1986); *ANR Pipeline Co.* v. *FERC,* 771 F.2d 507 (D.C. Cir. 1985); *Panhandle E. Pipe Line Co.* v. *FERC,* 613 F.2d 1120 (D.C. Cir. 1980)).

[654] FirstEnergy Service Company at 16–17 (citing *Public Service Commission of New York* v. *FERC,* 642 F.2d 487 at 1344–45). FirstEnergy Service Company states that although the Court was describing the NGA, the FPA and NGA are interpreted in parallel. *FPC* v. *Sierra Pacific Power Co.,* 350 U.S. 348, at 353 (1956).

[655] FirstEnergy Service Company at 17 (citing *Public Service Commission of New York* v. *FERC,* 866 F.2d 487 (D.C. Cir. 1989) and *Consumers Energy Co.* v. *FERC,* 226 F.3d 777 (6th Cir. 2000)).

[656] FirstEnergy Service Company at 13 (quoting *United Gas Pipeline Co.* v. *Mobile Gas Ser. Co.,* 350 U.S. 332 at 341).

[657] FirstEnergy Service Company at 18 (quoting Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 547).

[658] Ad Hoc Coalition of Southeastern Utilities at 73 (citing *California Independent System Operator* v. *FERC,* 372 F.3d at 403).

[659] Users of the regional transmission grid could be, for example, public utility transmission providers that may effectively rely on transmission facilities of another transmission provider in order to provide transmission service, whether or not there is a service agreement between those public utility transmission providers.

[660] *See* discussion *infra* at section 0.

[661] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at PP 532, 535.

and their operation, among other considerations.[662]

559. Transmission operations are characterized by a number of unique features that are essential for understanding the Commission's position, and therefore they merit summarizing here. Electric energy does not travel on a preset path but rather along all available pathways in accordance with the laws of physics.[663] Continuous fluctuations in the demand for power and in generation operations affect power flows throughout the transmission grid. This means that electric energy received by an individual customer at any one time could be delivered over any number of transmission facilities that constitute the transmission grid. Changes in demand for or supply of electricity at any point in the system will change flows on all the transmission lines to varying degrees, often in ways that are not easily controlled.[664]

560. The courts have recognized this fundamental fact and have acknowledged that it has important implications for the Commission's regulation of transmission service. The DC Circuit has stated:

> * * * In order to determine a utility's cost of providing a transmission service, the Commission typically treats a transmission network * * * as an integrated system. In other words, all of the individual facilities used to transmit electricity are treated as if they were part of a single machine. The Commission takes this approach on the ground that a transmission system performs as a whole; the availability of multiple paths for electricity to flow from one point to another contributes to the reliability of the system as a whole. This principle has a strong basis in the physics of electrical transmission for there is no way to determine what path electricity actually takes between two points or indeed whether the electricity at the point of delivery was ever at the point of origin.
>
> As a corollary, in determining permissible prices for transmission services, the Commission treats each transmission customer not as using a single transmission path but rather as *using the entire transmission system*.[665]

In other words, in the case of transmission, there is only one service—service over the entire grid.[666]

561. The Commission appreciates that these prior decisions related to transmission rates for a single public utility transmission provider's facilities. However, the principle underlying those decisions is equally applicable across larger regions of the transmission system. Given the physics of power flows, and the ownership of transmission facilities in the United States, the actual transmission facilities that are affected by a particular transaction are owned by multiple, interconnected transmission providers irrespective of whether the transaction involves a single contract for transmission service with one of the owners of the transmission facilities or multiple contracts with all of the owners of the transmission facilities along a contract path. That is, the transmission grid constitutes a common infrastructure, ''a cohesive network moving energy in bulk.'' [667] Entities that contract for service on the transmission grid cannot ''choose'' to affect only the transmission facilities for which they have entered into a contract, as some petitioners contend. Similarly, those entities cannot claim that they are not using or benefiting from such transmission facilities simply because they did not enter a contract to use them.

562. We also note that in an interconnected electric transmission system, the enlargement of one path between two points can provide greater system stability, lower line losses, reduce reactive power needs, and improve the throughput capacity on other facilities. Given the nature of transmission operations, it is possible that an entity that uses part of the transmission grid will obtain benefits from transmission facility enlargements and improvements in another part of that grid regardless of whether they have a contract for service on that part of the grid and regardless of whether they pay for those benefits. This is the essence of the ''free rider'' problem the Commission is seeking to address through its cost allocation reforms.[668] Any individual beneficiary of a new transmission facility has an incentive to defer investment in the anticipation that other beneficiaries in the region will value the project enough to fund its development. This can lead to situations in which no developer moves forward, adversely affecting development of transmission facilities and, as a result, rates for jurisdictional services.

563. The Supreme Court has stated that the Commission's jurisdiction is ''to follow the flow of electric energy, an engineering and scientific, rather than a legalistic or governmental, test.'' [669] Indeed, the Supreme Court described the entire FPA as ''couched largely in the technical language of the electric art.'' [670]

564. Despite these considerations, many petitioners argue that the costs of new transmission facilities can only be allocated within a preexisting contractual relationship. These arguments are based on the assumption that only preexisting contracts define jurisdictional transmission service. In relying exclusively on contracts to perform this role, petitioners are advocating a legalistic test for assessing the scope of the Commission's jurisdiction that is inconsistent with the Supreme Court's interpretation of the FPA in *Connecticut Light & Power Co.* Contracts do not reflect the actual flow of electric energy on the transmission grid. Nor do contracts define or limit the benefits that an entity receives from its use of the transmission grid. To argue that costs for new transmission facilities can be allocated only through preexisting contractual relations means that some entities that will benefit from those transmission facilities simply cannot be allocated costs roughly commensurate with the benefits that they receive. This is inconsistent with the well-established Commission and judicial interpretation of the FPA and contrary to the requirement that transmission rates be just and

[662] As discussed further below, the Commission finds that there is a need to balance a number of factors to ensure that the reforms adopted in Order No. 1000 achieve the goal of improved planning and cost allocation for transmission in interstate commerce. *See* discussion *infra* at section 0.

[663] An interconnected AC transmission grid essentially functions as a single piece of equipment. *See, e.g., Tampa Electric Co.,* 99 FERC ¶ 61,192, at 61,796 (2002).

[664] *See, e.g.,* Jack A. Casazza, *Transmission Access and Retail Wheeling: The Key Questions, in Electricity Transmission Pricing and Technology* 81 (Michael Einhorn and Riaz Siddiqi eds., 1996); Narain G. Hingorani, *Flexible AC Transmission System (Facts), in id.* 242; Karl Stahlkopf, *The Second Silicon Revolution, in id.* 263.

[665] *Northern States Power Co.* v. *FERC,* 30 F.3d 177, 179 (DC Cir. 1994) (emphasis supplied) (*Northern States*); *see also Western Massachusetts Electric Company* v. *FERC,* 165 F.3d 922, 927 (DC Cir. 1999) (stating that ''[w]hen a system is integrated, any system enhancements are presumed to benefit the entire system'').

[666] We note that this principle is not, in itself, determinative of what would constitute a just and reasonable cost allocation method. For example, a regional cost allocation method must satisfy the principles set forth in Order No. 1000 and affirmed here, including that the costs of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is roughly commensurate with estimated benefits. *See, e.g.,* Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 622.

[667] *Public Serv. Co. of Colo.,* 62 FERC ¶ 61,013, at 61,061 (1993).

[668] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at PP 534–35.

[669] *Connecticut Light & Power Co.* v. *F.P.C.,* 324 U.S. 515, 529 (1945) (*Connecticut Light & Power Co.*).

[670] *Id.*

reasonable and not unduly discriminatory or preferential.[671]

565. This explains why the cost allocation provisions of Order No. 1000, which seek to allocate costs to beneficiaries in a region roughly commensurate with benefits they receive, are consistent with the statement in *Illinois Commerce Commission* that ''[a]ll approved rates [must] reflect to some degree the costs actually caused by the customer who must pay them.'' [672] Petitioners argue that because the court in *Illinois Commerce Commission* used the word ''customer'' in the quote above, it suggests that costs must be recovered from entities that have a preexisting contractual relationship with the entity seeking the cost allocation. However, given the nature of cost causation itself, some entities that actually cause costs would not be required to pay them if they could utilize the absence of a contractual relationship to shield themselves from an allocation of costs. Rather than contractual relationships, the benefits received by users of the regional transmission grid provide a basis for how costs should be allocated. Petitioners' argument would inappropriately revise the *Illinois Commerce Commission* court's explanation that the cost causation principle requires that ''all approved rates [must] reflect to some degree the costs actually caused by the customer who must pay them'' by adding a further requirement that the customer also agree to be responsible for such costs. The court did not, however, reach such a conclusion. We thus reject the claim by Ad Hoc Coalition of Southeastern Utilities that the Commission's adherence to the cost causation principle is subordinate to parties' contractual rights.

566. Moreover, our interpretation of the court's use of ''customer'' in *Illinois Commerce Commission* is consistent with the statements that the court makes immediately thereafter. The court first notes that compliance with the principle involved is evaluated '' 'by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party.'' ' [673] The court did not condition its statement on a need for a preexisting contractual relationship. Rather, the court allowed for a full comparison of costs for any party that imposed burdens on, and benefited from enhancement of, the network transmission grid. Furthermore, the court follows this by stating that ''[t]o the extent that a utility benefits from the costs of new facilities, it may be said to have 'caused' a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed.'' [674] That is precisely the role that the Commission's cost allocation reforms play within the context of its planning reforms. That the lack of *ex ante* cost allocation methods that identify the beneficiaries of proposed regional and interregional transmission facilities may be impairing the ability of public utility transmission providers to implement more efficient or cost-effective transmission solutions identified in the transmission planning process.[675]

567. Some petitioners also argue that the Supreme Court's statement in *Morgan Stanley* that ''the regulatory system created by the [FPA] is premised on contractual agreements voluntarily devised by the regulated companies'' [676] means that a preexisting contractual relationship is an essential precondition of cost allocation. Given the nature of transmission grid operations, we disagree that this statement by the Supreme Court means that contracts, which will not fully reflect how transmission facilities are impacted by power flows, are the only device that defines what rates are just and reasonable and not unduly discriminatory or preferential. We do not read the importance that the Supreme Court ascribes to voluntary contracts in *Morgan Stanley* to imply that entities that use the transmission grid are entitled to structure their contractual arrangements so that they are shielded from paying costs that are roughly commensurate with the benefits that they receive. In any event, *Morgan Stanley* never stated that, by refusing to sign a contract, an entity benefiting from another's improvement of the regional transmission grid can limit its obligation to something less than an obligation to pay for all benefits that it receives.

568. The obligation under the FPA to pay costs allocated under a regional or interregional cost allocation method is imposed by a Commission-approved tariff concerning the charges made by a public utility transmission provider for the use of the public utility transmission provider's facility. Such use is voluntary, and it does not become less so because it is determined in part by immutable laws of physics. Voluntary use therefore also entails voluntary acceptance of the terms and conditions of use set forth in the tariff, including an applicable cost allocation.

569. We disagree with National Rural Electric Coops' argument that Order No. 1000 is conferring new rights on public utility transmission providers. We are not conferring new rights on public utility transmission providers when we seek to ensure that they can allocate the costs of their new transmission facilities to the beneficiaries of those facilities. Nor are we claiming a power based solely on the fact that there is not an express withholding of such power, as National Rule Electric Coops claim. We are acting under the provisions of section 206 of the FPA applied in accordance with the reasoning that we have set forth both here and in Order No. 1000.

570. In response to Large Public Power Council's argument that the references in sections 205 and 206 to rates ''made,'' ''demanded,'' ''received,'' ''observed,'' ''charged,'' or ''collected'' pertain to rates assessed to utility customers in connection with an agreement to take transmission service, we reiterate the Commission's finding in Order No. 1000 that ''nothing in these sections precludes flows of funds to public utility transmission providers through mechanisms other than agreements between the service provider and the beneficiaries of those transmission facilities.'' [677] As explained in further detail above, an entity that uses the transmission grid will necessarily use transmission facilities owned by multiple owners, and the FPA permits a public utility transmission provider to charge for the costs of using its transmission facilities.

571. Contrary to the claim of National Rural Electric Coops, all cost allocation contemplated by Order No. 1000 pertains to rates ''for or in connection with the transmission * * * of electric energy.'' Order No. 1000 does not permit a public utility transmission provider to collect charges other than in connection with the use of the transmission grid. In suggesting that it does, National Rural Electric Coops misconstrues the criteria for identifying the scope of transmission usage. That scope is defined by the transmission grid operations, not simply the terms of individual contracts, which can diverge

[671] We also note that Order No. 1000 states: ''Neither section 205 nor section 206 of the FPA state or imply that an agreement is a precondition for any transmission charges. These statutory provisions speak of rates and charges that are 'made,' 'demanded,' 'received,' 'observed,' 'charged,' or 'collected' by a public utility.'' Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 533.

[672] *Illinois Commerce Commission,* 576 F.3d 470 at 476 (internal citations omitted).

[673] *Id.* (internal citations omitted).

[674] *Id.*

[675] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 499.

[676] *Morgan Stanley,* 554 U.S. at 533.

[677] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 533.

from the underlying transmission grid operations. It is the purpose of the cost allocation method or methods required by Order No. 1000 to align cost responsibility with the reality of transmission grid operations in the case of new transmission facilities selected in the regional transmission plan for purposes of cost allocation.[678]

572. Moreover, contrary to Large Public Power Council's argument, the cost allocation provisions of Order No. 1000 do not alter any existing contract provisions governing the use of existing transmission facilities and, therefore, are not inconsistent with *Mobile-Sierra* doctrine regarding revision of contracts. Order No. 1000 requires each public utility transmission provider to revise its OATT to include a method, or set of methods, for allocating the costs of new transmission facilities selected in a regional transmission plan for purposes of cost allocation—not transmission facilities already in service.

573. We reject the characterization of the cost allocation requirements of Order No. 1000 as authorizing allocation of costs to third-party beneficiaries. Order No. 1000 authorizes allocation of costs to entities that benefit in their own right from new transmission facilities selected in a regional transmission plan for purposes of cost allocation. To the extent that an entity is not required to pay for a benefit that it receives, it is a free rider not a third party beneficiary. The fact that a free rider benefits from a transaction between two other entities does not make it a third party beneficiary, which is a legal concept that refers to parties that have a right to a benefit under a contract between two other entities. Such rights are not at issue here.

574. We thus also disagree with National Rural Electric Coops that Order No. 1000 suggests that charges could be imposed on ''third party beneficiaries'' such as ''[s]teel producers, crane operators, and wind turbine manufacturers who may find more customers for their products and services as a result of increased transmission capacity * * *.''[679] We note that Regional Cost Allocation Principle 1 provides that:

In determining the beneficiaries of interregional transmission facilities, transmission planning regions may consider benefits including, but not limited to, those associated with maintaining reliability and sharing reserves, production cost savings and congestion relief, and meeting Public Policy Requirements.[680]

While this statement explicitly is not intended to be an exhaustive recitation of possible benefits, our expectation is that additional types of benefits would be ''in connection with'' transmission of electric energy. We do not intend that these benefits should include such things as increased sales of goods and services used in the construction of new transmission facilities.

575. Likewise, in response to Southern Companies, Order No. 1000 does not authorize cost allocations or rate structures that apply to conveyance of ''benefits [that] are not the actual use of transmission facilities or services (or support services required to provide same).''[681] We see no inconsistency between the cost allocation provisions of Order No. 1000 and *Mobil Oil Corp.* v. *FPC,* as Southern Companies claim. In that case, the court held that the Commission had jurisdiction over rates for the transportation of natural gas on an interstate pipeline but not over rates for the transportation of certain non-jurisdictional liquid hydrocarbons that were also transported on the pipeline. The court held that the Natural Gas Act restricted the Commission's jurisdiction to rates for natural gas transportation.[682] Southern Companies maintains that Order No. 1000 authorizes rates for non-jurisdictional benefits that are analogous to the non-jurisdictional liquid hydrocarbons in *Mobil Oil Corp.* v. *FPC.* However, Order No. 1000 does not do this. It authorizes cost allocation for benefits consistent with Regional Cost Allocation Principle 1, which explicitly refers to matters that are subject to Commission jurisdiction. For the same reasons, we disagree with the claim of Vermont Agencies that Order No. 1000 authorizes allocation of costs to persons that benefit in some way from the existence of a transmission facility even if they use no transmission service at all.

576. In response to Southern Companies regarding free riders, we note that free riders for purposes of Order No. 1000 are entities who do not bear cost responsibility for benefits that they receive in their use of the transmission grid, specifically benefits they receive from new transmission facilities selected in a regional transmission plan for purposes of cost allocation. Such benefits include the traditional benefits that transmission facilities can provide, such as lowered congestion, increased reliability, and access to generation resources. Southern Companies state that the Commission does not address whether such entities would pursue or support new transmission facilities in the absence of a transmission project that is entitled to cost allocation, but this overlooks the purpose of the cost allocation requirements of Order No. 1000. They are intended to promote regional and interregional transmission planning that facilitates more efficient or cost-effective transmission infrastructure development. The lack of *ex ante* cost allocation methods that identify the beneficiaries of proposed regional and interregional transmission facilities may be impairing the ability of public utility transmission providers to implement more efficient or cost-effective transmission solutions identified in the transmission planning process. For this reason, individual complaints under section 206 of the FPA would not suffice to overcome the free rider problem because litigating complaints burdens and unduly delays the transmission planning process. Individual complaint procedures thus do not permit effective transmission planning.

577. The Commission has not confused the FPA's expression of jurisdiction in section 201 with a grant of substantive authority. Ad Hoc Coalition of Southeastern Utilities and Large Public Power Council argue that according to the Commission's rationale, its jurisdiction under section 201 over transmission service and transmission facilities would also cover the matters for which specific authority is granted in sections 205 and 206, as well as section 203, thereby rendering those sections superfluous. As the Commission found in Order No. 1000, section 201 simply sets forth the facilities and transactions in interstate commerce that are subject to the Commission's jurisdiction under Part II of the FPA. Our authority to act in Order No. 1000 on matters subject to our jurisdiction arises under section 206 of the FPA, specifically our authority to establish requirements regarding transmission planning and cost allocation which are practices affecting rates. The Commission's jurisdiction permits that authority to be applied in a way that follows ''the flow of electric energy, an engineering and scientific, rather than a legalistic or governmental, test,''[683] and Order No. 1000's

[678] As explained above, providing for such cost allocation will help to ensure that rates are just and reasonable and not unduly discriminatory or preferential as required by section 205 of the FPA. 16 U.S.C. 824d.

[679] National Rural Electric Coops at 21.

[680] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 622.

[681] Southern Companies at 99.

[682] *Mobil Oil Corp.* v. *FPC,* 483 F.2d 1238, 1246–47 (D.C Cir. 1973).

[683] *Connecticut Light & Power Co.,* 324 U.S. at 529.

application of the principle of cost causation is a reasonable exercise of that authority. However, such action is not based directly on section 201. It is based on section 206, which we apply to matters that are within the scope of our jurisdiction set forth in section 201. Moreover, we disagree with those petitioners that argue that our interpretation of section 201 in Order No. 1000 could render either section 203, section 205, or section 206 of the FPA superfluous, because as we explain above, section 201 sets forth the subject matter over which the Commission exercises its jurisdiction pursuant to those other sections.

578. Contrary to Large Public Power Council's contention, the cost allocation requirements of Order No. 1000 are not at odds with the Commission's policy on interstate gas pipeline development regarding subsidization of development by existing shippers. The requirements of Order No. 1000 are based on the principle of cost causation, which requires that costs be allocated in a way that is roughly commensurate with benefits. The principle of cost causation is intended to prevent subsidization by ensuring that costs and benefits correspond to each other. Indeed, in seeking to eliminate free riders on the transmission grid, Order No. 1000 seeks to eliminate a form of subsidization, as free riders by definition are entities who are being subsidized by those who pay the costs of the benefits that free riders receive for nothing.

579. We disagree with Sacramento Municipal Utility District's assertion that Order No. 1000 fails to prevent a utility from building a transmission facility and then simply claiming that a remote entity receives benefits from it and thus must bear some of the costs. Under Order No. 1000, for a regional cost allocation method to apply to a new regional or interregional transmission facility, the transmission facility must first be selected in a regional transmission plan or plans for purposes of cost allocation. This means that the public utility transmission providers in a region, in consultation with stakeholders, have evaluated a given facility and determined that it provides benefits that merit cost allocation under a regional method. As such, a developer of a transmission facility will not be entitled to recover costs from other entities without its facility being subject to the requirements of the regional transmission planning process, including the selection of its facility in the regional transmission plan for purposes of cost allocation.

580. We also disagree with Sacramento Municipal Utility District that Order No. 1000 forces unwilling customers to pay for additional transmission service or to be charged even if they are not getting a new transmission service. Order No. 1000 requires that new costs be allocated in a way that is roughly commensurate with the benefits derived from the new transmission facilities that are eligible for cost allocation in accordance with Order No. 1000. As discussed above, entities that receive benefits from these facilities in the course of their use of the transmission grid cannot be characterized as ''unwilling customers.'' New York ISO notes that benefits come in various degrees, and it maintains that entities should not be charged for an ''incidental benefit.'' But again, Order No. 1000 requires that costs be allocated in a way that is roughly commensurate with benefits, and the court stated in *Illinois Commerce Commission* that entities cannot be allocated costs for benefits that are trivial in relation to those costs.[684] All cost allocation methods will be subject to Commission review and approval, and issues related to the appropriateness of a particular method or methods can be raised at that time.

581. Sacramento Municipal Utility District's argument that joint rates are necessary for cost recovery in the case of a regional cost allocation under Order No. 1000, describes a false dilemma. It argues that without evidence that two systems are in fact acting as one, the Commission cannot mandate the use of a single joint rate, and if it cannot mandate the use of joint rates, it cannot mandate that an entity pay the rates charged by a utility with which it has no contractual or tariff-based customer/provider relationship. However, our position regarding the role of preexisting contractual relationships goes to the problem of cost allocation, not cost recovery, which Sacramento Municipal Utility District focuses on when it speaks of the payment of charges and which Order No. 1000 does not address.[685] Moreover, Order No. 1000 requires that the tariffs of transmission providers in a region contain the regional cost allocation method or methods, which means that in any event, there will be a tariff basis for implementing a cost allocation. We thus reject the claim that a regional cost allocation could be implemented only through a joint rate.

582. Turning to arguments that Order No. 1000 represents a change in policy expressed in prior cases, we disagree with National Rural Electric Coops' contention that the cost allocation provisions of Order No. 1000 are contradicted by the Commission's refusal to allow MISO to charge Green Mountain for SECA costs under MISO's tariff because Green Mountain did not directly contract with MISO for transmission service. In the SECA Order, the Commission found merely that Green Mountain's affiliate BP Energy, not Green Mountain, was responsible for paying the SECA charges because the contract between the affiliate and Green Mountain stipulated that BP Energy was responsible for paying MISO for network transmission service.[686] The Commission found that since SECA charges were intended to be surcharges assessed to the transmission customer taking transmission service, and BP Energy, not Green Mountain, was taking transmission service from MISO, BP Energy was responsible for paying the SECA charges.[687] The Commission emphasized on rehearing of the SECA Order that MISO's tariff specifically provided for its transmission customers to pay SECA charges, and therefore the fact that BP Energy was the transmission customer, not Green Mountain, was pivotal to the Commission's conclusion that BP Energy was responsible for the SECA charges.[688] This conclusion was based on a reading of the requirements of the MISO tariff, and as such, it cannot be read as establishing general principles regarding the authority of a public utility transmission provider to collect charges for the transmission of electric energy, as National Rural Electric Coops argue.

583. Vermont Agencies and Sacramento Municipal Utility District argue that the cost allocation reforms of Order No. 1000 represent a change in policy from the position that the Commission took in *AEP,* and they maintain that the Commission has failed to explain this change in policy. *AEP* dealt with unintended loop flows on existing facilities, which the Commission viewed as an operational issue that ''in the first instance'' was to be dealt with by ''the interconnected parties'' establishing ''mutually acceptable operating practices.''[689] The Commission also stated that if the party complaining of unintended loop flows on its facilities could show that they created ''a burden on its system, [it] can file a transmission service rate for

[684] *Illinois Commerce Commission,* 576 F.3d at 476.

[685] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 563.

[686] SECA Order, 131 FERC ¶ 61,173 at P 422.

[687] *Id.* P 423.

[688] 136 FERC ¶ 61,244 at P 205.

[689] *AEP,* 49 FERC ¶ 61,377, at 62,381.

Commission consideration which would account for any unauthorized loop flows.'' [690] Vermont Agencies and Sacramento Municipal Utility District describe Order No. 1000 as containing a policy change on this point because in their view, the Commission maintains in Order No. 1000 that ''it could allocate the costs of new transmission facilities to entities that somehow benefit from their existence—whether or not they take service from the utility,'' whereas *AEP* ''addresses the issue of compensation where the utility is involuntarily forced to provide service.'' [691] However, we see no fundamental difference between *AEP* and Order No. 1000 precisely because individual owners of facilities on an interconnected grid ''can file a transmission service rate for Commission consideration'' under *AEP.* Additionally, it is because such owners will often forgo grid enlargements that benefit many owners of other facilities who will not pay for these enlargements that Order No. 1000 seeks to ensure that the former may be compensated through a cost allocation to the latter.

584. We also disagree with Vermont Agencies and Sacramento Municipal Utility District that Order No. 1000 represents a change in policy because the Commission has ''rejected assessment of charges'' in situations such as that presented in *AEP.*[692] The Commission did not reject an assessment of charges in *AEP.* It stated that the operational issue in question was in the first instance to be dealt with through mutually acceptable operating practices, but a rate filing would be appropriate if the loop flows created a burden on the system. Moreover, Order No. 1000 does not deal with operating problems on existing transmission facilities but rather solely with benefits to be derived from new transmission facilities that regional participants themselves select as having broad regional benefits, and it deals with cost allocation for such new facilities as integral to transmission planning. In this respect, Order No. 1000 does not express a change a policy position taken in *AEP* because *AEP* does not deal with planning and cost allocation for new transmission facilities and expresses no policy with regard to these matters.

585. In response to Illinois Commerce Commission's argument that beneficiaries are to be associated with cost causers only to the extent that transmission facilities might be delayed or not built without the revenues expected from them, we note that it is for this reason that the cost allocation requirements of Order No. 1000 are necessary. By allocating costs in a way that is roughly commensurate with benefits, the requirements help to ensure that more efficient and cost-effective transmission solutions are implemented and that this occurs without undue delay. In addition, one of the purposes of the regional transmission planning process is to identify the beneficiaries of a proposed transmission facility. This addresses Illinois Commerce Commission's concern about the substantiation of benefits through an appropriate process.

586. We also disagree with Sacramento Municipal Utility District that the Commission's position on cost allocation is likely to do more harm than good by discouraging regional cooperation. On the contrary, Order No. 1000 is intended to encourage the development of more efficient and cost-effective transmission solutions to regional transmission needs, which will promote considerable economic benefits in the form of lower congestion, greater reliability, and greater access to generation resources. Therefore, we do not believe that the Commission's reforms will discourage cooperation when the potential gains from cooperation are so great.

587. Finally, several petitioners also argue that the Commission must first find an existing rate to be unjust, unreasonable or unduly discriminatory or preferential before it can take the actions regarding cost allocation that it took in Order No. 1000. We disagree that such a finding must be made case-by-case rather than generically. As explained above,[693] the Commission is not required to make individual findings concerning the rates of individual public utility transmission providers when proceeding under FPA section 206 by means of a generic rule.[694] Nor do we agree with FirstEnergy Service Company that Commission actions taken in a rulemaking cannot apply to future jurisdictional transmission service. Commission rulemakings are prospective in their effect, and when the Commission proceeds by rule it can conclude that ''*any* tariff violating the rule would have such adverse effects * * * as to render it 'unjust and unreasonable' '' within the meaning of section 206 of the FPA.[695] The effects that a tariff would have include effects on future jurisdictional transmission service.

588. We further disagree with FirstEnergy Service Company's assertion that where no cost allocation method or methods exist, the Commission cannot use section 206 as a basis for requiring them. The basis for the Commission's reforms in Order No. 1000 is that transmission planning for transmission service and the associated allocation of costs for new transmission facilities are practices that affect rates for purposes of section 206.[696] The Commission also explained that the allocation of transmission costs is often contentious and prone to litigation,[697] and that the lack of *ex ante* cost allocation methods that identify the beneficiaries of proposed regional and interregional transmission facilities may be impairing the ability of public utility transmission providers to implement more efficient or cost-effective transmission solutions identified in the transmission planning process.[698] The absence of a cost allocation method or methods also has an adverse effect on rates by making it difficult to deal with free rider problems related to new facilities. The Commission's authority to require the adoption of a cost allocation method or methods arises directly from its authority under section 206 to ensure that practices that affect transmission rates, such as transmission planning, are just and reasonable and not unduly discriminatory or preferential.

589. FirstEnergy Service Company's argument that section 205 does not permit the Commission to require the filing of rates or contracts is equally flawed. Here, FirstEnergy Service Company is simply arguing that all rates are initially to be proposed by public utility transmission providers. However, the Commission is not requiring the proposal of a particular rate. It is requiring that public utility transmission providers have a cost allocation method or methods in their OATTs to ensure that the costs of new transmission facilities selected in a regional transmission plan for purposes of cost allocation are properly allocated to beneficiaries. It is for public utility transmission providers to propose an actual method or methods. The Commission is simply requiring that any cost allocation method or methods that are proposed meet certain general

[690] *Id.*

[691] Vermont Agencies at 16; Sacramento Municipal Utility District at 14.

[692] Vermont Agencies at 16–17; Sacramento Municipal Utility District at 14.

[693] *See* discussion *supra* at section 0.

[694] *Associated Gas Distributors* v. *FERC,* 824 F.2d at 1008.

[695] *Id.* (emphasis in original).

[696] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 58.

[697] *Id.* P 498.

[698] *Id.* P 499.

principles established in Order No. 1000.

590. The case law cited by FirstEnergy Service Company to support the proposition that the Commission cannot impose a new rate without first determining that an existing rate is unjust, unreasonable, or unduly discriminatory or preferential reinforces our above points. All the cases that FirstEnergy Service Company cites in this connection involve situations in which the court found that the Commission had moved beyond rejecting a proposed rate to the task of redesigning it.[699] The Commission is not here ''imposing'' any rates, as it is not specifying, designing, or redesigning any rates. Instead it is requiring that all public utility transmission providers have a cost allocation method or methods for certain new transmission facilities that comply with a broad set of general principles.

591. We agree with California ISO that rates are not unjust and unreasonable simply because another rate might be more just and reasonable. However, this point applies in a situation where the status quo has been found to be just and reasonable and not unduly discriminatory or preferential, which is not the case here. California ISO argues that in its case such a finding is necessary because it has voluntarily included in its tariff provisions that ensure the construction of needed transmission projects, and it takes into account cost-effectiveness in choosing these transmission projects. This argument misconstrues the Commission's actions here, which are to ensure that certain minimum requirements pertaining to transmission planning and cost allocation are in place. California ISO's practices may already satisfy some of these requirements, in which case it need only explain how it satisfies them in its compliance filing.[700] This, however, does not show that there is no need for such requirements.

592. Ad Hoc Coalition of Southeastern Utilities questions the Commission's ability to require a cost allocation method or methods on the grounds that section 206 limits the Commission's authority over practices affecting rates to those that directly affect rates. Cost allocation is a practice that affects rates because the effect of a cost allocation method or methods is quite direct, as it determines who is responsible for specific costs. As explained above, Order No. 1000 found that the lack of a regional cost allocation method known in advance to transmission planners and the existence of free riders, result in inefficient transmission planning that impedes the development of more efficient and cost effective new transmission facilities, with the result that jurisdictional rates are higher than they would otherwise be. As we have noted previously, we disagree with Ad Hoc Coalition of Southeastern Utilities' contention that requiring utilities to pay for facilities that they do not use does not directly affect rates for jurisdictional transmission service and is therefore beyond the Commission's authority. This argument ignores the reality that any entity connected to the transmission grid may benefit from a transmission facility whether or not it is connected to, or specifically requests service from, a particular transmission facility for which costs have been allocated.[701] Order No. 1000's cost allocation reforms are therefore intended to ensure that all of these beneficiaries are allocated costs roughly commensurate with the benefits they receive in their use of the transmission grid, and we believe that such a requirement can be seen as directly affecting the rates for jurisdictional transmission service.

B. Cost Allocation Method for Regional Transmission Facilities

1. Final Rule

593. In Order No. 1000, the Commission required that each public utility transmission provider have in place a method, or set of methods, for allocating the costs of new transmission facilities selected in the regional transmission plan for purposes of cost allocation.[702] The Commission stated that if the public utility transmission provider is an RTO or ISO, then the cost allocation method or methods must be set forth in the RTO or ISO OATT.[703] In a non-RTO/ISO transmission planning region, the Commission required each public utility transmission provider located within the region to set forth in its OATT the same language regarding the cost allocation method or methods used in its transmission planning region.[704] In either instance, the Commission required that such cost allocation method or methods be consistent with the regional cost allocation principles adopted in Order No. 1000.[705]

594. The Commission did not specify how the costs of an individual regional transmission facility should be allocated.[706] It noted, however, that while each transmission planning region may develop a method or methods for different types of transmission projects, each such method or methods should apply to all transmission facilities of the type in question and would have to be determined in advance for each type of facility.[707] Additionally, the Commission acknowledged that cost containment is important, but declined to establish a corresponding cost allocation principle, primarily because cost containment concerns the level of costs, not how costs should be allocated among beneficiaries.[708]

595. With respect to cost allocation for a proposed transmission facility located entirely within one public utility transmission owner's service territory, the Commission found that a public utility transmission owner may not unilaterally apply the regional cost allocation method or methods developed pursuant to Order No. 1000.[709] However, the Commission also found that a proposed transmission facility located entirely within a public utility transmission owner's service territory could be determined by the public utility transmission providers in the region to provide benefits to others in the region and thus be selected in the regional transmission plan for purposes of cost allocation; then the cost of that transmission facility would be allocated according to that region's regional cost allocation method or methods.[710]

596. In Order No. 1000, the Commission also declined to make new findings with respect to pancaked rates, stating that it was beyond the scope of the proceeding.[711] The Commission further stated that it was not making any modifications to the Commission's pancaked rate provisions for an RTO under Order No. 2000.[712] However, the Commission noted that if rate pancaking was an issue in a particular transmission planning region, stakeholders could raise their concerns in the consultations leading to the compliance proceedings for Order No. 1000 or make a separate filing with the Commission under section 205 or 206 of the FPA, as appropriate.[713]

[699] *See, e.g., Western Resources, Inc.* v. *FERC,* 9 F.3d 1568, 1578–79 (D.C. Cir. 1993).

[700] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at PP 565, 583.

[701] *Id.* P 625.

[702] *Id.* P 558.

[703] *Id.*

[704] *Id.*

[705] *Id.*

[706] *Id.* P 560.

[707] *Id.*

[708] *Id.* P 704.

[709] *Id.* P 564.

[710] *Id.*

[711] *Id.* P 764.

[712] *Id.*

[713] *Id.*

2. Requests for Rehearing and Clarification

597. North Carolina Agencies argue that the Commission's planning and cost allocation reforms represent major changes that have the potential to preempt state authority over bundled retail rates. They state that to date, the Commission has declined to exercise its authority over the transmission component of bundled retail rates and service despite pressure to do so and the U.S. Supreme Court's decision in *New York* v. *FERC*.[714] North Carolina Agencies assert that the Commission must recognize that the applicability of any cost allocation methods that result from Order No. 1000 is limited to unbundled transmission and cannot impinge on state jurisdiction with respect to bundled retail rates. Ad Hoc Coalition of Southeastern Utilities likewise contends that the allocation of the cost of regional transmission facilities to entities performing a retail sales function would preempt state commissions in setting bundled retail rates because under the Supremacy Clause, utilities will be entitled to recover their costs in retail rates.

598. Northern Tier Transmission Group also states that the Commission should clarify that it does not intend to set retail rates. It states that the Commission has not explained the relationship between the mandatory cost allocation process and the ability of a project proponent to recover the costs of a selected transmission facility.

599. In a related argument, Alabama PSC argues that Order No. 1000 fails to satisfy the requirements of the Administrative Procedure Act (APA)[715] because it lacks definiteness on how cost allocation will translate into recovery. It is concerned that the rule will result in stranded costs if a transmission provider cannot recover allocated costs because of the absence of an appropriate contractual vehicle and lead to cost shifting to others within the region. Alabama PSC also asserts that Commission is being inconsistent when it does not address cost recovery but then does not accept participant funding, which Alabama PSC describes as a form of cost recovery, as a regional cost allocation method. Southern Companies argue that if there is no payment obligation coinciding with a cost assignment, industry cannot presume that Order No. 1000's objective is to create a rate structure to induce transmission developers to participate more fully in regional transmission planning processes. They state that the Commission should address this issue in order to prevent parties from engaging in a futile exercise over the next eighteen months.

600. Several other petitioners also take issue with the Commission's determination to not address cost recovery issues in Order No. 1000. Sacramento Municipal Utility District argues that the issue with respect to cost recovery mechanisms is not the identity of the transmission provider, but whether the party being assessed charges is one of the provider's customers. It maintains that ''it is not a mere concern over form'' to expect an explanation of the mechanism for recovering a rate when the party being charged is not a customer.

601. Edison Electric Institute, NV Energy and Southern Companies argue that the Commission does not explain how costs can be allocated under a regional transmission plan in a non-RTO/ISO region without a contractual mechanism permitting the charging and collection of such costs. Edison Electric Institute acknowledges that a tariff could provide a contractual mechanism for the collection of allocated costs, but states that Order No. 1000 does not identify any mechanism for requiring the payment of costs in the absence of such an applicable tariff or agreement. Edison Electric Institute thus asserts that the Commission is not engaging in reasoned decision making when it concludes that it ''would permit recovery of costs from a beneficiary in the absence of a voluntary arrangement.''[716]

602. In the alternative, Edison Electric Institute argues that the Commission should clarify: (1) Whether allocation in a regional plan of costs to a beneficiary in a non-RTO/ISO region without a voluntary arrangement to pay creates an obligation of the beneficiary to pay those costs; and (2) if so, the mechanism for collecting such costs, including the source of the obligation of the beneficiary to pay. Southern Companies make a similar argument.

603. National Rural Electric Coops argue that the distinction between cost allocation and cost recovery in Order No. 1000 has no practical significance. NARUC argues that if cost allocation is distinct from cost recovery, it is not clear that the Commission's authority to set rates for transmission under the FPA provides the Commission with jurisdiction over cost allocation.

604. Northern Tier Transmission Group requests that the Commission clarify the relationship between cost allocation and cost recovery. It states that the ability to recover costs appears to be merely a factor that can be considered and acknowledged in the cost allocation process. Northern Tier Transmission Group asserts that this issue is material to the decision to participate in the construction of a project. Therefore a clarification of the intended relationship between cost allocation and cost recovery will better inform the methods developed for and the analysis performed by the regional and interregional transmission planning processes.

605. Northern Tier Transmission Group also asserts that the Commission has no authority under the FPA to require the imposition of transmission construction costs on non-jurisdictional beneficiaries or to impose cost recovery on the United States or any state including any political subdivision.[717] Edison Electric Institute states that paragraph 629 of Order No. 1000 states that non-jurisdictional transmission providers that do not participate in the regional planning process are not responsible for costs allocated in that process. It states that it is arbitrary and capricious to treat jurisdictional transmission providers and non-public utility transmission providers differently with respect to any obligation they may have, in the absence of a voluntary agreement, to pay costs allocated to them in a regional planning process.

606. Arizona Cooperative and Southwest Transmission argue that paragraph 629 in Order No. 1000 suggests that a non-public utility will be forced to accept the regional cost allocation, and may effectively forfeit its right to avoid an unduly discriminatory cost assignment if participating in the process means that it loses the ability to exercise its right to seek relief from the Commission. Arizona Cooperative and Southwest Transmission argue that non-participation is not a desirable answer to this problem, especially as an entity that does not participate could still get saddled with costs and would also forego the opportunity to have its own contributions to a more robust grid included in the regional plan.

607. Alabama PSC argues that if the regional planning process supersedes or replaces the output of a state integrated

[714] North Carolina Agencies at 4 (citing 535 U.S. 1 (2002)). North Carolina Agencies state that while *New York* v. *FERC* includes *dicta* suggesting that the Commission's authority is an open issue, the Court found that the jurisdictional issue is a difficult one. North Carolina Agencies at 5.

[715] Administrative Procedure Act, 5 U.S.C. 706(2)(A).

[716] Edison Electric Institute at 7–8.

[717] Northern Tier Transmission Group at 6 (citing 16 U.S.C. 824(e) and (f); *Bonneville Power Admin.* v. *FERC*, 422 F.3d 908 (9th Cir. 2005)).

resource plan that relies on participant funding, it will infringe on a state's prerogative to manage the costs borne by its consumers. Alabama PSC also states that Order No. 1000 incorrectly asserts that the cost allocation requirements conform fully with the position taken by the Alabama PSC. Instead, it states that its concern is that a regional process may identify electricity consumers in Alabama as receiving benefits from a new transmission project selected in a regional transmission plan for purposes of cost allocation, even if the supposed benefits are completely at odds with Alabama PSC's conclusions. Thus, even though Order No. 1000 states that consumers will not be assigned costs from which they derive no benefit, Alabama PSC remains concerned about this and maintains that states should have the option of vetoing such a course or opting out of any cost allocation.

608. Florida PSC argues that the cost allocation provisions of Order No. 1000 infringe on its jurisdiction. Florida PSC states that Florida utilities are vertically-integrated, and no part of the state is a member of an RTO or ISO. It thus retains authority over cost allocation. Florida PSC asserts that planning decisions under the new processes will affect wholesale rates that will flow to retail customers. Florida PSC thus argues that regions may find themselves paying higher retail rates for benefits realized only in a neighboring region. Florida PSC argues that the Commission does not have authority to assign cost recovery to retail rates for benefits not defined as such in the retail customers' region.

609. Transmission Access Policy Study Group argues that Order No. 1000 erred in finding that comments on access to regionally cost allocated facilities through regional tariffs at non-pancaked rates were beyond the scope of the proceeding.[718] It asserts that failing to address these issues leaves a void that must be filled before regional cost allocations can be implemented in non-RTO regions.[719] It believes that a regional tariff, with non-pancaked rates covering both existing and new facilities, is the best way to address these issues because such tariffs can solve cost allocation implementation issues and avoid the creation of new rate pancakes. Transmission Access Policy Study Group suggests that if the Commission does not grant rehearing, it should use its authority to induce transmission providers to adopt regional rates that eliminate pancaking and foster transmission investment.

610. Alternatively, Transmission Access Policy Study Group states that the Commission should require a process to address access issues at the compliance stage. It also argues that access should be addressed when a specific cost allocation is applied to a project. Transmission Access Policy Study Group states that in non-RTO regions, the Commission should require that access issues be addressed in the regional process for selection of an upgrade and the application of the regional cost allocation to a facility, as well as require filing of the specific cost allocation as applied to the particular project selected for regional cost allocation, with a description of how access will be provided and on what rates, terms, and conditions. Transmission Access Policy Study Group believes that specific applications of the regional cost allocation should be filed as soon as the constructor of the facility is identified, with access issues addressed at that time rather than when the facility is completed.[720] According to Transmission Access Policy Study Group, this will help address uncertainty caused by the absence of regional tariffs and Order No. 1000's preference for flexibility. Finally, Transmission Access Policy Study Group urges prompt public disclosure of the mechanism to provide access to regionally cost-allocated facilities, and it states that it is essential to address access issues before a proposed facility proceeds through the permitting and siting process.

611. Several petitioners question the Commission's decision not to address cost containment issues in Order No. 1000. For example, Illinois Commerce Commission argues that the Commission does not provide a good reason for not addressing cost containment, and that it must be addressed to prevent excessive costs, which is a fundamental part of any appropriate cost allocation method. Illinois Commerce Commission asserts that even if Order No. 1000 is not the appropriate forum, the Commission erred in failing to identify an alternative forum.

612. Wisconsin PSC requests that there be a mandate to consider cost overrun containment mechanisms. It argues that uncontained costs are as likely to undermine needed transmission development as a flawed cost allocation method or no method at all would. Wisconsin PSC states that Order No. 1000's distinction between the allocation of costs and the amount of costs is a hollow one because the key question for states and the customers who pay for the lines is the cost/benefit of the buildout.[721] It also argues that since the Commission saw fit to develop a fallback mechanism for situations where a project developer abandons a line that a transmission provider had depended upon for reliability and supply purposes; it should also have a fallback mechanism for cost overruns, which pose a much greater prospect of harm to the consuming public.

3. Commission Determination

613. We affirm Order No. 1000's requirement that each public utility transmission provider have in place a method, or set of methods, for allocating the costs of new transmission facilities selected in the regional transmission plan for purposes of cost allocation.[722] In Order No. 1000, the Commission did not specify how the costs of an individual regional transmission facility should be allocated.[723] It noted, however, that while each transmission planning region may develop a method or methods for different types of transmission projects, each such method or methods should apply to all transmission facilities of the type in question and would have to be determined in advance for each type of facility.[724] We continue to believe that such an approach is necessary to ensure that the rates, terms, and conditions of jurisdictional service are just and reasonable and not unduly discriminatory or preferential. This is because in the absence of clear cost allocation rules, there is a greater potential that pubic utility transmission providers and nonincumbent transmission developers may be unable to develop transmission facilities that are determined by the region to meet their needs.[725]

614. In response to Alabama PSC's argument that a state should be permitted to veto any particular cost allocation if it disagrees with the outcome, we reiterate Order No. 1000's finding declining to mandate veto rights

[718] Transmission Access Policy Study Group at 40 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at PP 549, 764).

[719] Transmission Access Policy Study Group asserts that Order No. 1000's focus on cost allocation as disassociated from service relationships heighten these concerns.

[720] Transmission Access Policy Study Group notes that Order No. 1000 does not address timing of the filing of specific applications of the regional cost allocation.

[721] Wisconsin PSC at 10–11 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at PP 704–05 (2007)).

[722] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 558.

[723] *Id.* P 560.

[724] *Id.*

[725] *Id.* P 559.

for state committees. However, as stated in Order No. 1000, the Commission does not preclude public utility transmission providers from proposing such mechanisms on compliance if they choose to do so.[726] We emphasize that any such mechanisms must be consistent with the goals of Order No. 1000's transmission planning and cost allocation reforms, an important part of which are to provide that costs are allocated to beneficiaries roughly commensurate with the benefits that they receive.

615. In response to Alabama PSC's concern that the Commission's cost allocation reforms could lead to stranded transmission costs due to the absence of a necessary contractual vehicle, we note that entities that receive benefits are subject to a Commission-approved transmission tariff. The existence of obligation arising under such a tariff is sufficient to ensure that there will be no stranded costs, and the question of specific recovery mechanisms is beyond the scope of this proceeding. This point applies equally to Southern Companies' concern about payment obligations that correspond to cost assignments.

616. Additionally, we find no merit in the arguments advanced to challenge our position in Order No. 1000 that cost allocation and cost recovery are distinct issues and our determination not to address matters of cost recovery there.[727] We therefore affirm the Commission's decision in Order No. 1000 that cost recovery is a separate issue, and we will not specify how costs can be recovered for transmission projects that are selected in the regional transmission plan for purposes of cost allocation. The U.S. Supreme Court has found that the Commission has broad discretion in determining which issues to address in a particular proceeding.[728] While we will not address cost recovery in this proceeding, we note that cost recovery may be considered as part of a region's stakeholder process in developing a cost allocation method or methods to comply with Order No. 1000. Therefore, to the extent that cost recovery provisions are considered in connection with a cost allocation method or methods for a regional or interregional transmission facility, public utility transmission providers may include cost recovery provisions in their compliance filings.

617. We thus reject Sacramento Municipal Utility District's contention that Order No. 1000 is deficient because it does not explain the mechanism for recovering a cost ''when the party being charged is not a customer.'' [729] Sacramento Municipal Utility District's claim of deficiency is premised on the proposition that costs cannot be allocated in a situation where an entity does not have a preexisting contractual relationship with the entity that will recover the costs. It considers a cost allocation in this situation to be a cost allocation to a non-customer. We have addressed this issue at length above. Because we disagree with Sacramento Municipal Utility District's premise, we disagree that our decision not to address cost recovery in Order No. 1000 makes the order deficient. This conclusion applies equally to Sacramento Municipal Utility District's assertion that it is not a mere concern over form to expect an explanation of the mechanism for recovering a charge when the party being charged is not a customer.

618. Edison Electric Institute seeks clarification on how costs can be recovered from a beneficiary in the absence of an applicable tariff or agreement. Edison Electric Institute's request is based on its reading of paragraph 506 of Order No. 1000, which it notes states that the Commission ''would permit recovery of costs from a beneficiary in the absence of a voluntary arrangement.'' However, this statement is simply part of a summary of the Commission's ruling in *AEP.* This summary does not imply that Order No. 1000 contemplates the recovery of costs from a beneficiary in the absence of an applicable tariff or agreement. All tariffs will be required to contain an appropriate cost allocation method or methods.

619. In response to Alabama PSC, the Commission was not being inconsistent on the issue of cost recovery when it found that participant funding, which it describes as a form of cost recovery, cannot be a regional cost allocation method. This argument assumes that cost allocation and cost recovery are not distinct issues. The Commission's position is that they are distinct—a point that Alabama PSC does not challenge—and thus when it concluded that participant funding cannot serve as a regional cost allocation method, the Commission was not making a conclusion regarding cost recovery mechanisms. As a result, the Commission was not taking an action that was inconsistent with its position that it would not address cost recovery in Order No. 1000. We address the prohibition against participant funding as a regional cost allocation method elsewhere in this order. Similarly, we disagree with Northern Tier Transmission Group that the Commission is impermissibly imposing recovery of transmission construction costs on non-jurisdictional entities, as Order No. 1000 did not address matters of cost recovery.

620. Moreover, we disagree with petitioners' arguments that Order No. 1000's cost allocation provisions infringe on state authority over the siting and permitting of transmission facilities, or that they infringe on integrated resource planning. Petitioners have not demonstrated anything persuasive to support their comments. More generally, as we discuss in the cost allocation legal authority section above, we have ample authority under the FPA to require public utility transmission providers to file regional and interregional cost allocation methods, and we direct petitioners to that section for a fuller discussion of the Commission's legal authority.

621. We disagree with those petitioners who claim the Commission is seeking to regulate bundled retail rates. North Carolina Agencies provide no clear explanation for their position. Indeed, they state only that there is a potential for the Commission to regulate bundled retail rates. As for Ad Hoc Coalition of Southeastern Utilities' arguments, we disagree that requiring the implementation of a method to allocate the costs of new transmission facilities selected in a regional transmission plan for purposes of cost allocation amounts to regulation of bundled retail rates.[730] As discussed in Order No. 1000 and in this order, we have ample legal authority to adopt the Order No. 1000 cost allocation reforms.[731] We also affirm Order No. 1000's discussion of this issue, namely, that:

> [I]t is not clear why cost allocations consistent with this Final Rule would affect state jurisdiction differently from existing cost allocations. In any event, we find that such arguments are premature. It is inappropriate for the Commission to decide such issues generically in a rulemaking, as such issues should be decided based on

[726] *Id.* P 502.

[727] *Id.* P 563.

[728] *Mobil Oil Exploration & Producing Southeast, Inc.* v. *United Distribution Companies,* 498 U.S. 211, 230 (1991). *See also Tennessee Valley Municipal Gas Association* v. *FERC,* 140 F.3d. 1085, 1088 (D.C. Cir. 1998).

[729] Sacramento Municipal Utility District at 11.

[730] Ad Hoc Coalition of Southeastern Utilities at 74.

[731] *See, e.g.,* Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 530–49; *see also* discussion *supra* at section 0 and discussion *supra* at section IV.A.3.

specific facts and circumstances, none of which are presented here.[732]

Accordingly, we reiterate here that in this generic rulemaking proceeding, these issues are not presented for Commission determination.

622. To the extent a non-public utility transmission provider exercises its discretion to enroll as a transmission provider in a regional transmission planning process, it may be allocated costs roughly commensurate with the benefits that it is determined to receive from new transmission facilities selected in the regional transmission plan for purposes of cost allocation.[733] We disagree with Arizona Cooperative and Southwest Transmission that a non-public utility transmission provider will effectively forfeit its rights to avoid undue discrimination by participating in the regional transmission planning process for several reasons. First, the choice of whether to enroll in the regional transmission planning process, and thus be subject to being determined to be a beneficiary for which cost allocation is appropriate, remains with each non-public utility transmission provider. Second, it will have a voice in the process of determining the cost allocation method, and if it believes that the result is unduly discriminatory, it maintains the right to intervene in the compliance proceeding when that method is filed at the Commission. Third, for future applications of the method to actual new facilities, a non-public utility transmission provider could exercise any right it has in the regional transmission planning process to withdraw rather than accept the allocation of costs.[734] And finally, non-public utility transmission providers choosing to remain in the transmission planning region notwithstanding dissatisfaction with a particular application of the cost allocation method may file with the Commission for a FPA 206 determination that the approved method is no longer just and reasonable or is unduly discriminatory or preferential in practice.

623. We affirm the Commission's finding in Order No. 1000 that this is not the proper proceeding to address rate pancaking issues. If rate pancaking is an issue in a particular transmission planning region, stakeholders may raise their concerns in the consultations leading to the compliance proceedings for Order No. 1000 or make a separate filing with the Commission under section 205 or 206 of the FPA, as appropriate.[735] The Commission has the discretion to determine which issues to address in a particular proceeding.[736]

624. With regard to concerns related to access to new transmission facilities for which an entity has been allocated costs pursuant to a regional or interregional cost allocation method, the Commission believes that the appropriate forum to consider such issues in the first instance is in the regional transmission planning process for each transmission planning region. Each regional transmission planning process must provide entities who will receive regional or interregional cost allocation an understanding of the identified benefits on which the cost allocation is based. The Commission anticipates that regions may approach these issues in different ways and thus will allow public utility transmission providers, in consultation with stakeholders, to address these issues as they develop the regional and interregional cost allocation methods for their transmission planning region. We note that entities may utilize the existing OATT provisions regarding Order No. 890 dispute resolution, which will also apply to the new transmission planning and cost allocation processes adopted under Order No. 1000, if they disagree with the public utility transmission provider's identification of benefits and beneficiaries for a regional or interregional transmission facility selected in the regional transmission plan for purposes of cost allocation.

625. We affirm the Commission's decision in Order No. 1000 that cost containment issues relate to the level of costs and not how costs should be allocated among beneficiaries.[737] As the Commission emphasized in Order No. 1000, this proceeding relates to transmission planning reforms, including the role of cost allocation in transmission planning, not the level of transmission costs,[738] and therefore this proceeding is not the appropriate forum for addressing the transmission cost containment issues raised by petitioners. However, as with cost recovery, we note that cost containment may be considered as part of a region's stakeholder process in developing a cost allocation method or methods to comply with Order No. 1000. Therefore, to the extent that cost containment provisions are considered in connection with a cost allocation method or methods for a regional or interregional transmission facility, public utility transmission providers may include transmission cost containment provisions in their compliance filings.

C. Cost Allocation Method for Interregional Transmission Facilities

1. Final Rule

626. In Order No. 1000, the Commission required each public utility transmission provider in a transmission planning region to have, together with the public utility transmission providers in its own transmission planning region and a neighboring transmission planning region, a common method or methods for allocating the costs of a new interregional transmission facility among the beneficiaries of that transmission facility in the two neighboring transmission planning regions in which the transmission facility is located. The Commission explained that the cost allocation method or methods used by the pair of neighboring transmission regions can differ from the cost allocation method or methods used by each region to allocate the cost of a new interregional transmission facility within that region.[739] The Commission stated that in an RTO or ISO region, the method must be filed in the OATT.[740] Additionally, the Commission stated that in a non-RTO/ISO transmission planning region, the same common cost allocation method or methods must be filed in the OATT of each public utility transmission provider in the transmission planning region.[741] In either instance, the Commission stated that such cost allocation method or methods must be consistent with the interregional cost allocation principles adopted in Order No. 1000.[742]

627. The Commission also clarified that it would not require each transmission planning region to have the same interregional cost allocation method or methods with each of its neighbors.[743] Order No. 1000 provided that each pair of transmission planning

[732] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 548.

[733] *See* discussion *supra* at PP 0–0.

[734] To accommodate the participation of non-public utility transmission providers, the relevant tariffs or agreements governing the regional transmission planning process could establish the terms and conditions of orderly withdrawal for non-public utility transmission providers that are unable to accept the allocation of costs pursuant to a regional or interregional cost allocation method. *See* Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 820.

[735] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 764.

[736] *Mobil Oil Exploration & Producing Southeast, Inc.* v. *United Distribution Companies,* 498 U.S. 211, 230 (1991). *See also Tennessee Valley Municipal Gas Association* v. *FERC,* 140 F.3d. 1085, 1088 (D.C. Cir. 1998).

[737] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 704.

[738] *Id.*

[739] *Id.* P 578.

[740] *Id.*

[741] *Id.*

[742] *Id.*

[743] *Id.* P 580.

regions may develop its own approach to interregional cost allocation that satisfies both transmission planning regions' needs and concerns, as long as that approach satisfies the interregional cost allocation principles.[744]

628. The Commission did not specify how the costs for an individual interregional transmission facility should be allocated.[745] However, the Commission stated that while transmission planning regions can develop a different cost allocation method or methods for different types of transmission projects, such a cost allocation method or methods should apply to all transmission facilities of the type in question and each cost allocation method would have to be determined in advance for each type of transmission facility.[746] Also, the Commission adopted the requirement that an interregional transmission facility must be selected in a relevant regional transmission plan for purposes of cost allocation to be eligible for interregional cost allocation pursuant to the interregional cost allocation method or methods.[747]

629. The Commission also noted that as it made clear in its discussion of Cost Allocation Principle 4,[748] costs may be assigned only on a voluntary basis to a transmission planning region in which an interregional transmission facility is not located.[749] The Commission noted that, given this option, regions are free to negotiate interregional transmission arrangements that allow for the allocation of costs to beneficiaries that are not located in the same transmission planning region as any given interregional transmission facility.[750]

630. In addition, the Commission clarified that the requirement to coordinate with neighboring regions applies to public utility transmission providers within a region as a group, not to each individual public utility transmission provider acting on its own. For example, within an RTO or ISO, the RTO or ISO would develop an interregional cost allocation method or methods with its neighboring regions on behalf of its public utility transmission owning members.[751]

[744] *Id.*

[745] *Id.* P 581.

[746] *Id.*

[747] *Id.*

[748] *See* Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at section IV.E.5.

[749] *Id.* P 582.

[750] *Id.*

[751] *Id.* P 584.

2. Requests for Rehearing or Clarification

631. Several petitioners seek clarification of the Commission's interregional cost allocation requirements. California ISO seeks clarification that one planning region cannot allocate costs to a neighboring transmission planning region for a transmission line that interconnects to the system of the neighboring region but that the neighboring region has not determined is needed and has not included in its transmission plan.

632. MISO Transmission Owners Group 1 requests clarification that Order No. 1000's statement that a transmission owner in an RTO or ISO can comply with the proposed interregional cost allocation mandates through participation in the RTO and ISO is not intended to alter a transmission owner's section 205 rights or the division of section 205 filing rights between an RTO and its transmission owners. It states that if the Commission does not provide this clarification, the Commission must grant rehearing because limiting the section 205 filing rights of transmission owners would be contrary to judicial precedent.[752]

633. Transmission Dependent Utility Systems request clarification that transmission customer load-serving entities should be able to review and comment on the development of interregional cost allocation methods and have their input considered and addressed before public utility transmission providers make their compliance filings. Transmission Dependent Utility Systems assert this is necessary to ensure consistency with the non-discrimination requirements of FPA section 205.

3. Commission Determination

634. As stated in Order No. 1000, the Commission requires that each public utility transmission provider in a transmission planning region must have, together with the public utility transmission providers in its own transmission planning region and a neighboring transmission planning region, a common method or methods for allocating the costs of a new interregional transmission facility among the beneficiaries of that transmission facility in the two neighboring transmission planning regions in which the transmission facility is located.[753] We continue to believe that the absence of clear cost allocation rules for interregional transmission facilities can impede the development of such transmission facilities due to the uncertainty regarding the allocation of responsibility for associated costs, potentially adversely affecting rates for jurisdictional services causing them to become unjust and unreasonable or unduly discriminatory or preferential.[754]

[752] MISO Transmission Owners Group 1 at 13–14 (citing *Atlantic City Electric Co.* v. *FERC,* 295 F.3d 1 (D.C. Cir. 2002)).

[753] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 579.

635. In response to California ISO's request that we clarify that another region could not impose costs on it for an interregional transmission facility without approval, Order No. 1000 states that, for an interregional transmission facility to receive interregional cost allocation, each of the neighboring transmission planning regions in which the interregional transmission facility is proposed to be located must select the facility in its regional transmission plan for purposes of cost allocation.[755] As such, we believe that it is clear that, if one of the regional transmission planning processes does not select the interregional transmission facility to receive interregional cost allocation, neither the transmission developer nor the other transmission planning region may allocate the costs of that interregional transmission facility under the provisions of Order No. 1000 to the region that did not select the interregional transmission facility.

636. In response to MISO Transmission Owners Group 1, we clarify that the Order No. 1000 interregional cost allocation requirements are not intended to alter the section 205 rights of transmission owners and RTOs.

637. In response to Transmission Dependent Utility Systems, we clarify that all interested parties, including transmission customer load-serving entities, must have the opportunity to participate in the process of developing the interregional cost allocation method or methods. As the Commission stated in Order No. 1000, in developing appropriate cost allocation methods for their regional and interregional transmission facilities, public utility transmission providers must consult with stakeholders.[756] The Commission also stated that stakeholder input in the development of a cost allocation method or methods should ensure that the method or methods ultimately agreed upon is balanced and does not favor any

[754] *Id.*

[755] *Id.* P 436.

[756] *Id.* P 482.

particular entity.[757] Consistent with Order No. 890, the Commission defined ''stakeholder'' in Order No. 1000 as including any party interested in the regional transmission planning process.[758] As such, we view stakeholder participation, including that by load-serving entities, as an important aspect of the development of compliance filings to meet the requirements of Order No. 1000.

D. Principles for Regional and Interregional Cost Allocation

1. Use of a Principles-Based Approach

638. In Order No. 1000, the Commission required each public utility transmission provider to show on compliance that its cost allocation method or methods for regional cost allocation and its method or methods for interregional cost allocation are just and reasonable and not unduly discriminatory or preferential by demonstrating that each method satisfies the six cost allocation principles.[759] The Commission took a principles-based approach because it recognized that regional differences may warrant distinctions in cost allocation methods among transmission planning regions. The Commission explained that the six regional cost allocation principles apply to, and only to, a cost allocation method or methods for new regional transmission facilities selected in a regional transmission plan for purposes of cost allocation.[760] Likewise, the Commission stated that the six analogous interregional cost allocation principles apply to, and only to, a cost allocation method or methods for a new transmission facility that is located in two neighboring transmission planning regions and accounted for in the interregional transmission coordination procedure in an OATT.[761] Additionally, the Commission stated that the cost allocation principles do not apply to other new transmission facilities and therefore did not foreclose the opportunity for a developer or individual customer to voluntarily assume the costs of a new transmission facility.[762]

639. The Commission declined to adopt a default regional or interregional cost allocation method, but stated that in the event of a failure to reach an agreement on a cost allocation method or methods, it would use the record in the relevant compliance filing proceeding as a basis to develop a cost allocation method or methods that meets its proposed requirements.[763]

a. Arguments That Principles-Based Cost Allocation Methods Are Unfair and Arguments Related to Commission Determination of Cost Allocation Method Pursuant to the Compliance Process

640. Illinois Commerce Commission argues that Order No. 1000 appears to require transmission providers to be responsible for estimating project benefits, which effectively delegates the Commission's authority over rates and to define what constitutes benefits. It maintains that delegating this authority to the transmission provider and the stakeholder process does not ensure that planning criteria and cost allocation methods based on benefits will be just and reasonable.

641. Illinois Commerce Commission asserts that the stakeholder process may neglect the interests of some load-serving entities that will bear the costs of transmission investment when the interests of those load-serving entities are not aligned or directly conflicts with the majority of load-serving entities and other stakeholders within the region. It cites *Illinois Commerce Commission* as an example of an outcome where the majority of stakeholders agreed to spread costs in eastern PJM to utilities in western PJM, and the Commission deferred to this ''regional consensus'' while acknowledging there was none. Illinois Commerce Commission states that the Seventh Circuit disagreed and found that one group of utilities' desire to be subsidized by another is no reason in itself for giving them their way.

642. Illinois Commerce Commission further argues that delegating the Commission's obligation to ensure just and reasonable rates to a stakeholder process violates section 205 due process rights of interested parties because it imposes an undue burden on parties to participate in a new and costly process without providing the funding to participate. It contends that the process will lack a public administrative record, making it difficult for interested parties who would have otherwise intervened in a normal administrative process to follow the proceeding. Illinois Commerce Commission states that the right of parties to bring a section 206 complaint is an inadequate remedy in light of these issues.

643. Several petitioners seek rehearing of the Commission's statement that if an agreement on a cost allocation method is not reached, it will use the record to develop a method or methods for the region, arguing that the Commission does not have the authority to do so.[764] Florida PSC argues that this provision encroaches on Florida's jurisdiction because the Commission does not have authority to assign cost recovery to retail customers.[765] Kentucky PSC also argues that the due process requirements of the state integrated resource planning and certificate of public convenience and necessity processes is being replaced by majoritarian processes backed by the threat that the Commission will determine cost allocation processes if the regional group cannot.

644. Illinois Commerce Commission argues that Order No. 1000 implies that if there is consensus, the Commission will accept that compliance filing. Illinois Commerce Commission seeks rehearing of the meaning of ''consensus'' if it means here something different from ''agreement.'' [766] It argues that the term is insufficient to protect those who may be harmed by a majority. Additionally, Illinois Commerce Commission argues that requiring a consensus means that minority interests will always lose, which is unduly discriminatory on its face, and forcing minority interests to bring a section 206 complaint is insufficient to protect their interests and overly burdensome.

645. New York Transmission Owners seek clarification that the Commission will impose a cost allocation method on transmission planning regions only as a last resort after consensus has been encouraged through mediation and other alternative dispute resolution procedures.

646. Transmission Dependent Utility Systems seek clarification, or in the alternative rehearing, that compliance filings must document the opportunities for customer input in the development of regional and interregional cost allocation methods as well as the basis relied upon for disregarding any such input. They argue that this information is necessary to gauge the inclusiveness and transparency of the processes for developing cost allocation methods.

i. Commission Determination

647. We affirm the Commission's decision that the appropriate approach is for public utility transmission providers to develop regional and interregional cost allocation methods based on the six cost allocation

[757] *Id.* P 671.
[758] *Id.* P 143.
[759] *Id.* P 603.
[760] *Id.*
[761] *Id.*
[762] *Id.*
[763] *Id.* PP 607, 610.
[764] *See, e.g.,* Georgia PSC; Illinois Commerce Commission; and Florida PSC.
[765] Florida PSC at 7 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 607).
[766] Illinois Commerce Commission at 35.

principles described in Order No. 1000, thereby allowing public utility transmission providers the flexibility to develop cost allocation methods that best suit regional needs. The Commission disagrees that Order No. 1000 is delegating the Commission's authority over rates to define what constitutes benefits. The proper context for further consideration of ''benefits'' and ''beneficiaries'' is in the Commission's review of compliance proposals and a record before the Commission.[767] As the Commission explained in Order No. 1000, the cost allocation principles do not prescribe a uniform approach, but provide the public utility transmission providers in consultation with the stakeholders in each region the opportunity to first develop their own method or methods, and recognized that regional differences may warrant distinctions in cost allocation methods.[768] It would be inconsistent with the regional flexibility provided in Order No. 1000 for the Commission to prescribe a uniform approach to determining benefits or beneficiaries when a multitude of factors vary across transmission planning regions and the entire country.

648. In response to concerns that a stakeholder process is an inappropriate way to allocate costs, we note that the Commission has previously found, and the D.C. Circuit has affirmed, that a stakeholder process is appropriate when unresolved issues may be better addressed in a forum featuring broad stakeholder input, and where a transmission solution can be better tailored to meet regional transmission needs through broad input from interested participants that may not otherwise participate in a Commission proceeding.[769] The public utility transmission providers and stakeholders that make up the region are intimately familiar with the transmission needs of their region. Therefore, they are in the best position to develop, and submit to the Commission for review, a cost allocation method or methods that complies with the six cost allocation principles and best meets the transmission planning region's needs. This does not amount to a delegation of Commission authority because the Commission ultimately will determine whether the method or methods are just and reasonable and interested parties will continue to have an opportunity to support or oppose the cost allocation methods proposed in the compliance filings at the Commission.[770]

649. It also does not interfere with section 205 rights or otherwise impose an undue burden on parties to participate in new and costly processes. The transmission planning and cost allocation processes in Order No. 1000 are not entirely new, but rather build on the reforms to the processes already required by Order No. 890, in which all interested parties should already be participating. In any event, with regard to state regulators, such as Illinois Commerce Commission, we have already explained above that, consistent with Order Nos. 1000 and 890, they may request that the public utility transmission providers in their region propose a mechanism in their compliance filings providing for state regulators to recoup the costs of their participation in the regional transmission planning process.[771] In addition, interested parties retained their section 206 rights to file a complaint if they have concerns about the process or the method or methods proposed. Illinois Commerce Commission has not provided a reason that section 206 would not be an appropriate remedy and not identified specific facts to illustrate a scenario where it would not be able to obtain an adequate remedy under section 206.

650. We also affirm the Commission's decision in Order No. 1000 that, in the event of a failure to reach an agreement on a cost allocation method or methods, the Commission will use the record in the relevant compliance filing proceeding as a basis to develop a cost allocation method or methods that meets Order No. 1000's cost allocation principles.[772] This provision does not infringe upon state jurisdiction, as suggested by the Florida and Kentucky PSCs, because, as discussed above, states retain whatever jurisdiction they have over retail rates.

651. In response to Illinois Commerce Commission's argument regarding whether a ''consensus'' of stakeholders is synonymous with ''agreement,'' and if so, that such an approach would allow the majority to override minority interests when making compliance filings, we reiterate our finding in Order No. 1000 that ''the Commission will consider in response to compliance filings all issues raised by commenters, such as what constitutes an impasse, [and] whether there should be deference to the majority * * *.'' [773] Accordingly, we decline to speculate in advance of these compliance filings the extent to which the Commission would give weight to the majority of public utility transmission providers and stakeholders in a region.

652. In response to New York Transmission Owners, we reiterate that the Commission will use the record in the relevant compliance filings as a basis to develop a cost allocation method or methods for a transmission planning region when the transmission planning region fails to reach an agreement. To this end, we note that in response to a directive to do so in Order No. 1000,[774] the Commission's staff has been made available to assist public utility transmission providers and stakeholders in the various regions around the country in reaching an agreement on a compliance filing. The Commission also noted in Order No. 1000 that the procedural mechanisms used by it in response to compliance filings will depend on the nature of remaining disputes and what issues are still at stake that are preventing the public utility transmission providers in each transmission planning region or pair of transmission planning regions from reaching a consensus.[775] Accordingly, in advance of such compliance filings, we decline to specifically endorse any particular procedural method for resolving cost allocation disputes brought forward in compliance filings; mediation or other alternative dispute resolution procedures, as suggested by New York Transmission Owners are certainly viable methods to encourage consensus and will be considered if necessary at the appropriate time.

653. In response to Transmission Dependent Utility Systems' request that compliance filings must document the opportunities for customer input provided, as well as the basis relied upon for disregarding any such customer input, we do not believe any clarification of Order No. 1000 is necessary. Order No. 1000 already provides that ''[p]ublic utility transmission providers must document in their compliance filings the steps they have taken to reach consensus on a cost allocation method or set of methods to comply with this Final Rule, as thoroughly as practicable, and provide whatever information they view

[767] *Id.* P 624.

[768] *Id.*

[769] *Braintree Elec. Light Dept.* v. *ISO New England, Inc.,* 128 FERC ¶ 61,008 (2009) (citing *MISO,* 125 FERC ¶ 61,038, at P 19 (2008); *Pepco Energy Servs.* v. *PJM Interconnection, L.L.C.,* 124 FERC ¶ 61,008, at P 24 (2008); *PSC of Wis.* v. *FERC,* 545 F.3d 1058, 1063 (D.C. Cir. 2008)).

[770] *PSC of Wis.* v. *FERC,* 545 F.3d at 1064.

[771] *See* discussion *supra* at section 0. (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 162 and quoting Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 574 n.339 and P 586)).

[772] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 607.

[773] *Id.* P 609.

[774] *Id.* P 14.

[775] *Id.* P 609.

as necessary for the Commission to make a determination of the appropriate cost allocation method or methods.'' [776]

2. Cost Allocation Principle 1—Costs Allocated in a Way That Is Roughly Commensurate With Benefits

654. In Order No. 1000, the Commission adopted the following Cost Allocation Principle 1 for both regional and interregional cost allocation:

Regional Cost Allocation Principle 1: The cost of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits. In determining the beneficiaries of transmission facilities, a regional transmission planning process may consider benefits including, but not limited to, the extent to which transmission facilities, individually or in the aggregate, provide for maintaining reliability and sharing reserves, production cost savings and congestion relief, and/or meeting Public Policy Requirements.

and

Interregional Cost Allocation Principle 1: The costs of a new interregional transmission facility must be allocated to each transmission planning region in which that transmission facility is located in a manner that is at least roughly commensurate with the estimated benefits of that transmission facility in each of the transmission planning regions. In determining the beneficiaries of interregional transmission facilities, transmission planning regions may consider benefits including, but not limited to, those associated with maintaining reliability and sharing reserves, production cost savings and congestion relief, and meeting Public Policy Requirements.[777]

655. However, the Commission stated that it was not prescribing a particular definition of ''benefits'' or ''beneficiaries'' in Order No. 1000.[778] In the Commission's view, the proper context for consideration of these matters is in the regional stakeholder meetings in the first instance, followed by Commission consideration of these matters on review of compliance proposals and the record before the Commission.[779]

656. The Commission also stated that if a non-public utility transmission provider makes the choice to become part of the transmission planning region and it is determined by the transmission planning process to be a beneficiary of certain transmission facilities selected in the regional transmission plan for purposes of cost allocation, that non-public utility transmission provider is responsible for the costs associated with such benefits.[780]

657. Additionally, in Order No. 1000, the Commission found that issues related to the generator interconnection process and to interconnection cost recovery were outside the scope of the rulemaking proceeding.[781] The Commission stated that Order No. 2003 [782] sets forth the procedures for the interconnection of a large generating transmission facility to the bulk power system.[783] Additionally, the Commission emphasized that Order No. 1000 did not set forth any new requirements with respect to such procedures for interconnecting large, small, or wind or other generation facilities.[784] Therefore, the Commission determined that Order No. 1000 was not the proper proceeding for commenters to raise issues about the interconnection agreements and procedures under Order Nos. 2003, 2006 [785] or 661.[786]

a. Requests for Rehearing or Clarification

658. Several petitioners seek rehearing or clarification regarding the lack of a definition of ''benefits'' in Order No. 1000. Illinois Commerce Commission argues that by failing to establish definitions and standards for transmission providers to implement in identifying project benefits, the Commission has placed transmission providers in conflict with majority desires in the stakeholder process because an RTO is obligated to act in the interests of its transmission owning members. It argues that RTO behavior has been more accommodating to transmission owning utilities than captive ratepayers, and this issue will be exacerbated with less Commission oversight.

659. Arizona Cooperative and Southwest Transmission also argue that there is insufficient Commission oversight of the definition and measurement of benefits. It argues that ''benefits'' can, within the context of a network, become so pliable as to become meaningless, especially as applied to individual situations. Arizona Cooperative and Southwest Transmission add that different outcomes are apt to flow from how benefits are defined. Public utilities may value needs and interests differently from other stakeholders, and customers and entities will not all have the same needs and interests. Arizona Cooperative and Southwest Transmission are concerned that it may be deemed to receive benefits that have little or nothing to do with its needs.

660. Georgia PSC and Florida PSC seek clarification of the definition of benefits and what constitutes too narrow or too broad a definition. Florida PSC asserts that leaving this question to the stakeholder and subsequent compliance process creates the possibility that regions will adopt a definition of benefits that does not meet whatever undefined standard the Commission may have in mind. It argues that this approach limits regional autonomy in an undefined way, even though the Commission states that regions are free to determine their own definitions of benefits.

661. Georgia PSC and Florida PSC also seek clarification of what benefits must be quantifiable and based on existing policies in state and federal law. Florida PSC argues that ambiguities on this issue and what constitutes too broad or narrow a definition of benefits violate the Due Process Clause ''fair notice'' requirement.[787]

662. Other petitioners argue that the definitions of ''benefits'' and ''beneficiary'' were left too broad.[788] Kentucky PSC argues that the Commission erred in failing to define ''cost causer'' and ''beneficiary.'' [789] It asserts that recently there has been considerable dispute over the meaning of cost causer and when an entity becomes a beneficiary of a new or expanded facility developed by others. Kentucky PSC is concerned that there is no requirement that cost allocation processes account for proximity to a project, which it asserts is directly related a project's actual benefits in terms of improving reliability, reducing congestion, and opening markets. It contends that it appears that a project may be eligible for cost allocation solely

[776] *Id.* P 607.

[777] *Id.* P 622.

[778] *Id.* P 624.

[779] *Id.*

[780] *Id.* P 629.

[781] *Id.* P 760.

[782] Order No. 2003, 68 FR 49846, FERC Stats. & Regs. ¶ 31,146, *order on reh'g,* Order No. 2003–A, 69 FR 15932, FERC Stats. & Regs. ¶ 31,160, *order on reh'g,* Order No. 2003–B, 70 FR 265, FERC Stats. & Regs. ¶ 31,171, *order on reh'g,* Order No. 2003–C, 70 FR 37661, FERC Stats. & Regs. ¶ 31,190, *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs* v. *FERC,* 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied,* 552 U.S. 1230 (2008).

[783] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 760.

[784] *Id.*

[785] Order No. 2006, 70 FR 34189, FERC Stats. & Regs. ¶ 31,180, *order on reh'g,* Order No. 2006–A, 70 FR 71760, FERC Stats. & Regs. ¶ 31,196, *order granting clarification,* Order No. 2006–B, 71 FR 42587, FERC Stats. & Regs. ¶ 31,221.

[786] Order No. 661, 70 FR 34993 (Jun. 16, 2005), FERC Stats. & Regs. ¶ 31,186, *order on reh'g,* Order No. 661–A, FERC Stats. & Regs. ¶ 31,198.

[787] Florida PSC at 8 (citing *Trinity Broadcasting of Fla., Inc.* v. *FCC,* 211 F.3d 618, 628 (D.C. Cir. 2000)).

[788] *See, e.g.,* Coalition for Fair Transmission Policy; and PSEG Companies.

[789] Kentucky PSC at 5.

due to its ability to meet the public policy requirements of state or federal governments.[790] Kentucky PSC explains that there is no requirement that a state have a need for a project, which will result in ratepayers paying for projects that may not be located within their state and that are designed to meet other states' public policy requirements. It maintains that to exempt a state's ratepayers from cost allocation only if they will not benefit at present or in a ''future scenario'' appears to enable the majority in a regional planning entity to decide that a particular state's legislature will, or should, ultimately enact certain public policies or that the federal government will do so.

663. Likewise, Coalition for Fair Transmission Policy argues that not limiting the definition of ''benefits'' and ''beneficiary'' will lead to uncertainty and dispute.[791] It states that a beneficiary-pays approach is appropriate for certain types of projects, such as projects driven by reliability compliance obligations, because the relationship between specific transmission projects, reliability impacts, and the benefits of reliability are well established and capable of examination within a framework of existing transmission planning horizons and study methodologies. However, Coalition for Fair Transmission Policy asserts that it is difficult to define benefits and beneficiaries in a way that is just and reasonable and objectively verifiable for projects such as upgrades driven by economics and/or public policy requirements.

664. According to Coalition for Fair Transmission Policy, failure to define potential benefits correctly on compliance will have adverse economic and policy impacts. For instance, it maintains that if benefits are defined to include broad societal benefits of building renewables in a certain area, and that definition is used to justify cost socialization of transmission projects to that area, the generator or customer will not face the true costs of their resource decisions. Buyers may decide to buy from remote renewable resources that require long-distance transmission, rather than potentially lower cost local renewable resources, because they do not have to pay the full transmission costs. According to Coalition for Fair Transmission Policy, competitive wholesale markets using locational-marginal pricing would at that point begin to see price signals break down and become inefficient. It also argues that siting may become more difficult because those required to pay for lines they do not see benefit from will litigate both the cost and siting-approval processes.

665. Coalition for Fair Transmission Policy urges the Commission to limit regions to considering only benefits that: (1) Occur within the typical transmission planning horizon of the public utilities within the region that can be measured or projected through the kinds of transmission planning studies that are normally conducted; (2) are not speculative; and (3) are not based on ''societal'' benefits that are not embodied in existing federal and state public policy requirements.[792] It also argues that the Commission should clarify that regional transmission planning may not adopt presumptions that broad categorizations of types or classes of transmission lines driven by economic or public policy requirements have broad benefits and should be allocated widely. Also, Coalition for Fair Transmission Policy and North Carolina Agencies argue that the Commission should require that those seeking cost allocations for individual transmission projects be able to demonstrate quantifiable, observable and tangible reliability and economic benefits with reasonable particularity that is tied directly to those who will be required to pay under a cost allocation methodology. North Carolina Agencies argue that both the FPA and Commission precedent require the allocation of costs in proportion to the real reliability and economic benefits resulting from a transmission investment that can be measured or projected within the planning horizon.

666. In addition, Coalition for Fair Transmission Policy argues that the Commission should revise its cost allocation principles to assure that benefits are defined in way that conforms with what it asserts are established cost-causation standards, which include, among other things, tying cost allocation to the taking of transmission service.[793]

667. Coalition for Fair Transmission Policy maintains that while Order No. 1000 states that the Commission will fill in the gaps that it left in Order No. 1000 through the process of accepting or rejecting or requiring modification of proposed definitions, the courts have rejected this approach as contrary to law, arbitrary and capricious.[794] Coalition for Fair Transmission Policy asserts that the Commission must supply sufficient explanation to provide a reasonable benchmark and guidance in the development of compliance filings. Coalition for Fair Transmission Policy asserts that the lack of additional guidance creates a risk of stalemate at the regional level and a likelihood that the Commission ultimately would have to define the terms for a region. It argues that this would essentially penalize public utility transmission providers because the process is designed to fail and then be saved by the Commission.

668. Illinois Commerce Commission argues that there is no way to identify ''more efficient or cost effective'' transmission projects in the planning process without a meaningful estimation of benefits, and there is no way to assess whether a transmission provider has complied with the Commission's directive that costs be allocated at least roughly commensurate with benefits unless the level of benefits expected to be provided by a project to each load-serving entity have been determined.[795] It adds that if the Commission's requirements are not clear, there will be no basis to make compliance findings or to detect planning and cost allocation abuses.

669. Illinois Commerce Commission and MISO Northeast seek clarification that generators are subject to regional cost allocation. Illinois Commerce Commission requests clarification that costs can be recovered when the planning itself is undertaken to accommodate the interconnection of particular generators. It notes that Order No. 1000 ruled out participant funding as an acceptable regional or interregional cost allocation method, but Illinois Commerce Commission states that participant funding has applied to generation developers that agree to fund transmission network upgrades to enable their generator to be interconnected to the network. Illinois Commerce Commission requests clarification that Order No. 1000 does not prohibit transmission providers from finding generators to be cost causers or beneficiaries of new transmission facilities developed pursuant to the regional or interregional planning process and allocating costs to those generators accordingly. MISO Northeast likewise requests that the

[790] Kentucky PSC at 6 (quoting Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 585).

[791] Coalition for Fair Transmission Policy at 8.

[792] Coalition for Fair Transmission Policy at 13.

[793] Coalition for Fair Transmission Policy at 15–16 (citing *Midwest ISO Transmission Owners* v. *FERC,* 373 F.3d 1361, 1369 (D.C. Cir. 2004); citing *Illinois Commerce Commission* v. *FERC,* 576 F.3d at 474–77; citing *Pacific Gas & Electric Co.* v. *FERC,* 373 F.3d 1315, 1321 (D.C. Cir. 2004); quoting *Algonquin Gas Transmission Co.* v. *FERC,* 948 F.2d 1305, 1312–14 (D.C. Cir. 1991)).

[794] Coalition for Fair Transmission Policy at 14 (citing *Appalachian Power Co.* v. *EPA,* 208 F.3d 1015, 1020 (D.C. Cir. 2000)).

[795] Illinois Commerce Commission at 10.

Commission clarify that any regionwide cost allocation method adopted pursuant to Order No. 1000 must allocate costs to generators and end-users commensurate with the share of public policy benefits that they receive.

670. In contrast, NextEra argues that generators should not be responsible for costs not specified in interconnection agreements. It explains that Order No. 2003 recognized that generators must be able to identify all risks prior to entering into an interconnection agreement and commencing construction when it concluded that interconnection customers should only be responsible for costs specifically identified in their interconnection agreements.[796] It argues that it follows that generators should not be responsible for costs not identified in their interconnection agreements, and asserts that if costs could be so allocated, it would make the cost of project financing prohibitive because lenders would likely seek protection for such contingencies. NextEra thus urges the Commission to clarify that generators and other tie line owners will not be responsible for costs not specified in their interconnection agreements, which it argues is consistent with Order No. 1000's conclusion that costs cannot be involuntarily allocated to non-beneficiaries. Otherwise, NextEra argues, such unknowable and unworkable cost allocation creates unjust and unreasonable risks and would be inconsistent with Order No. 2003.

671. Illinois Commerce Commission also takes issue with the requirement in Order No. 1000 that cost allocation methods consider the benefits and costs of groups of new transmission facilities rather than requiring that each project satisfy the Commission's principles and requirements on its own merits. It argues that a portfolio approach to transmission planning allows the approval of projects that, when considered individually, are not cost beneficial.

672. Illinois Commerce Commission states that if individual projects are cost beneficial, and in the aggregate their estimated benefits are roughly commensurate with a postage stamp allocation, then an allocation according to the benefits of each project individually would result in an allocation roughly equivalent with a postage stamp allocation. It argues that this scenario would render the postage stamp allocation unnecessary. Therefore, Illinois Commerce Commission argues that the Commission erred by including the word ''aggregate'' in Principle 1 because it allows transmission providers to avoid demonstrating that each individual project is cost beneficial. It also argues that the Commission violated the FPA and case precedent in failing to remove postage stamp rates as a possible cost allocation method. Specifically, it maintains that it is incorrect to conclude that even when ''all customers within a transmission planning region are found to benefit from the use or availability of a transmission facility or class or group of transmission facilities,'' they all benefit roughly equally.[797] Illinois Commerce Commission also points to the Seventh Circuit's statement that an assertion of generalized system benefits is not sufficient to justify a cost allocation and that alleged benefits, without specific evidentiary support, are too speculative to be considered.

673. Finally, ELCON, AF&PA, and the Associated Industrial Groups argue that use of a postage stamp rate for cost allocation at the regional or interregional level is a form of cost socialization, and it is therefore inconsistent with the cost causation principle. They also maintain that the statement by the court in *Illinois Commerce Commission* that benefits be at least roughly commensurate with costs requires one to conclude that a postage stamp rate is an impermissible form of cost causation.

i. Commission Determination

674. We affirm Order No. 1000 and therefore deny those arguments requesting us to prescribe a particular definition of ''benefits'' or ''beneficiaries.'' As the Commission found in Order No. 1000, the proper context for further consideration of these matters is on review of compliance proposals and a record before us. Many of the petitioners here essentially expound on concerns they raised in the rulemaking proceeding that more specificity in Order No. 1000 itself is required because an overly broad or overly narrow definition of beneficiary or beneficiaries could lead to cost allocations that do not correspond to cost causation. However, as stated in Order No. 1000, we believe that concerns regarding overly narrow or broad interpretations of benefits will be addressed in the first instance during the process of public utility transmission providers consulting with their stakeholders as part of the development of a compliance filing. If such interpretations should emerge, we can more effectively ensure that the term is not given too narrow or broad a meaning by considering a specific proposal and a record than by attempting to anticipate and rule on all possibilities before the fact. This point applies equally to those petitioners that note the potential difficulties in quantifying benefits.[798] For this reason, we decline to adopt any of the many suggestions offered by petitioners in their requests for rehearing and clarification, including those who argue that only certain benefits, such as reliability benefits, should be considered, because determining other types of benefits is difficult or speculative.

675. In response to Illinois Commerce Commission's concern that by not providing a definition of ''benefits'' in Order No. 1000 the Commission would exacerbate an RTO's ability to favor its transmission owning members to the detriment of other stakeholders, we first note that we do not accept the premise that RTOs as a rule engage in such behavior. In any event, when each public utility transmission provider, including an RTO, proposes its cost allocation method or methods, the Commission will review the method or methods, including how benefits and beneficiaries are defined, to determine whether it complies with the requirements of Order No. 1000. This review will include an analysis of whether the cost allocation method or methods comply with Principle 1, which requires that the cost allocation method or method result in an allocation of costs roughly commensurate with benefits. If the compliance filing is unclear on these matters or if parties take issue with aspects of the compliance filing, such as the definition of benefits, the Commission will address those issues at that time.

676. We also disagree with petitioners, such as Georgia PSC and Florida PSC, who assert that by not defining benefits the Commission is limiting regional autonomy. By permitting public utility transmission providers in a region to define benefits collectively together with regional stakeholders, the Commission is enabling them to account for regional differences rather than prescribing a one-size-fits-all method that might not do so as effectively. We also decline to grant the requests of Georgia PSC and Florida PSC for clarification of what benefits must be quantifiable based on

[796] NextEra at 18 (citing Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 421).

[797] Illinois Commerce Commission at 16.

[798] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at PP 624–25.

existing policies in state and federal law. Consistent with the discussion above, we believe that this is a matter that is best addressed in the first instance by the public utility transmission providers and their stakeholders in the development of the cost allocation methods for their regions. Furthermore, Florida PSC's argument that the fair notice requirement of the Due Process Clause requires a definition of benefits is without merit, as Florida PSC and all other stakeholders will have ample opportunity to participate in both in the development of the cost allocation methods for their regions, as well as in the Commission proceeding to review the compliance filings that incorporate those cost allocation methods.

677. Moreover, we note that, as applied by the courts, the Due Process standard has been held to allow for flexibility in the wording of an agency's rules and for a reasonable breadth in their construction.[799] In fact, the courts have recognized that ''by requiring regulations to be too specific, [courts] would be opening up large loopholes allowing conduct which should be regulated to escape regulation.'' [800] As the Supreme Court has noted, the degree of vagueness tolerated by the Constitution depends in part on the nature of the rules at issue.[801] In the case of economic regulation, the Supreme Court has found that the vagueness test must be applied in a less strict manner because, among other things, ''the regulated enterprise may have the ability to clarify the meaning of the regulation by its own inquiry, or by resort to an administrative process.'' [802]

678. We also note several petitioners' concerns that the definitions of ''benefits,'' ''beneficiary,'' and ''cost causer,'' are too broad, which they argue will lead to further disputes. As the Commission stated in Order No. 1000, the Commission is allowing flexibility to accommodate a variety of approaches which can better advance the goals of Order No. 1000, recognizing that regional differences may warrant distinctions in cost allocation method or methods.[803] This flexibility is provided so that public utility transmission providers and their stakeholders can develop cost allocation methods that best meet their region's needs. The Commission established the Cost Allocation Principles to provide general guidance to public utility transmission providers to limit uncertainty as they develop their compliance filings. However, for those cost allocation methods to be accepted by the Commission as Order No. 1000-compliant, they will have to clearly and definitively specify the benefits and the class of beneficiaries. Accordingly, we disagree with the premise of some petitioners' arguments that there will be uncertainty once the Commission accepts the cost allocation method or methods in exactly who is a beneficiary and how such determinations are made. That is the very purpose of requiring an *ex ante* cost allocation method: To be clear upfront about who is benefitting so that disputes are minimized and so that the transmission facilities selected in the regional transmission plan for purposes of cost allocation are more likely to be constructed.

679. Additionally, we agree with Illinois Commerce Commission's argument that there is no way to identify ''more efficient or cost effective'' transmission solutions, or to assess whether costs are being allocated at least roughly commensurate with benefits, without a meaningful estimation of benefits. However, we do not believe that this requires any change or clarification to Order No. 1000. As we explain above, while Order No. 1000 does not define benefits and beneficiaries, it does require the public utility transmission providers in each region to be definite about benefits and beneficiaries for purposes of their cost allocation methods. Once beneficiaries are identified, public utility transmission providers would then be able to identify what is the more efficient or cost effective transmission solution or assess whether costs are being allocated at least roughly commensurate with benefits.

680. With respect to generators being identified as beneficiaries and ultimately responsible for costs, we find that just as each transmission planning region retains the flexibility to define benefit and beneficiary, the public utility transmission providers in each transmission planning region, in consultation with their stakeholders, may consider proposals to allocate costs directly to generators as beneficiaries that could be subject to regional or interregional cost allocation. However, we emphasize that any effort to do so must not be inconsistent with the generator interconnection process under Order No. 2003 [804] because, as we stated in Order No. 1000, the generator interconnection process and interconnection cost recovery are outside the scope of this rulemaking. With this said, however, we are not minimizing the importance of evaluating the impact of generation interconnection requests during transmission planning, nor limiting the ability of public utility transmission providers to take requests for generator interconnections into account in developing assumptions to be used in the transmission planning process.[805] While we agree with NextEra that interconnection costs would be specified in interconnection agreements, we deny NextEra's request that the Commission clarify those are the only transmission costs for which generators could be responsible. The Commission determined in Order No. 2003 that interconnection service does not convey the right to flow output of the interconnection customer's generating facility onto the transmission provider's transmission system and does not constitute a reservation of transmission capacity.[806] Order No. 2003 states that the interconnection customer, load or other market participant would have to request either point-to-point or Network Integration Transmission Service under the Transmission Provider's OATT in order to receive the delivery service that is a prerequisite to flowing power onto the system.[807] As such, the interconnection customer could be subject to charges associated with transmission service that are not addressed in its interconnection agreement.

681. We affirm the Commission's finding in Order No. 1000 that in determining the beneficiaries of transmission facilities, Regional Cost Allocation Principle 1 should permit a regional transmission planning process to ''consider benefits including, but not limited to, the extent to which transmission facilities, individually or in the aggregate, provide for maintaining reliability and sharing reserves, production cost savings and congestion relief, and/or meeting Public Policy

[799] *See Grayned* v. *City of Rockford,* 408 U.S. 110 (1971) (holding that an anti-noise ordinance was not vague where the words of the ordinance ''are marked by flexibility and reasonable breadth, rather than meticulous specificity.'').

[800] *See Ray Evers Welding Co.* v. *OSHRC,* 625 F.2d 726, 730 (6th Cir. 1980).

[801] *See Village of Hoffman Estates* v. *The Flipside, Hoffman Estates, Inc.,* 455 U.S. 489 (1981).

[802] *See id.* at 498.

[803] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 624.

[804] Order No. 2003, 68 FR 49846, FERC Stats. & Regs. ¶ 31,146, *order on reh'g,* Order No. 2003–A, 69 FR 15932, FERC Stats. & Regs. ¶ 31,160, *order on reh'g,* Order No. 2003–B, 70 FR 265, FERC Stats. & Regs. ¶ 31,171, *order on reh'g,* Order No. 2003–C, 70 FR 37661, FERC Stats. & Regs. ¶ 31,190, *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs* v. *FERC,* 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied,* 552 U.S. 1230 (2008).

[805] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 760.

[806] Order No. 2003, 68 FR 49846, FERC Stats. & Regs. ¶ 31,146 at P 767.

[807] *Id.*

Requirements.'' [808] Order No. 1000 was not intended to restrict regional choice in the transmission planning and cost allocation process as petitioners request.

682. Accordingly, we continue to believe that it is appropriate to allow public utility transmission providers in a transmission planning region to propose a cost allocation method that considers the benefits and costs of a *group* of new transmission facilities, although they are not required to do so.[809] As such, we deny Illinois Commerce Commission's arguments that ask us to decide in advance that such an approach is inappropriate and at odds with cost causation. We reiterate that if public utility transmission providers in a region in consultation with their regional stakeholders choose to propose and adequately support a cost allocation method or methods that considers the benefits and costs of a group of new transmission facilities, Order No. 1000 would not require a facility-by-facility showing, so long as the aggregate cost of the transmission facilities in the group is allocated roughly commensurate with aggregate benefits.[810] Such an approach could be reasonable if it, for instance, enables a transmission planning region to prioritize its new transmission facilities in such a way as to ensure benefits from the facilities and maximize the number of system users who will share in those benefits.

683. We also decline to forbid in advance the potential use of a postage stamp cost allocation method. We continue to believe that a postage stamp cost allocation method may be appropriate where all customers within a specified transmission planning region are found to benefit from the use or availability of a transmission facility or class or group of transmission facilities, especially if the distribution of benefits associated with a class or group of transmission facilities is likely to vary considerably over the long depreciation life of the transmission facilities amid changing power flows, fuel prices, population patterns, and local economic considerations.[811] As such, we believe that public utility transmission providers, if they choose to do so in consultation with stakeholders, should be permitted to make the case in their compliance filings that a postage stamp cost allocation is consistent with Principle 1's requirement that all costs be allocated roughly commensurate with benefits. To this end, we agree with Illinois Commerce Commission that any such case would have to do more than make a mere assertion of generalized system benefits. Last, we decline to address Illinois Commerce Commission's arguments related to the MISO MVP proceeding in Docket No. ER10–1791–000 as outside the scope of this proceeding.

3. Cost Allocation Principle 2—No Involuntary Allocation of Costs to Non-Beneficiaries

a. Final Rule

684. The Commission adopted the following Cost Allocation Principle 2 for both regional and interregional cost allocation:

> Regional Cost Allocation Principle 2: Those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of those transmission facilities.

and

> Interregional Cost Allocation Principle 2: A transmission planning region that receives no benefit from an interregional transmission facility that is located in that region, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of that transmission facility.[812]

685. The Commission also required that every cost allocation method or methods provide for allocation of the entire prudently incurred cost of a transmission project to prevent stranded costs.[813]

b. Requests for Rehearing or Clarification

686. PSEG Companies argue that Principle 2's ''likely future scenarios'' language is problematic because it could easily result in the expansion of the class of customers that are labeled beneficiaries as more scenarios are introduced, thus making cost allocation determinations more likely to be inexact and speculative.[814] They further state that Order No. 1000's statement that benefits must be ''identifiable'' does not cure the defect, particularly because Order No. 1000 allows not only transmission providers to identify the beneficiaries of proposed projects based on ''likely future scenarios,'' but also allows them to develop such scenarios based on potential public policy requirements.[815] PSEG Companies argue that allowing transmission providers to exercise unfettered discretion in identifying beneficiaries under future scenarios will allow them to act arbitrarily and capriciously, and that the expansive interpretations of ''benefits'' and ''beneficiaries'' would permit the allocation of costs based on tenuous associations with benefits, contrary to *Illinois Commerce Commission*.[816]

687. ITC Companies seek clarification that a ''likely future scenario'' that would justify an allocation of costs for new transmission facilities includes the transmission planning scenarios being used by a transmission provider to prepare a regional transmission plan.[817] ITC Companies state that one helpful clarification would be to confirm that, if a project is shown to have benefits for a zone or customer in one or more of the planning scenarios generally used by the transmission provider to prepare a regional transmission plan, those benefits satisfy Principle 2 and support the allocation of costs to the beneficiaries.

688. Long Island Power Authority seeks clarification that entities not subject to a Public Policy Requirement will have an opportunity to demonstrate this fact for purposes of cost allocation. Long Island Power Authority acknowledges, however, that where an approved project provides multiple benefits, it could be appropriate for an entity to be allocated that portion of a project's costs that are unrelated to fulfilling certain public policy goals, provided that the economic and reliability related costs were allocated according to the economic and reliability procedures of the region, or as agreed upon by neighboring regions.

c. Commission Determination

689. We affirm Order No. 1000's adoption of Regional and Interregional Cost Allocation Principle 2. Accordingly, we deny PSEG Companies' request for rehearing, which largely repeats arguments it made in the rulemaking proceeding. The Commission disagreed with PSEG Companies in Order No. 1000 that basing a determination of who constitutes a ''beneficiary'' on ''likely future scenarios'' necessarily would result in inexact and speculative proposed transmission plans and cost allocation methods.[818] The Commission explained that scenario analysis is a common feature of electric power

[808] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 622.

[809] *Id.* P 627.

[810] *Id.* P 641.

[811] *Id.* P 605.

[812] *Id.* P 637.

[813] *Id.* P 640.

[814] PSEG Companies at 41–42.

[815] PSEG Companies at 42–43.

[816] PSEG Companies at 43–44. PSEG Companies also cite to *Transcontinental Gas Pipe Line Corp.*, 112 FERC ¶ 61,170 (2005), where the Commission rejected reliance on a claim of generalized system benefits as a basis for allocating gas pipeline upgrade costs to existing shippers.

[817] ITC Companies at 14.

[818] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 626.

system planning, and that it believed that public utility transmission providers are in the best position to apply it in a way that achieves appropriate results in their respective transmission planning regions.[819] We disagree that the use of ''likely future scenarios'' and Public Policy Requirements will expand the class of customers who will be identified as beneficiaries. The Commission stated in the discussion on Cost Allocation Principle 1 above that the identification of beneficiaries is based on the principle of cost causation. Accordingly, the scenario analysis is not unfettered. It is limited to scenarios in which a beneficiary is identified as such on the basis of the cost causation principle.

690. In response to ITC Companies, we therefore clarify that public utility transmission providers may rely on scenario analyses in the preparation of a regional transmission plan and the selection of new transmission facilities for cost allocation. If a project or group of projects is shown to have benefits in one or more of the transmission planning scenarios identified by public utility transmission providers in their Commission-approved Order No. 1000-compliant cost allocation methods, Principle 2 would be satisfied.

691. In response to Long Island Power Authority's request that the Commission clarify that entities have the opportunity to demonstrate that a transmission project proposed to meet a given Public Policy Requirement is not applicable to them and provides no benefit to them, we affirm the Commission's statement in Order No. 1000 that consideration of regional transmission needs driven by Public Policy Requirements must follow the cost allocation principles. For instance, Cost Allocation Principle 1 makes clear that Long Island Power Authority will be allocated only costs that are roughly commensurate with the benefits it receives from a transmission facility or facilities. Additionally, Cost Allocation Principle 2 states that those that receive no benefit from new transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of those transmission facilities.[820] Given this, if it is true that Long Island Power Authority would not benefit from a transmission project or group of projects designed to meet a regional transmission need driven by a Public Policy Requirement, the transmission planning region's cost allocation method or methods would not be permitted to allocate any costs to it. As Long Island Power Authority acknowledges, even if it does not need the transmission facility to meet a Public Policy Requirement of its own, it nevertheless may receive other economic or reliability benefits from a proposed transmission facility and then the cost allocation method may allocate the costs for the economic or reliability benefits received.

[819] *Id.*

[820] *Id.* P 219.

4. Cost Allocation Principle 3—Benefit to Cost Threshold Ratio

a. Final Rule

692. The Commission adopted the following Cost Allocation Principle 3 for both regional and interregional cost allocation:

> Regional Cost Allocation Principle 3: If a benefit to cost threshold is used to determine which transmission facilities have sufficient net benefits to be selected in a regional transmission plan for the purpose of cost allocation, it must not be so high that transmission facilities with significant positive net benefits are excluded from cost allocation. A public utility transmission provider in a transmission planning region may choose to use such a threshold to account for uncertainty in the calculation of benefits and costs. If adopted, such a threshold may not include a ratio of benefits to costs that exceeds 1.25 unless the transmission planning region or public utility transmission provider justifies and the Commission approves a higher ratio.

and

> Interregional Cost Allocation Principle 3: If a benefit-cost threshold ratio is used to determine whether an interregional transmission facility has sufficient net benefits to qualify for interregional cost allocation, this ratio must not be so large as to exclude a transmission facility with significant positive net benefits from cost allocation. The public utility transmission providers located in the neighboring transmission planning regions may choose to use such a threshold to account for uncertainty in the calculation of benefits and costs. If adopted, such a threshold may not include a ratio of benefits to costs that exceeds 1.25 unless the pair of regions justifies and the Commission approves a higher ratio.[821]

693. The Commission stated that Cost Allocation Principle 3 did not require the use of a benefit to cost ratio threshold.[822] However, if a transmission planning region chooses to have such a threshold, the principle limited the threshold to one that is not so high as to block inclusion of many worthwhile transmission projects in the regional transmission plan.[823] Further, it allowed public utility providers in a transmission planning region to use a lower ratio without a separate showing and to use a higher threshold if they justify it and the Commission approves a greater ratio.[824]

[821] *Id.* P 646.

[822] *Id.* P 647.

[823] *Id.*

b. Request for Rehearing or Clarification

694. Transmission Dependent Utility Systems seek clarification, or in the alternative rehearing, that stakeholders will have access to the data necessary to replicate any benefit-to-cost analysis that public utility transmission providers conduct pursuant to Cost Allocation Principle 3. They state that the Commission did not respond in Order No. 1000 to their argument that Cost Allocation Principle 3 be modified to ensure that implementation of any cost benefit analysis is transparent to load serving entity transmission customers.

c. Commission Determination

695. We find that it is not necessary to modify Cost Allocation Principle 3 to require transparency in the implementation of the benefit to cost analysis because this requirement already exists in Cost Allocation Principle 5. The language in Regional Cost Allocation Principle 5 and Interregional Cost Allocation Principle 5 states that ''[t]he cost allocation method and data requirements for determining benefits and identifying beneficiaries * * * must be transparent with adequate documentation to allow a stakeholder to determine how they were applied.''[825] Accordingly, we believe that it is clear that the transparency requirement in Cost Allocation Principle 5 applies to any benefit to cost analysis subject to Cost Allocation Principle 3, such that all data relating to the benefit to cost ratio must be transparent. Additionally, the Order No. 890 transparency principle requires ''transmission providers to disclose to all customers and other stakeholders the basic criteria, assumptions, and data that underlie their transmission system plans.''[826]

5. Cost Allocation Principle 4—Allocation To Be Solely Within Transmission Planning Region(s) Unless Those Outside Voluntarily Assume Costs

a. Final Rule

696. The Commission adopted the following Cost Allocation Principle 4 for both regional and interregional cost allocation:

[824] *Id.*

[825] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 668.

[826] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 471.

Regional Cost Allocation Principle 4: The allocation method for the cost of a transmission facility selected in a regional transmission plan must allocate costs solely within that transmission planning region unless another entity outside the region or another transmission planning region voluntarily agrees to assume a portion of those costs. However, the transmission planning process in the original region must identify consequences for other transmission planning regions, such as upgrades that may be required in another region and, if the original region agrees to bear costs associated with such upgrades, then the original region's cost allocation method or methods must include provisions for allocating the costs of the upgrades among the beneficiaries in the original region.

and

Interregional Cost Allocation Principle 4: Costs allocated for an interregional transmission facility must be assigned only to transmission planning regions in which the transmission facility is located. Costs cannot be assigned involuntarily under this rule to a transmission planning region in which that transmission facility is not located. However, interregional coordination must identify consequences for other transmission planning regions, such as upgrades that may be required in a third transmission planning region and, if the transmission providers in the regions in which the transmission facility is located agree to bear costs associated with such upgrades, then the interregional cost allocation method must include provisions for allocating the costs of such upgrades among the beneficiaries in the transmission planning regions in which the transmission facility is located.[827]

b. Requests for Rehearing or Clarification

697. Several petitioners argue that Principle 4 is inconsistent with cost causation.[828] Energy Future Coalition Group and AEP assert that the Commission should require beneficiaries in adjoining regions to contribute to the costs of new transmission facilities. They assert that otherwise it is likely that intraregional transmission projects that are in the public interest, and would benefit customers in multiple regions, will fail.

698. Energy Future Coalition Group argues that the Commission disregarded the beneficiary pays principle by providing that costs for a transmission facility located in one region may be allocated to beneficiaries in another region only if those beneficiaries volunteer to pay those costs.[829] Energy Future Coalition Group, Joint Petitioners, and AEP add that the Commission's decision fails to address the concern about free-riders. AEP argues that the Commission's decision is contrary to its findings that the FPA and court precedent[830] require all rates to ''reflect to some degree the costs actually caused by the customer who must pay them,'' and ''[t]o the extent that a utility benefits from the costs of new facilities, it may be said to have 'caused' a part of those costs to be incurred.''[831] AEP argues that this cost causation principle applies to all identifiable beneficiaries, not only those who voluntarily agree to pay the costs associated with the facilities. AEP further argues that the Commission's policy results in unjust and unreasonable rates that discriminate against a set of customers.

699. Joint Petitioners further argue that it is arbitrary to follow the beneficiary pays principle within a region, but not across regions, when the Commission has declined to define what these regions should be and when they may have little or no electrical significance. AEP makes a similar argument. Energy Future Coalition Group and AEP also argue that there will be a perverse incentive to create regional boundaries for the purpose of evading cost responsibility for nearby transmission facilities. AEP adds that the choice between a regional and an interregional project configuration would make an enormous difference with respect to cost allocation, but that there may be very little difference in the distribution of benefits or the physical design of the project.

700. Energy Future Coalition Group notes that the Commission held that within a given region, costs of a new project built wholly within the service territory of one transmission provider can be allocated to beneficiaries throughout the region if there is a clear regional benefit. It argues that this is directly analogous to the potential for extraregional benefits from a regional transmission project and asserts that the Commission unaccountably reaches the opposite conclusion as to the possibility of broader interregional cost allocation for a regional project with broader benefits.

701. Energy Future Coalition Group argues that the Commission can ensure that the attenuated assessments of benefits are avoided by providing that interregional planning and cost allocation are required for a project located wholly within one region only when: (1) The extraregional benefits are directly related to the proposed transmission project, not to assumed electricity market reactions or influences; (2) the identified extraregional benefits are enjoyed in an adjacent planning region; and (3) the extraregional benefits are similar in nature to the benefits for which costs are proposed to be allocated within the region where the facility is proposed.[832]

702. Joint Petitioners suggest that to limit the stakeholder burden of monitoring transmission planning in other regions, and in keeping with the evidence of the broad benefits of extra high voltage transmission, Regional Cost Allocation Principle 4 and Interregional Cost Allocation Principle 4 should be limited to transmission projects less than 345 kV. Joint Petitioners recommend that for projects at 345 kV and above, the Commission should expand its interregional coordination requirements to require that a regional planning entity notify its neighbors when it is considering such an extra high voltage project. Joint Petitioners state that the neighboring transmission planning region then could have an opportunity to participate in the planning process through which the project's beneficiaries will be determined or may conduct its own planning process to consider the project. They suggest similar opportunities should be provided in the regional planning process.

703. Similarly, AEP proposes that the Commission expand the scope of ''interregional transmission facilities'' to include new facilities located solely within a single region in certain circumstances, such as where the facilities are extra high voltage facilities that provide demonstrable benefits to the neighboring region.[833] AEP adds that identification of potential beneficiaries will be strictly limited to a region that adjoins the region in which the facility will be located, and would specifically exclude any region that does not have a direct interconnection with the region in which the new facility is located. AEP asserts that this approach addresses several of the Commission's concerns and does not place any undue burden on stakeholders.[834]

[827] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 657.

[828] *See, e.g.,* Joint Petitioners; Energy Future Coalition Group; and AEP.

[829] Energy Future Coalition Group at 9 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 582).

[830] AEP at 7 (citing *Illinois Commerce Commission* v. *FERC,* 576 F.3d 470 (7th Cir. 2009); *K N Energy, Inc.* v. *FERC,* 968 F.2d 1295, 1300 (D.C. Cir. 1992); *Midwest ISO Transmission Owners* v. *FERC,* 373 F.3d 1361, 1369 (D.C. Cir. 2004); *Sithe/Independent Power Partners, L.P.* v. *FERC,* 285 F.3d 1, 5 (D.C. Cir. 2002)).

[831] AEP at 8 (quoting *Illinois Commerce Commission* v. *FERC,* 576 F.3d at 476).

[832] Energy Future Coalition Group at 11.

[833] AEP at 14.

[834] AEP adds that the Commission should find that the transmission planning provisions of the

704. MISO argues that Cost Allocation Principle 4 should not preclude an RTO from allocating to a withdrawing RTO member the cost of eligible transmission upgrades located solely in the RTO and approved before the withdrawal. It states that in recently accepting MISO's tariff provisions regarding multi-value projects, the Commission specifically found just and reasonable tariff provisions that authorize allocating to a withdrawing transmission owner the cost of a multi-value project approved before the withdrawal, although the associated facility will be located only in a MISO state.

705. Vermont Agencies note that while Order No. 1000 states that it will not authorize the allocation of costs of facilities located in one region to entities located in another region, because Order No. 1000 does not define ''region'' it could be read to claim authority to force market participants into a region where they will be subject to cost allocation plans agreed upon by the participants in that region.[835]

706. Finally, North Carolina Agencies state that while the Commission approves Principle 4, the Commission also states that if there are benefits of a new transmission project to a public or non-public utility within a region that has no transmission arrangement with the entity building the project, costs can still be allocated to that utility if it is found to benefit from the project. According to North Carolina Agencies, the Commission has committed error by not recognizing this apparent contradiction in the foregoing statements, as well as by stating that the costs of new transmission projects may be allocated involuntarily to those that lack any sort of connection to the transmission project in question.

c. Commission Determination

707. We affirm Regional and Interregional Cost Allocation Principle 4. Accordingly, we deny the arguments of those petitioners that ask us to expand the scope of Cost Allocation Principle 4 to permit a transmission planning region where a new transmission facility is located to allocate costs of the facility unilaterally to a neighboring region that benefits from it. Such arguments fail to take into account the relationship between the Commission's cost allocation reforms and the other reforms contained in Order No. 1000 and the need to balance a number of factors to ensure that the reforms achieve the goal of improved planning and cost allocation for transmission in interstate commerce.

708. In Order No. 1000, the Commission acknowledged that its approach may lead to some beneficiaries of transmission facilities escaping cost responsibility because they are not located in the same transmission planning region as the transmission facility. Nonetheless, the Commission found this approach to be appropriate since Order No. 1000 establishes a closer link between regional transmission planning and regional cost allocation, both of which involve the identification of beneficiaries. In light of that closer link, the Commission found that allowing one region to allocate costs unilaterally to entities in another region would impose too heavy a burden on stakeholders to actively monitor transmission planning processes in numerous other regions, from which they could be identified as beneficiaries and be subject to cost allocation. The Commission noted that if it expected such participation, the resulting regional transmission planning processes could amount to interconnectionwide transmission planning with corresponding cost allocation, albeit conducted in a highly inefficient manner. The Commission further explained that it is not requiring either interconnectionwide transmission planning or interconnectionwide cost allocation.[836]

709. Moreover, the discussion above highlights the importance that the ability to participate in the transmission planning and cost allocation process has for the Commission's transmission planning reforms. While the Commission concluded in Order No. 1000 that cost allocation is not dependent on a preexisting contractual relationship, we also think it is important that any entities that will be responsible for costs have an opportunity to participate in the process through which they will be allocated costs. This follows directly from the requirement of Order No. 890 that transmission planning be open and transparent. It also promotes a close link between transmission planning and cost allocation and helps to ensure fairness, which ultimately promotes successful transmission planning. Entities outside of a region may not be capable of being full participants in each and every region's transmission planning process in which they could potentially be allocated transmission costs. Unilateral allocation of costs to them thus could undermine rather than promote the linking of cost allocation and transmission planning.

710. Energy Future Coalition Group, Joint Petitioners, and AEP state that failing to revisit Cost Allocation Principle 4 does not address the Commission's concerns about free riders. North Carolina Agencies argue that the Commission's adoption of Cost Allocation Principle 4 contradicts the Commission's finding that costs can still be allocated to any entity that benefits from a new transmission facility without a transmission arrangement. As noted above, the Commission acknowledged in Order No. 1000 that its decision ''may lead to some beneficiaries of transmission facilities escaping cost responsibility because they are not located in the same transmission planning region as the transmission facility.'' [837] However, the Commission's cost allocation reforms represent a significant advance over current practices, and it is important to balance the possibility that some beneficiaries could escape cost responsibility against the larger goal of linking cost allocation with the transmission planning process for the purpose of improving that process. Additionally, as noted in our discussion of the need for the Commission's reforms, transmission planning is more likely to succeed if it is understood in advance how the costs of planned facilities will be allocated. While a preexisting contract is not necessary to establish a cost allocation, we believe that an ability to participate in the process in which costs are allocated is important as it promotes the improved transmission planning that Order No. 1000 seeks to achieve. The Commission acknowledged in Order No. 1000 that some beneficiaries could escape cost responsibility as a result of the decision not to allow costs to be allocated outside the region in which a transmission facility is located, but the implementation of any policy often requires one to balance a number of considerations, which we believe Cost Allocation Principle 4 does appropriately.

711. For these same reasons, we decline to adopt the suggestions made by those petitioners that attempt to address the burden on stakeholders to participate in several transmission planning regions, by for example, limiting extraregional cost allocation to higher voltage facilities or by requiring that costs be allocated only to regions adjacent to the one in which a transmission facility is located. While

joint operating agreement between PJM and MISO meet the requirements of the Final Rule for interregional transmission coordination without the need to justify the process in a compliance filing.

[835] Vermont Agencies at 9.

[836] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 660.

[837] *Id.*

we agree that these suggestions might mitigate the burden on some stakeholders, we nevertheless are not convinced that they are sufficient to ensure that the Commission is not through this rulemaking proceeding effectively requiring interconnectionwide transmission planning. In any event, nothing in Order No. 1000 would prohibit regions from voluntarily agreeing to bear the costs for transmission facilities located in neighboring regions and from which they receive a benefit. Doing so is not inconsistent with Cost Allocation Principle 4.[838]

712. We further disagree with petitioners that this determination will result in arbitrary drawing of regional boundaries to avoid cost allocation. In Order No. 890, the Commission determined that ''the scope of a transmission planning region should be governed by the integrated nature of the regional power grid and the particular reliability and resource issues affecting individual regions.'' [839] Consistent with that guidance, regions already have defined themselves for purposes of transmission planning. The Commission appreciates that these regional boundaries may change in response to Order No. 1000, but any such changes will be subject to Commission review on compliance to ensure that they continue to be appropriate. In response to Vermont Agencies' concerns about entities being forced into regions against their will, we note that in Order No. 1000, the Commission found that a transmission planning region ''is one in which public utility transmission providers, in consultation with stakeholders and affected states, *have agreed to participate* in for purposes of regional transmission planning and development of a single regional transmission plan.'' [840]

713. We agree with AEP that there can be cases where a project can have similar transmission flow impacts whether it is configured regionally or interregionally. However, we conclude that the regional and interregional transmission planning and coordination requirements of Order No. 1000 provide sufficient opportunities for analyzing the potential benefits of new transmission facilities, whether regional or interregional in configuration.

714. In response to MISO, we clarify that Cost Allocation Principle 4 does not preclude an RTO from allocating to a withdrawing RTO member the cost of eligible transmission upgrades located solely in the RTO and approved before the withdrawal pursuant to a Commission-approved RTO agreement.

[838] *Id.* PP 658–59.

[839] *Id.* P 160 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 527).

[840] *Id.* P 160 (emphasis added).

6. Whether To Establish Other Cost Allocation Principles

a. Final Rule

715. In Order No. 1000, the Commission stated that it did not believe that any additional cost allocation principles were necessary at that time.[841]

b. Requests for Rehearing

716. ELCON, AF&PA, and the Associated Industrial Groups argue that Order No. 1000 should address whether the costs of new transmission occasioned by low capacity factor resources should be allocated on a capacity basis. They assert that the Commission devoted no substantive consideration to this issue, and deferred it to the regional transmission planning processes. ELCON, AF&PA, and the Associated Industrial Groups assert that FERC provided no explanation for why this issue is better addressed by regional planning agencies. For example, they argue that allocating the fixed costs of transmission facilities intended to transmit wind energy to load centers on a volumetric basis inappropriately subsidies wind energy, which is inconsistent with resource neutrality and economically efficient resource allocation. Moreover, ELCON, AF&PA, and the Associated Industrial Groups argue that allocating these costs on any basis other than a capacity basis would unfairly penalize and significantly increase costs for those customers that have invested in operational changes to minimize consumption during system peak periods.

c. Commission Determination

717. We disagree with ELCON, AF&PA, and the Associated Industrial Groups' assertion that the Commission dismissed their proposal for new principles that would address cost allocation on a capacity basis without explanation. In Order No. 1000, the Commission declined to adopt additional principles proposed by commenters because the Commission believed that to do so would limit the flexibility provided to public utility transmission providers in proposing the appropriate cost allocation method or methods for their transmission planning region or pair of transmission planning regions.[842] We continue to believe this to be the case, and we therefore affirm the Commission's decision on this issue.

[841] *Id.* P 705.

[842] *Id.*

E. Application of Cost Allocation Principles

1. Participant Funding

a. Final Rule

718. In Order No. 1000, the Commission found that participant funding is permitted, but not as a regional or interregional cost allocation method.[843] The Commission explained that if proposed as a regional or interregional cost allocation method, participant funding would not comply with the regional or interregional cost allocation principles adopted in Order No. 1000.[844] The Commission explained, however, that these principles do not in any way foreclose the opportunity for a transmission developer, a group of transmission developers, or one or more individual transmission customers to voluntarily assume the costs of a new transmission facility.[845]

b. Requests for Rehearing or Clarification

719. Several petitioners request rehearing or clarification of the Commission's finding that participant funding cannot be the regional or interregional cost allocation method.[846] Ad Hoc Coalition of Southeastern Utilities states that, as a matter of policy, new long-line transmission facilities that span utility service areas must be supported by ascertainable demand, and that the most economically sound way to determine what facilities should be built, and at what price, is for those entities that will use the facilities to pay for them. ELCON, AF&PA, and the Associated Industrial Groups argue that prohibiting participant funding as a regional or interregional cost allocation method creates a new free rider problem. According to them, participants who, from an economic perspective, should be funding transmission, and could do so most expeditiously, will now have an incentive not to do so, because the cost will be allocated to other more peripheral beneficiaries as part of the regional transmission planning process.

720. ELCON, AF&PA, and the Associated Industrial Groups argue that the Commission's explanation of why participant funding should be

[843] *Id.* P 723.

[844] *Id.*

[845] *Id.* P 724.

[846] *See, e.g.,* Illinois Commerce Commission; ELCON, AF&PA, and the Associated Industrial Groups; Arizona Cooperative; Ad Hoc Coalition of Southeastern Utilities; and Southern Companies.

prohibited is both arbitrary and inconsistent when compared to determinations made by the Commission in Order No. 1000 concerning other cost allocation approaches. For instance, they state that the Commission was willing to leave the decision of whether postage stamp rate allocation is an appropriate cost allocation method to regional planning entities. ELCON, AF&PA, and the Associated Industrial Groups argue that Order No. 1000 subjects the two different cost allocation methods to widely divergent standards of scrutiny with no explanation as to why such differential treatment would be appropriate. They also seek clarification that Order No. 1000 allows participant funding to be used as the default for certain types of projects on a category basis where participant funding best matches cost causation principles.

721. Arizona Cooperatives and Southwest Transmission are concerned that Order No. 1000 does not recognize the benefits of participant funding. For instance, Arizona Cooperatives and Southwest Transmission state that under participant funding, the cost of associated transmission is bundled with generation. If the bundled price is excessive, then the project does not attract customers and an unworthy investment is avoided.

722. Southern Companies argue that the Commission's treatment of participant funding in Order No. 1000 is overly vague and unexplained. They state that the Commission should refine its guidance on rehearing to define ''participant funding'' more narrowly and in terms of the issue that Order No. 1000 seeks to address, rather than categorically excluding it. Southern Companies state the Commission should clarify that participant funding is only impermissible as a cost allocation method if there are identified beneficiaries and those beneficiaries would receive non-trivial, direct benefits and would be expected to participate in the facilities as a transmission customer or co-owner but for others valuing the new transmission facility more and agreeing to go ahead and support the project financially.

723. Southern Companies repeats arguments made above that the Supreme Court held the FPA is premised on the concept of voluntary sale and purchase of jurisdictional services and the courts have uniformly applied cost causation principles only in the setting of relationships where privity exists. Therefore, it asserts that participant funding may well be the only cost allocation method or rate structure that is lawful for new regional and/or interregional transmission projects as envisioned by Order No. 1000. Southern Companies assert that without a privity relationship between the developer of a project and those expected to fund the project, there is no lawful basis upon which to impose a rate, and no assurance that any rate would be in connection with the provision of a jurisdictional service. Large Public Power Council and Ad Hoc Coalition of Southeastern Utilities also state that the Commission's rejection of participant funding confounds a basic precept of the FPA that a utility's ability to recover its costs rests on a contractual relationship with its customers.

724. Southern Companies assert participant funding is consistent with cost causation and represents a proven-way of getting the costs of such regional and/or interregional transmission facilities allocated, paid and constructed on a timely basis.[847] Southern Companies add that given the Commission's objective to foster more development, categorical *ex ante* exclusion of a cost allocation method that has a proven track record of success does not reflect reasoned decision making. Large Public Power Council also believes that the only economically sound way to determine what facilities should be built, and at what price, is to have those entities that will use the facilities pay for them.

725. On the other hand, Transmission Dependent Utility Systems commend the Commission's ruling that participant funding cannot be used as a regional or interregional cost allocation method. Transmission Dependent Utility Systems also request that the Commission reaffirm its long-held policy prohibiting ''and'' pricing.[848] Transmission Dependent Utility Systems assert the Commission should confirm that any limited use of participant funding in the future will be bound by the Commission's same long-standing precedent.[849]

c. Commission Determination

726. We affirm Order No. 1000's determination that participant funding is permitted, but not as a regional or interregional cost allocation method.[850] We therefore continue to believe that if proposed as a regional or interregional cost allocation method, participant funding will not comply with the regional or interregional cost allocation principles adopted above. We remain concerned that reliance on participant funding as a regional or interregional cost allocation method increases the incentive of any individual beneficiary to defer investment in the hopes that other beneficiaries will value a transmission project enough to fund its development. Because of this, it is likely that some transmission facilities identified in the regional transmission planning process as more efficient or cost-effective solutions would not be constructed in a timely manner or would not be constructed at all, adversely affecting ratepayers. Moreover, reliance on participant funding as a regional or interregional cost allocation method leaves a transmission developer with no opportunity to allocate costs to beneficiaries identified in the regional transmission planning process, even if the developer's transmission facility is identified as a more efficient or cost-effective solution and is selected in the regional transmission plan for purposes of cost allocation. In light of this prospect, a transmission developer may decline to propose such a transmission facility in the regional transmission planning process.

727. The Commission rejected participant funding as a regional or interregional cost allocation method because it does not comply with the regional or interregional cost allocation principles set forth in Order No. 1000. This is because participant funding by its nature does not assess transmission project benefits in regional or interregional terms. For this reason, it does not ensure that the allocation of costs will be roughly commensurate with benefits, since its focus is limited to transmission project participants rather than the regional or interregional impact of a transmission project. Many petitioners describe what they consider to be advantages of participant funding, but these descriptions and the arguments based on them do not show how participant funding satisfies the

[847] Southern Companies at 109 (citing Bryan K. Hill September 28, 2010 Affidavit at 31–32).

[848] Transmission Dependent Utility Systems at 31 (citing *Standardization of Generator Interconnection Agreements and Procedures,* Order No. 2003, FERC Stats. & Regs. ¶ 31,146, at P 694 n.111 (2003), *order on reh'g,* Order No. 2003–A, FERC Stats. & Regs. ¶ 31,160 (2004), *order on reh'g,* Order No. 2003–B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g,* Order No. 2003–C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub. nom. Nat'l Ass'n of Regulatory Utils. Comm'rs* v. *FERC,* 475 F.3d 1277 (D.C. Cir. 2007)).

[849] Transmission Dependent Utility Systems at 31 (citing *Inquiry Concerning the Comm'n's Transmission Pricing Policy for Transmission Services Provided by Pub. Utils. Under the Fed. Power Act,* 55 Fed. Reg. 55,031, FERC Stats. & Regs. ¶ 31,005, at 31,142–43 (1994), *clarified,* 71 FERC ¶ 61,195 (1995); *Am. Elec. Power Co.,* 67 FERC ¶ 61,168 (1994)); *see also Pennsylvania Elec. Co.* v. *FERC,* 11 F.3d 207 (D.C. Cir. 1993).

[850] *See* Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at PP 723–29.

specific requirements or policy goals of Order No. 1000.

728. However, as Order No. 1000 made clear, we are not finding that participant funding leads to improper results in all cases. For example, a transmission developer may propose a project to be selected in the regional transmission plan for purposes of regional cost allocation but fail to satisfy the transmission planning region's criteria for a transmission project selected in the regional transmission plan for purposes of cost allocation. Under such circumstances, the developer could either withdraw its transmission project or proceed to ''participant fund'' the transmission project on its own or jointly with others. In addition, it is possible that the developer of a facility selected in the regional transmission plan for purposes of cost allocation might decline to pursue regional cost allocation and, instead, rely on participant funding. Moreover, nothing in Order No. 1000 forecloses the opportunity for a transmission developer, a group of transmission developers, or one or more individual transmission customers to voluntarily assume the costs of a new transmission facility. Accordingly, Order No. 1000 does not prohibit or, as Southern Companies assert, ''categorically'' exclude the use of participant funding.

729. The Commission nowhere intended to suggest that participant funding has no place in the development of transmission infrastructure. As noted by Southern Companies, participant funding can result in timely construction of transmission facilities in many circumstances. Transmission developers who see particular advantages in participant funding remain free to use it on their own or jointly with others. This simply means that they would not be pursuing regional or interregional cost allocation. ELCON, AF&PA, and the Associated Industrial Groups do not explain what they mean by the use of participant funding ''as the default for certain types of projects,'' [851] and we are not persuaded that the type of transmission project involved affects the ability of participant funding to satisfy the cost allocation principles of Order No. 1000.

730. The Commission did not state in Order No. 1000 that entities who support participant funding must show that it is uniquely the cost allocation method that follows ''but for'' cost causation principles, as ELCON, AF&PA, and the Associated Industrial Groups contend. The Commission simply stated that entities who had argued that it was such a method had not demonstrated that this was the case and that, moreover, the contention was at odds with existing precedent on cost causation.[852]

731. Southern Companies maintain that participant funding means different things to different people and that the Commission should define it more narrowly for purposes of Order No. 1000. However, Southern Companies do not describe the different meanings of participant funding that they have in mind, and we therefore do not know what further refinements it believes would be in order.[853] The Commission stated in Order No. 1000 that ''[u]nder a participant funding approach to cost allocation, the costs of a transmission facility are allocated only to those entities that volunteer to bear those costs.'' [854] In addition, the Commission noted in Order No. 1000 that the Proposed Rule cited to a number of concrete examples of the participant funding approach.[855] We think that this provides sufficient guidance on the meaning of participant funding for purposes of Order No. 1000.

732. We disagree that precluding participant funding as a regional and interregional cost allocation method creates a new free rider problem by creating an incentive for what ELCON, AF&PA, and the Associated Industrial Groups describe as entities who should be funding a transmission project not to fund it in the hope of an allocation to additional beneficiaries. The primary goal of Order No. 1000's cost allocation principles is to ensure that costs of regional transmission facilities selected in a regional transmission plan for purposes of cost allocation are allocated to beneficiaries in the region roughly commensurate with the benefits that they receive. It is unlikely that entities which benefit from such transmission facilities would decline to fund them. Moreover, we disagree with the argument that preclusion of participant funding as a regional or interregional cost allocation method creates an incentive not to develop a transmission project. On the contrary, a transmission developer will have the option of using participant funding or submitting its transmission project for evaluation in the regional transmission planning process to be selected for regional or interregional cost allocation. If its transmission project is selected in the regional transmission plan for purposes of cost allocation, the transmission developer would be able to allocate costs to beneficiaries consistent with the relevant cost allocation method, an opportunity that not only encourages development but also promotes development of more efficient or cost-effective transmission solution to regional and interregional transmission needs.

733. We think that this point helps illuminate why participant funding does not constitute an appropriate regional or interregional cost allocation method. Entities that might develop a transmission project through participant funding remain free to do so. However, exclusive reliance on such an approach creates an incentive not to consider potential regional or interregional transmission needs. It thus is not a method that is tailored to promote better regional and interregional transmission planning.

734. We deny Southern Companies' request for clarification on the situations in which participant funding should be impermissible. Southern Companies asserts that participant funding should only be impermissible if there are identified beneficiaries and those beneficiaries would receive non-trivial, direct benefits and would be expected to participate in the facilities as a transmission customer or co-owner but for others valuing the new transmission facility more and agreeing to go ahead and support the project financially. The

[851] ELCON, AF&PA, and the Associated Industrial Groups at 16.

[852] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 726.

[853] Southern Companies only state that the Commission's ''categorical exclusion'' of participant funding had created a need to state specifically in Order No. 1000 (in response to Entergy) that prohibition of participant funding as a regional cost allocation mechanism ''is not intended to modify existing pro forma OATT transmission service mechanisms for individual transmission service requests or requests for interconnection service.'' Southern Companies at 106 (quoting Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 729). Southern Companies state that specifying this was important because long-term firm transmission service is a form of participant funding that addresses free rider issues, and this demonstrates the need for greater clarity on what the Commission is prohibiting. *Id.* However, Order No. 1000 does not create a ''categorical exclusion'' of participant funding, only an exclusion of the use of participant funding as a regional cost allocation method. We therefore do not see how the continued use of existing mechanisms for individual transmission service requests affects our conclusions on the use of participant funding for new transmission facilities selected in a regional transmission plan for purposes of cost allocation. As a result, we do not see the need for further refinements in the meaning of participant funding for purposes of Order No. 1000. We think that the two very different contexts at issue in Southern Companies' argument—firm transmission service requests and regional transmission planning—make such analogies inappropriate.

[854] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 486 n.375 (citing Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 128).

[855] *Id. See* Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 128.

focus of the cost allocation reforms of Order No. 1000 is on transmission projects that are selected in the regional transmission plan for purposes of cost allocation, not the circumstances under which voluntary use of participant funding is appropriate.

735. We disagree with ELCON, AF&PA, and the Associated Industrial Groups who see inconsistency in the Commission's willingness to allow consideration of postage stamp rates as a cost allocation method, but not participant funding. As we noted above, Order No. 1000 found that a postage stamp cost allocation method may be appropriate where all customers within a specified transmission planning region are found to benefit from the use or availability of a transmission facility or class or group of transmission facilities, especially if the distribution of benefits associated with a class or group of transmission facilities is likely to vary considerably over the long depreciation life of the transmission facilities amid changing power flows, fuel prices, population patterns, and local economic considerations.[856] Accordingly, unlike participant funding, if such a showing can be made, a postage stamp cost allocation would meet Cost Allocation Principle 1's requirement that costs be allocated roughly commensurate with benefits. Participant funding, on the other hand, is incapable of meeting the regional or interregional cost allocation principles set forth in Order No. 1000, because by its nature it is not a cost allocation method that accounts for potential regional or interregional benefits.

736. We clarify, in response to Transmission Dependent Utility System's request, that Order No. 1000 did not address or change the Commission's policy on ''and'' pricing.[857] Order No. 1000 applies only to transmission projects that are selected in the regional transmission planning process for purposes of cost allocation. Participant funding cannot be the regional or interregional cost allocation method under Order No. 1000. Therefore, if a project's costs are allocated under a participant funding method, by definition, it was not selected in the regional transmission planning process for purposes of cost allocation.[858]

737. Lastly, a number of petitioners argue that participant funding is the form of cost allocation that corresponds to what they assert is a requirement that cost allocation be premised on a contractual relationship. As we explained above,[859] we reject the interpretation of the FPA that petitioners have offered, specifically that the FPA requires a contractual relationship before rates can be assessed. Contracts do not define or limit the benefits that a transmission customer receives from the entire transmission grid, which the courts have recognized in finding that the customer relationship is to the transmission grid as a whole, rather than the dictates of contracts.[860] Therefore, petitioners' arguments that the Commission's finding that participant funding cannot be the regional or interregional cost allocation method are unfounded.

F. Other Cost Allocation Issues

1. Final Rule

738. In Order No. 1000, the Commission reiterated the approach it took in Order No. 890, requiring that generation, demand resources, and transmission be treated comparably in the regional transmission planning process.[861] Also, the Commission stated that while the consideration of non-transmission alternatives to transmission facilities may affect whether certain transmission facilities are in a regional transmission plan, the Commission concluded that the issue of cost recovery for non-transmission alternatives was beyond the scope of the cost allocation reforms adopted in Order No. 1000, which are limited to allocating the costs of new transmission facilities.[862]

2. Requests for Rehearing or Clarification

739. California State Water Project argues that on rehearing the Commission should require all public utilities to exempt sponsors of demand-based transmission alternatives from Order No. 1000's benefits-based cost allocation, as well as apply time-sensitive cost allocation. Specifically, it argues that customers investing in demand-based non-transmission alternatives and sponsors of demand-based transmission alternatives should not be subject to benefits-based cost allocation that in effect imposes discriminatory double billing for both the transmission alternative provided and for unused transmission automatically deemed to provide benefits. Moreover, it adds that the Commission has stated that customers' ability to modify their behavior in response to price signals benefits the entire grid and is among the best means of holding down costs and countering market power.[863]

740. California State Water Project also argues that the rule unduly discriminates against demand-based non-transmission alternatives as it stressed the need for clear cost allocation to promote transmission construction, yet declined to consider compensation and cost allocation for demand-based non-transmission alternatives. California State Water Project states that in the Energy Policy Act of 2005 Congress declared that the national policy of the United States is to promote demand response and to eliminate unnecessary barriers to demand response.[864] It also states that the Commission followed up on this policy in Order No. 719, stating that ''[a]ny reforms must ensure that demand response resources are treated on a basis comparable to other resources.'' [865] California State Water Project adds that under the FPA the Commission also must not permit undue discrimination against such resources. It notes that the Commission has applied this principle to avert undue discrimination against various kinds of resources, such as the measures to remedy undue discrimination against non-incumbent transmission developers in Order No. 1000.[866]

741. California State Water Project recommends that the Commission

[856] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 605.

[857] *Standardization of Generator Interconnection Agreements and Procedures,* Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003), *order on reh'g,* Order No. 2003–A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g,* Order No. 2003–B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g,* Order No. 2003–C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs* v. *FERC,* 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied,* 552 U.S. 1230 (2008).

[858] The Commission made clear in Order No. 1000 that transmission facilities that are selected in the regional transmission plan for purposes of cost allocation may not comprise all of the transmission facilities in the regional transmission plan, and therefore, participant funded facilities may be included in the regional transmission plan for other purposes. Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 63.

[859] *See* discussion *supra* at section 0.

[860] *See* discussion *supra* at section 0.

[861] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 779.

[862] The Commission also recognized that, in appropriate circumstances, alternative technologies may be eligible for treatment as transmission for ratemaking purposes. Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 779 & n.563.

[863] California State Water Project at 18 (quoting Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 41).

[864] California State Water Project at 9–10 (citing Energy Policy Act of 2005, Pub. L. 109–58, § 1252(f), 119 Stat. 594 (2005)).

[865] California State Water Project at 10 (quoting Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 14).

[866] California State Water Project at 11 (citing Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,669; Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 229).

incorporate benchmarks or metrics to support periodic evaluation of its success or failure in achieving nondiscriminatory promotion of both physical transmission upgrades and non-transmission alternatives. It argues that incorporating such benchmarks will ensure that the Commission and all concerned undertake appropriate improvements on a timely basis.

742. Transmission Dependent Utility Systems point out that in their comments during the Order No. 1000 proceeding, they requested that the Commission align local, regional and interregional planning and cost allocation processes and methods with formula rate protocols because those who pay the costs of needed new transmission infrastructure should not learn about projects for the first time in formula rate updates. In particular, Transmission Dependent Utility Systems argue that to the extent project upgrade costs are not discussed in the planning processes with stakeholders, a separate FPA section 205 filing must be made for recovery of these costs. It argues that most public utility transmission providers have incentive rates and that the formula rate annual update process provides only limited opportunity to review and challenge costs included in the formula rate update filing. Transmission Dependent Utility Systems argue that their requested link between formula rate cost recovery and the local and regional planning and interregional coordination processes is within the scope of issues raised in this proceeding because it is a safeguard needed to ensure that load-serving customers, which pay for the costs of transmission upgrades, have a meaningful role in the development of regional and interregional projects and the allocation of the costs of those projects. Transmission Dependent Utility Systems further assert that Order No. 1000 failed to address this issue in a manner that comports with reasoned decision-making.[867]

743. Dayton Power and Light requests clarification that the Commission will issue a separate order on remand from the Seventh Circuit on Opinion No. 494 [868] in the near future that will specify a cost allocation mechanism for new high voltage facilities that complies with the Order No. 1000 principles.[869] Dayton Power and Light states that failing to issue an order on remand would lead to renewed litigation a year from now to address the same issues using substantially the same evidence that is already before the Commission for decision and waste the resources of PJM members, PJM, and the Commission and its staff.

744. Dayton Power and Light urges the Commission to state explicitly that the use of the Distribution Factor analysis complies with the Order No. 1000 cost allocation principles. In support, Dayton Power and Light states that PJM has used distribution factor analysis to allocate the costs of new PJM facilities operating at less than 500 kV without question or challenge.

3. Commission Determination

745. We deny California State Water Project's arguments and affirm Order No. 1000's determination that cost allocation for non-transmission alternatives is beyond the scope of this proceeding, which is limited to allocating the costs of new transmission facilities. In response to California State Water Project's suggestions regarding time-sensitive rates and the establishment of benchmarks, we affirm Order No. 1000, and therefore, will not establish minimum requirements governing which non-transmission alternatives should be considered or the appropriate metrics to measure non-transmission alternatives against transmission alternatives. We continue to believe that those considerations are best managed among the stakeholders and the public utility transmission providers participating in the regional transmission planning process.[870]

746. We deny Transmission Dependent Utility Systems' request that we address a link between formula rates and cost allocation as beyond the scope of this proceeding. As we note above, and as we found in Order No. 1000, we are not addressing cost recovery issues here.[871] In any event, we disagree with Transmission Dependent Utility Systems' premise that those who pay for project upgrade costs that are selected in a regional transmission plan for purposes of cost allocation under the provisions of Order No. 1000 may learn about these costs for the first time when flowed through a formula rate, when there would be only a limited opportunity to review the costs.[872] As is clear in Order No. 1000, any entity can participate in the regional transmission planning process and costs will be allocated only for those regional and interregional transmission facilities that have been selected in the regional transmission plan for purposes of cost allocation.[873] Therefore, Transmission Dependent Utility Systems will have a meaningful opportunity to participate in the development of regional and interregional transmission projects and the allocation of the costs of those transmission projects, whether or not these are incorporated into formula rates, through their ability to participate in the regional transmission planning process. Additionally, as noted above, in identifying the benefits and beneficiaries for a new transmission facility, the regional transmission planning process must provide entities who will receive regional or interregional cost allocation an understanding of the identified benefits on which the cost allocation is based, all of which would occur prior to the recovery of such costs through a formula rate.

747. In response to Dayton Power and Light's request that the Commission find that the use of the distribution factor analysis complies with Order No. 1000 cost allocation principles, we reiterate what the Commission said in Order No. 1000 in response to commenters making similar arguments. We decline to prejudge whether any existing cost allocation method complies with the requirements of Order No. 1000. To the extent that Dayton Power and Light believes that to be the case in its transmission planning region, it can take such a position during the development of compliance proposals and during Commission review of compliance filings.[874] Last, with respect to the timing concerns Dayton Power and Light describes regarding the relationship between our order on remand from the U.S. Court of Appeals for the Seventh Circuit on Opinion No. 494 and the development of an Order No. 1000-compliant cost allocation method in PJM, the Commission has since issued an order in the Opinion No. 494 proceeding.[875]

V. Compliance and Reciprocity

A. Compliance

1. Final Rule

748. The Commission required that each public utility transmission provider must submit a compliance filing within twelve months of the

[867] Transmission Dependent Utility Systems at 31 (citing *K N Energy Inc.* v. *FERC,* 968 F.2d 1295, 1303)).

[868] *PJM Interconnection, L.L.C.,* 130 FERC ¶ 61,052 (2010).

[869] Dayton Power and Light at 2, 4 (citing *Illinois Commerce Commission* v. *FERC,* 576 F.3d 470).

[870] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 155.

[871] *Id.* P 563.

[872] In any event, we note that when ratepayers learn of other formula costs is outside the scope of this proceeding.

[873] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 503.

[874] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 565.

[875] *PJM Interconnection, L.L.C.,* 138 FERC ¶ 61,230 (2012).

effective date of Order No. 1000 revising its OATT or other document(s) subject to the Commission's jurisdiction as necessary to demonstrate that it meets the local and regional transmission planning and cost allocation requirements set forth in Order No. 1000. The Commission also required each public utility transmission provider to submit a compliance filing within eighteen months of the effective date of Order No. 1000 revising its OATT or other document(s) subject to the Commission's jurisdiction as necessary to demonstrate that it meets the requirements set forth therein with respect to interregional transmission coordination procedures and an interregional cost allocation method or methods.[876]

2. Requests for Rehearing or Clarification

749. Duke requests that the Commission rule on requests for clarification as soon as possible before issuance of an Order No. 1000 rehearing order so that stakeholders' compliance efforts are not interrupted or entirely disrupted. MISO requests that the Commission clarify that RTOs and ISOs are not required to make any changes to their tariffs or processes in connection with the participation of non-jurisdictional entities in regional or interregional planning and cost allocation processes. According to MISO, requiring the development of a regional plan and cost allocation process with an entity that has no such corresponding mandate is unreasonable, and it may not be possible to comply with such a requirement because compliance would depend entirely on the desire of such non-jurisdictional entities to coordinate. MISO states that at most, the Commission should require that Commission-jurisdictional entities engage in a good faith effort at regional coordination, planning, and cost allocation with non-jurisdictional entities.

750. NextEra seeks clarification that generator tie line owners that have OATTs on file can seek waiver of compliance with Order No. 1000 requirements, as the Commission has previously found that such lines are not integrated with the regional transmission grid for ratemaking purposes. It suggests that there may be confusion as to whether such tie line owners can seek waiver because of use of the word ''and'' rather than ''or'' when Order No. 1000 states that entities must seek waivers of Order Nos. 888, 889, *and* 890. NextEra contends that if the Commission intended to mean ''or,'' then the vast majority of tie line owners would not be subject to Order No. 1000.[877] It also urges the Commission to adopt a broad-based waiver that focuses on the nature of a radial line, which it argues would be consistent with the intent of the transmission planning process. NextEra argues that the fact that such tie lines are not integrated in the transmission grid should not be ignored. It states that the nature of a radial line does not change simply because one tie line owner may provide interconnection and transmission service to affiliates and have waivers from Order Nos. 888, 889, and 890 while another may provide the same service under an OATT to non-affiliates. NextEra states further that no generation tie lines should be required to participate in the regional transmission planning process unless they voluntarily choose to do so.[878]

3. Commission Determination

751. In response to Duke, we believe that addressing the requests for clarification of Order No. 1000 in this order is appropriate. Many of the requests for clarification are linked with requests for rehearing and are thus best addressed in the same order. Moreover, the Commission considered the need for providing timely clarifications in issuing this order now, and we believe that its issuance now allows stakeholders adequate time to address these clarifications in their compliance processes.

752. We clarify for MISO that a public utility transmission provider will not be deemed out of compliance with Order No. 1000 if it demonstrates that it made a good faith effort, but was ultimately unable, to reach resolution with neighboring non-public utility transmission providers on a regional transmission planning process, interregional transmission coordination procedures, or a regional or interregional cost allocation method.

753. In response to NextEra, we clarify that Order No. 1000's determination that it ''applies to public utilities that own, control or operate interstate transmission facilities other than those that have received waiver of the obligation to comply with Order Nos. 888, 889, and 890''[879] was meant to provide assurance to those entities that have existing waivers of those three rules that they would not also have to seek waiver of Order No. 1000 in order to obtain waiver from it. This is consistent with the approach the Commission took to waivers in Order No. 890.[880] This determination, however, was not meant to affect the ability of an entity that does not have a waiver to seek one. The Commission will entertain requests for waiver of Order No. 1000 on a case-by-case basis from any entity, including a generation tie line owner, that believes it meets the criteria for such waiver, which the Commission made clear in Order No. 1000 remains unchanged from that used to evaluate requests for waiver under Order Nos. 888, 889, and 890.[881]

B. Reciprocity

1. Final Rule

754. In Order No. 1000, the Commission found that to maintain a safe harbor tariff, a non-public utility transmission provider must ensure that the provisions of that tariff substantially conform, or are superior, to the *pro forma* OATT as it has been revised by Order No. 1000.[882] The Commission stated that it was encouraged that, based on the efforts that followed Order No. 890, both public utility and non-public utility transmission providers collaborate in a number of regional transmission planning processes.[883] Therefore, the Commission did not believe it was necessary to invoke its authority under FPA section 211A, which gives it authority to require non-public utility transmission providers to provide transmission services on a comparable and not unduly discriminatory or preferential basis.[884] However, the Commission stated that if it finds on the appropriate record that non-public utility transmission providers are not participating in the transmission planning and cost allocation processes required by Order

[876] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 792.

[877] NextEra at 16.

[878] NextEra at 17 (citing *Southern Cal. Edison Co.,* 117 FERC ¶ 61,103 (2006); *Mansfield Mun. Elec. Dept.* v. *New England Power Co.,* 97 FERC ¶ 61,134 (2001)).

[879] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 832.

[880] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at n.105 (''The Commission clarifies that existing waivers of the obligation to file an OATT or otherwise offer open access transmission service in accordance with Order No. 888 shall remain in place. The reforms to the *pro forma* OATT adopted in this Final Rule therefore do not apply to transmission providers with such waivers, although we expect those transmission providers to participate in the regional planning processes in place in their regions, as discussed in more detail in section V.B. Whether an existing waiver of OATT requirements should be revoked will be considered on a case-by-case basis in light of the circumstances surrounding the particular transmission provider.''); *see also* Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 at P 36.

[881] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 832.

[882] *Id.* P 815.

[883] *Id.*

[884] *Id.*

No. 1000, the Commission may exercise its authority under FPA section 211A on a case-by-case basis.[885] The Commission also emphasized that it is not modifying the scope of the reciprocity provision as established in Order No. 890.[886] However, the Commission noted that it expects all public and non-public utility transmission providers in an existing regional transmission planning process comprised of both public and non-public utility transmission providers to participate in the transmission planning and cost allocation processes set forth in Order No. 1000. The Commission also noted that those non-public utility transmission providers that take advantage of open access under an OATT, including the OATT's new provisions for improved transmission planning and cost allocation, should be expected to follow the same requirements as public utility transmission providers.[887]

2. Requests for Rehearing or Clarification

755. Petitioners request rehearing of Order No. 1000's reciprocity requirement, arguing that the Commission is changing the scope of the principle of reciprocity under Order Nos. 888 and 890. For example, Large Public Power Council states that reciprocity as initially conceived in Order No. 888 was a matter of fundamental fairness. It states that this concept was clarified in Order No. 2004–A, where the Commission found that service provided by a non-public utility transmission provider did not have to be identical to the service provided by an investor-owned utility, only comparable to the service the non-public utility would receive for its own purposes. Large Public Power Council explains that Order No. 1000 appears to hold that a non-public utility's obligation to provide reciprocal service outside a safe harbor tariff includes an obligation to participate in the planning and cost allocation processes implemented pursuant to Order No. 1000. Large Public Power Council states that including these planning and cost allocation obligations within a non-public utility's reciprocity obligations would modify the scope of reciprocity, and thus requests that the Commission clarify whether this is its intention.

756. Likewise, National Rural Electric Coops state that it appears that the Commission misstated the reciprocity requirement in Order No. 1000 when it stated in paragraph 819 that ''the non-public utility transmission provider that owns, controls or operates transmission facilities *must* provide comparable transmission service that it is capable of providing on its own system.'' [888] They assert that under the Commission's existing reciprocity requirement, a non-public utility transmission provider is not obligated to provide such service, because a public utility transmission provider is not obligated to refuse to provide service if a non-public utility transmission provider does not reciprocate. Rather, they point out that there are three alternatives available to non-public utilities to meet the reciprocity requirement, including obtaining a waiver from, or entering into a bilateral agreement with, the public utility transmission provider from which the non-public utility seeks service, and that providing service under a safe harbor tariff is only one alternative. National Rural Electric Coops state that only a few non-public utilities have Commission-approved reciprocity tariffs and significant disputes could arise from the unintentional language in Order No. 1000. They state that clarification would help to minimize controversies over the scope of non-public utilities' obligations with respect to regional planning and cost allocation, and would be consistent with the Commission's statement that it is not proposing any changes to the reciprocity provision of the *pro forma* OATT or any other document.

757. Sacramento Municipal Utility District also states that by asserting that all non-public utilities must abide by Order No. 1000's transmission planning and cost allocation provisions if they take open access service, the Commission both: (1) Eviscerates the waiver option expressly contemplated under Order Nos. 888 and 890 and (2) creates an automatic trigger directly at variance with the principle that non-public utilities must reciprocate if asked to do so. Sacramento Municipal Utility District points out that Order Nos. 888 and 890 unambiguously require safe harbor candidates to adopt tariffs that match or exceed the terms of the pro forma OATT. It argues, however, that the Commission's interpretation in Order No. 1000 that non-public utilities without safe harbor tariffs that take service under open access tariffs also are automatically bound to follow the transmission planning and cost allocation provisions of Order No. 1000 improperly conflates the safe harbor tariff provisions found in Order Nos. 888 and 890 since markedly different reciprocity requirements apply when a non-public utility does not employ a safe harbor tariff.

758. Sacramento Municipal Utility District further argues that the Commission's longstanding policy has been that reciprocity under Order Nos. 888 and 890 only obligates the non-public utility to provide transmission service to individual public utility transmission providers requesting reciprocity as a condition of obtaining their transmission service if a non-public utility has not sought a ''safe-harbor'' tariff.[889] Sacramento Municipal Utility District argues that the actual provisions of Order Nos. 888 and 890 make clear that a reciprocity obligation is not automatic, is purely bilateral and applies only to the transmission provider that asks the non-public utility to reciprocate.[890] Thus, Sacramento Municipal Utility District states that the Commission's determination that the act of taking service from a public utility with a regional cost allocation plan in its open access tariff automatically triggers the non-public utility's reciprocity obligation under Order Nos. 888 and 890 constitutes an arbitrary and unexplained departure from the policies established in those orders.[891]

759. Bonneville Power further argues that the Commission is inappropriately attempting to regulate Bonneville Power and other non-public utility transmission providers under section 206 of the FPA. In support, Bonneville Power asserts that the Commission's action is more extreme than its attempt to impose refund liability on non-public utilities in, for example, *BPA* v. *FERC*.[892] Bonneville Power contends that in that case, the court held the Commission lacked refund authority over non-public utilities that participated in a power market established by a public utility. Bonneville Power argues that the Commission is similarly imposing cost responsibility on non-public utilities under section 206 absent statutory authority to do so. Bonneville Power contends that if the Commission denies

[885] *Id.*

[886] *Id.* P 816.

[887] *Id.* P 818.

[888] National Rural Electric Coops at 5–6 (quoting Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 819).

[889] Sacramento Municipal Utility District at 3.

[890] Sacramento Municipal Utility District at 18 (citing *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Serv. By Pub. Utils; Recovery of Stranded Costs by Pub. Utils. And Transmitting Utils.*, Order No. 888–A, FERC Stats. & Regs. ¶ 31,048, at P 30, 180–81(1997)).

[891] Sacramento Municipal Utility District at 3 (citing *FCC* v. *Fox Television Stations,* Inc., 129 S. Ct. 1800, 1811 (2009); *Greater Boston Television Corp.* v. *FCC,* 444 F.2d 841, 952 (D.C. Cir. 1970), *cert. denied,* 403 U.S. 923 (1971)).

[892] Bonneville Power at 17 (citing *BPA* v. *FERC,* 422 F.3d 908, 921 (9th Cir. 2005)).

clarification that the regional planning process determination would not be binding on Bonneville Power and that instead, it and transmission developers could use the cost allocation analysis as input to their negotiations and other required statutory processes, then the Commission is directly regulating Bonneville Power by not allowing Bonneville Power to follow its own statutory authority in implementing cost allocation in place of the Commission's policy adopted under section 206, which the Commission cannot do.

760. Sacramento Municipal Utility District argues that the Commission lacks the authority to mandate regional transmission planning and therefore it cannot attach an obligation to accept the cost allocation agreement negotiated under a regional transmission planning process that the non-public utility was not mandated to join. Sacramento Municipal Utility District therefore contends that since non-public utilities under section 201(f) are not subject to section 205 and 206, they cannot be required as a condition of reciprocity to accept cost allocation agreements that the Commission has no authority to impose even on public utilities.

761. Sacramento Municipal Utility District states that when a non-public utility takes service from a jurisdictional public utility, it will pay a tariff rate approved by the Commission, and a reciprocity provision is simply unnecessary to ensure proper cost recovery. Sacramento Municipal Utility District argues that if the non-public utility takes no service from a transmission provider that has constructed a new facility approved by a regional transmission planning body, and the costs of that facility are not properly included in the rates of other transmission providers from whom the non-public utility does take service, the reciprocity provision should be completely inapplicable.

762. Moreover, Sacramento Municipal Utility District argues that cost allocation is not a transmission service so that a non-public utility requesting only transmission service can be deemed to have reciprocated only by participating in regional cost allocation. Similarly, Bonneville Power contends that the Commission should not condition a non-jurisdictional transmitting utility's ability to receive transmission service from a public utility on the non-jurisdictional utility's inclusion of Order No. 1000's planning and cost allocation reforms in its own tariff because the provisions of Order No. 1000 go well beyond the basic provision of transmission service and are not the type of provisions that reasonably fall within the reciprocity construct.

763. Edison Electric Institute seeks clarification that section 6 of the OATT, which codifies the reciprocity requirement, enables a public utility to refuse transmission service to unregulated transmitting utilities that refuse to participate in regional transmission planning and cost allocation processes. Furthermore, Edison Electric Institute seeks clarification that, to satisfy the reciprocity requirements, unregulated transmitting utilities must fulfill each of the compliance requirements imposed on public utilities. If unregulated transmitting utilities do not, then Edison Electric Institute argues that the Commission should clarify that they have failed to offer the ''comparable'' service required under section 6 of the OATT.

764. Large Public Power Council seeks clarification that the Commission did not intend that it would enforce reciprocity tariff provisions itself. Large Public Power Council states that if the Commission does intend to enforce the reciprocity provisions itself, Large Public Power Council seeks rehearing. Large Public Power Council argues that to date, the Commission has not intimated that it has authority to enforce these provisions with respect to a non-public utility, which is consistent with case law finding that a non-public utility's involvement in Commission-jurisdictional service does not authorize the Commission to regulate the non-public utility.

765. Other petitioners argue that the Commission does not have authority under section 211A to compel a non-public utility transmission provider to participate in planning or pay for regional or interregional transmission projects.[893] For instance, Large Public Power Council asserts that section 211A makes it plain that the Commission's authority is limited to compelling a non-public utility to provide transmission service at rates and on terms and conditions that are essentially inward looking. As such, Large Public Power Council contends that the Commission cannot redefine the terms under which service is to be provided under section 211A in a manner that would give the Commission broader authority than that given by Congress. Accordingly, it states that the Commission does not have the authority to compel non-public utilities to contribute to new regional or interregional cost allocation mechanisms, or to operate according to Commission-approved transmission plans directing the level and nature of transmission investment.

766. Sacramento Municipal Utility District asserts that section 211A of the FPA makes clear that the comparability the Commission is empowered to enforce is comparability to the transmission services the non-public utility provides to itself, and that if a non-public utility chooses not to participate in a regional cost allocation process as part of its service to itself, it cannot be compelled to participate or to accept a regional cost allocation plan under section 211A. Bonneville Power contends that the Commission is inappropriately attempting to indirectly regulate non-public utility transmission providers by suggesting that it will use section 211A to obtain their compliance with mandatory cost allocation. Sacramento Municipal Utility District and Bonneville Power, therefore, argue that the Commission should remove its statement that it will use section 211A against non-public utility transmission providers to obtain compliance with Order No. 1000. Sacramento Municipal Utility District alternatively urges the Commission to clarify that its interpretation is not binding and is without prejudice to the rights of non-public utilities to challenge such an interpretation in any actual case in which the Commission invokes the authority to mandate non-public utility participation in regional planning and cost allocation.

767. On the other hand, Edison Electric Institute argues that the Commission erred by relying on non-public utility transmission providers to voluntarily participate in regional transmission planning and cost allocation processes.[894] Edison Electric Institute argues that the Commission should have exercised its authority under section 211A to ensure that unregulated transmitting utilities comply with the transmission planning and regional cost allocation provisions on the same terms and conditions as jurisdictional public utilities. Edison Electric Institute also asserts that the Commission has not demonstrated or otherwise explained why mandatory action is required in the case of public utility but is not required for non-public utility transmission providers. Edison Electric Institute asserts that both sets of utilities own transmission facilities, provide transmission service to customers, and may currently

[893] *See, e.g.,* Large Public Power Council; Sacramento Municipal Utility District; and Bonneville Power.

[894] Edison Electric Institute at 26 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 815).

participate in regional transmission planning processes.

768. Edison Electric Institute asserts that the Commission is authorized through section 211A to act ''by rule'' to require unregulated transmitting utilities to remedy discriminatory transmission rates and practices.[895] Edison Electric Institute states that the Commission has recognized that section 211A allows it to require an unregulated transmitting utility to provide transmission services on a comparable and not unduly discriminatory basis. Edison Electric Institute further states that section 211A contains the same ''unduly discriminatory or preferential'' standard found in section 206. Thus, Edison Electric Institute concludes that FPA section 211A, along with section 206, vests the Commission with the duty to eliminate undue discrimination and to ensure open access to transmission across the entire interstate grid.

769. Edison Electric Institute argues that the Commission's decision to rely on voluntary compliance is ill-founded and inadequate because there is no indication that non-jurisdictional utilities will voluntarily comply. It also argues that since Order No. 888, non-jurisdictional utilities have not fully embraced voluntary compliance with the Commission's open access reforms. Furthermore, Edison Electric Institute argues that allowing non-public utilities to participate voluntarily injects uncertainty in transmission planning and cost allocation, especially in areas that are predominately served by unregulated entities. Edison Electric Institute asserts that participants in regional transmission planning and cost allocation processes should not have to wait to know whether an unregulated transmitting utility, and potential beneficiary of a transmission project, is going to be subject to regional cost allocation. Edison Electric Institute adds that it also is unclear if, when, and how the Commission will exercise its authority under section 211A. Edison Electric Institute asserts that the lack of certainty, layered on to the short period for compliance, will undermine confidence in the planning and regional cost allocation processes and hinder their development.

770. Edison Electric Institute requests that the Commission clarify and strengthen the obligations of unregulated transmitting utilities to facilitate full compliance with regional planning and cost allocation provisions, and make clear when and how it will act on a case-by-case basis under section 211A. In addition, Edison Electric Institute states that the Commission has the authority to direct unregulated transmitting utilities to comply with the requirements in Order No. 1000, whether it learns of non-compliance through a complaint or on its own motion. Edison Electric Institute argues that failure by the Commission to act would be an abdication of its obligation to ensure non-discriminatory treatment in transmission service.

3. Commission Determination

771. In response to petitioners who are concerned that the Commission is modifying the scope of the reciprocity requirement under Order Nos. 888 and 890, we clarify that the reciprocity requirement remains unchanged. A non-public utility transmission provider may continue to satisfy the reciprocity condition in one of three ways. First, it may provide service under a tariff that has been approved by the Commission under the voluntary ''safe harbor'' provision of the *pro forma* OATT. A non-public utility transmission provider using this alternative submits a reciprocity tariff to the Commission seeking a declaratory order that the proposed reciprocity tariff substantially conforms to, or is superior to, the *pro forma* OATT. The non-public utility transmission provider then must offer service under its reciprocity tariff to any public utility transmission provider whose transmission service the non-public utility transmission provider seeks to use. Second, the non-public utility transmission provider may provide service to a public utility transmission provider under a bilateral agreement that satisfies its reciprocity obligation. Finally, the non-public utility transmission provider may seek a waiver of the reciprocity condition from the public utility transmission provider.[896]

772. We affirm the Commission's determination in Order No. 1000 that to maintain a reciprocity tariff under the voluntary ''safe harbor'' provision, a non-public utility transmission provider must ensure that the provisions of that tariff substantially conform, or are superior, to the *pro forma* OATT and its Attachment K as these have been revised by Order No. 1000.[897] As such, if a non-public utility transmission provider wishes to maintain its safe harbor tariff, it will need to ensure that it addresses Order No. 1000's transmission planning and cost allocation reforms, so that it continues to substantially conform, or be superior, to the *pro forma* OATT.

773. As we note above, the other two ways of satisfying the reciprocity requirement also remain intact. For example, a non-public utility transmission provider seeking service from a public utility transmission provider may seek to enter into a bilateral agreement with the public utility transmission provider that addresses that public utility transmission provider's desire for reciprocity. In such case, a public utility transmission provider may agree to provide service to a non-public utility transmission provider without requiring that non-public utility transmission provider to provide reciprocal service under terms and conditions that are necessarily substantially conforming with, or superior to, the *pro forma* OATT, which includes the transmission planning and cost allocation reforms in Order No. 1000. With respect to such bilateral agreements, the Commission in Order No. 888–A stated that it ''must leave these agreements to case-by-case determinations.'' [898] In doing so, the Commission stated that the terms and conditions that ''may be necessary for a non-public utility to provide reciprocal service to the public utility in a bilateral agreement is necessarily a fact-specific matter not susceptible to resolution in a generic rulemaking proceeding.'' [899] As such, we deny Edison Electric Institute's request for generic clarification that section 6 of the *pro forma* OATT, which codifies the reciprocity requirement, would allow a public utility transmission provider to refuse service to a non-public utility transmission provider that refused to enroll in the regional transmission planning and cost allocation processes. However, we note that in Order No. 888–A, the Commission also made clear that ''a public utility may refuse to provide open access transmission service to a non-public utility if its denial is based on a good faith assertion that the non-public utility has not met the Commission's reciprocity requirements.'' [900] While we will

[895] Edison Electric Institute at 27 (quoting 16 U.S.C. 824j–1(b)).

[896] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 799 & n.574 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 163 (citing Order No. 888–A, FERC Stats. & Regs. ¶ 31,048 at 30,285–86)).

[897] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 815 and Appendix C: *Pro Forma* Open Access Transmission Tariff.

[898] Order No. 888–A, FERC Stats. & Regs. ¶ 31,048 at 30,289.

[899] *Id.*

[900] *Id.* This approach is also consistent with Order No. 890 where the Commission stated that ''[u]nder the reciprocity provision in section 6 of the *pro forma* OATT, if a public utility seeks transmission service from a non-public utility to which it provides open access transmission service, the non-public utility that owns, controls, or operates

continue to address such matters on a case-by-case basis consistent with Order No. 888–A, we nevertheless note our finding in Order No. 1000 that those that ''take advantage of open access, including improved transmission planning and cost allocation, should be expected to follow the same requirements as public utility transmission providers.'' [901] Finally, a public utility transmission provider remains free to waive any reciprocity requirement for a non-public utility transmission provider that seeks service from it.

774. We further clarify in response to National Rural Electric Coops that, in the absence of a safe harbor tariff, a non-public utility transmission provider's obligation to a public utility transmission provider to provide a comparable transmission service that it is capable of providing on its own system begins when that public utility transmission provider requests comparable reciprocal service from the non-public utility transmission provider.[902] We also clarify for Large Public Power Council that the Commission did not intend that it would enforce reciprocity tariff provisions sua sponte, except insofar as the Commission permits a public utility transmission provider to refuse to offer open access transmission service to that non-public utility transmission provider, in accordance with Order No. 888.

775. Because the reciprocity provisions of Order Nos. 888, 890, and 1000 do not impose any requirement on non-public utility transmission providers, we reject Bonneville Power's and Sacramento Municipal Utility District's arguments that the Commission is attempting to regulate non-public utility transmission providers. As the Commission stated in Order No. 1000, non-public utility transmission providers are free to decide whether they will seek transmission service that is subject to the Commission's jurisdiction, and the Commission does not exercise jurisdiction over them when it determines the terms under which public utility transmission providers must provide that transmission service.[903] As such, the reciprocity provision of Order No. 1000 does not require non-public utility transmission providers to comply with the Order No. 1000 transmission planning and cost allocation reforms. In addition, as explained above in the discussion of our legal authority to implement Order No. 1000's transmission planning reforms, we disagree with Sacramento Municipal Utility District's contention that the Commission lacks the authority to mandate regional transmission planning for public utility transmission providers.[904]

776. In response to Sacramento Municipal Utility District's concern that a reciprocity provision is ''unnecessary to ensure proper cost recovery,'' [905] and Bonneville Power's and Sacramento Municipal Utility District's concerns that the transmission planning and cost allocation reforms should be outside the reciprocity construct, we disagree. Any non-public utility transmission provider that takes transmission service from a public utility transmission provider after implementation of Order No. 1000 is likely to benefit from the new OATT provisions of the public utility transmission providers in that region providing for improved regional transmission planning and for regional cost allocation commensurate with benefits for selected facilities, as provided in Order No. 1000. We therefore in Order No. 1000 applied the reciprocity provisions of Order Nos. 888 and 890 to provide that it is within the Commission's discretion to allow a public utility transmission provider to refuse to offer open access transmission service to any non-public utility transmission provider that does not provide comparable reciprocal transmission service insofar as it is capable of doing so, including regional planning and cost allocation. However, we reiterate a clarification made above that it is only when a non-public utility transmission provider actually makes the choice to become part of a transmission planning region by enrolling in that region that it would be subject to the regional and interregional cost allocation methods for that region.[906]

777. In response to Bonneville Power's and Sacramento Municipal Utility District's contention that certain provisions of Order No. 1000, such as those relating to cost allocation, go beyond the provision of transmission service and thus should not be incorporated in the Commission's reciprocity condition, we reiterate that both transmission planning and cost allocation are integral and essential components of the provision of transmission service. The transmission planning and cost allocation reforms adopted in Order No. 1000 are intended to facilitate the development of a robust transmission system capable of providing improved open access transmission service and to help ensure that transmission rates are just and reasonable and not unduly discriminatory or preferential.

778. We decline to address petitioners' arguments concerning the scope of our authority under FPA section 211A in this proceeding because the Commission did not act under FPA section 211A in Order No. 1000.[907] As the Commission stated in Order No. 1000, the success of the transmission planning process set forth therein will be enhanced if all transmission owners participate. The Commission further stated that non-public utility transmission providers will benefit greatly from the improved transmission planning and cost allocation processes required for public utility transmission providers because a well-planned grid is more reliable and provides more available, less congested paths for the transmission of electric power in interstate commerce.[908]

VI. Information Collection Statement

779. The Office of Management and Budget (OMB) requires that OMB approve certain information collection and data retention requirements imposed by agency rules.[909] Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of a rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

780. Previously, the Commission submitted to OMB the information collection requirements arising from Order No. 1000 and OMB approved those requirements. In this order, the Commission is making no substantive changes to those requirements, but has provided clarifications that require public utility transmission providers, and transmission developers, to collect additional information. Therefore, the Commission finds it necessary to make

transmission facilities must provide comparable transmission service that it is capable of providing on its own system. Under the *pro forma* OATT, a public utility may refuse to provide open access transmission service to a non-public utility if the non-public utility refuses to reciprocate.'' Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 163.

[901] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 818.

[902] *Id.* P 819 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 163).

[903] *Id.*

[904] *See* discussion *supra* at section 0.

[905] Sacramento Municipal Utility District at 20.

[906] *See* discussion *supra* at section 0.

[907] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 821.

[908] *Id.* P 818.

[909] 5 CFR 1320.11(b).

a formal submission to OMB for review and approval under section 3507(d) of the Paperwork Reduction Act of 1995.[910]

781. The burden estimates in this order on rehearing and clarification of Order No. 1000 represent the incremental burden changes related only to the new and revised requirements set forth in this order. It also should be noted that the burden estimates are averages for all of the filers.

Burden Estimate and Information Collection Costs: The estimated Public Reporting burden and cost for the new and revised requirements contained in this order follow.

FERC–917—New and revised reporting requirements in order 1000–A in RM10–23	Annual number of respondents (Filers)	Annual number of responses	Hours per response	Total annual hours in year 1	Total annual hours in subsequent years
Transmission Providers (TP) develop & maintain enrollment process defining how entities make choice to become part of trans. planning region; and include (& maintain) in OATT a list of all pub. & non-pub. utility trans. providers enrolled as TP in planning region.	132	1	2 in Year 1; 1 in Yrs. 2 & 3	264	132
Transmission Developers (TD) submit development schedule (if selected in regional plan for cost allocation).	140	1	4 (each in Yrs. 1–3)	560	560
TP describe in OATT how regional trans. planning process gives stakeholders chance to participate & how stakeholders & TD can propose interregional trans. facilities for TP in neighboring region to evaluate jointly.	132	1	5 in Year 1; 0.5 in Yrs. 2&3	660	66
To the extent that a TP considers either cost containment or cost recovery provisions as part of cost allocat. method for regional or interregional facility, such provisions may be included in its compliance filing.	132	1	18 in Year 1; 1 in Yrs. 2&3	2,376	132
Total Estimated Additional Burden Hours, for FERC–917 due to Order 1000–A in RM10–23.	....	....	....	3,860	890

Cost to Comply:

Year 1: $440,040 [3,860 hours × $114 per hour[911]]

Subsequent Years: $101,460 [890 hours × $114 per hour]

Title: FERC–917

Action: Clarification to Collection.

OMB Control No.: 1902–0233.

Respondents: Transmission Developers and Public Utility Transmission Providers. An RTO or ISO also may file some materials on behalf of its members.

Frequency of Responses: Initial filing and subsequent filings.

Necessity of the Information:

782. Building on the reforms in Order No. 890, the Federal Energy Regulatory Commission provides these clarifications to the amendments to the *pro forma* OATT to correct certain deficiencies in the transmission planning and cost allocation requirements for public utility transmission providers adopted in Order No. 1000. The purpose of Order No. 1000 is to strengthen the *pro forma* OATT, so that the transmission grid can better support wholesale power markets and ensure that Commission-jurisdictional services are provided at rates, terms, and conditions that are just and reasonable and not unduly discriminatory or preferential. We expect to achieve this goal through Order No. 1000 by reforming electric transmission planning requirements and establishing a closer link between cost allocation and regional transmission planning processes.

783. Interested persons may obtain information on reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director, email: *DataClearance@ferc.gov*, Phone: (202) 502–8663, fax: (202) 273–0873. Comments concerning the collection of information and the associated burden estimate(s), may also be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street NW., Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395–4638, fax (202) 395–7285]. Due to security concerns, comments should be sent electronically to the following email address: *oira_submission@omb.eop.gov*. Comments submitted to OMB should include OMB Control No. 1902–0233 and Docket No. RM10–23–001.

VII. Document Availability

784. In addition to publishing the full text of this document in the **Federal Register,** the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (*http://www.ferc.gov*) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street NE., Room 2A, Washington, DC 20426.

785. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary,

[910] 44 U.S.C. 3507(d).

[911] The estimated cost of $114 an hour is the average of the hourly costs of: Attorney ($200), consultant ($150), technical ($80), and administrative support ($25).

type the docket number excluding the last three digits of this document in the docket number field.

786. User assistance is available for eLibrary and the Commission's Web site during normal business hours from FERC Online Support at 202–502–6652 (toll free at 1–866–208–3676) or email at *ferconlinesupport@ferc.gov*, or the Public Reference Room at (202) 502–8371, TTY (202) 502–8659. Email the Public Reference Room at *public.referenceroom@ferc.gov*.

VIII. Effective Date and Congressional Notification

787. Changes to Order No. 1000 made in this order on rehearing and clarification will be effective on July 2, 2012. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule on rehearing and clarification of Order No. 1000 is not a ''major rule'' as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

Note: The following appendices will not be published in the *Code of Federal Regulations.*

Appendix A: Abbreviated Names of Petitioners

Abbreviation	Petitioner names
Ad Hoc Coalition of Southeastern Utilities	Central Electric Power Cooperative, Inc.; Dalton Utilities; Georgia Transmission Corporation; JEA; MEAG Power; Orlando Utilities Commission; Progress Energy Service Company, LLC (on behalf of Progress Energy Carolinas, Inc. and Progress Energy Florida, Inc.); South Carolina Electric & Gas Company; South Carolina Public Service Authority (Santee Cooper); and Southern Company Services, Inc. (on behalf of Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Southern Power Company).
AEP	American Electric Power Service Corporation.
Alabama PSC	Alabama Public Service Commission.
Ameren	Ameren Services Company.
American Transmission	American Transmission Company LLC.
APPA	American Public Power Association.
Arizona Cooperative and Southwestern Transmission.	Arizona Electric Power Cooperative, Inc. and Southwest Transmission Cooperative, Inc.
AWEA	American Wind Energy Association.
Baltimore Gas & Electric	Baltimore Gas & Electric Company.
Bonneville Power	Bonneville Power Administration.
California ISO	California Independent System Operator Corporation.
California State Water Project	California Department of Water Resources State Water Project.
Coalition for Fair Transmission Policy	CMS Energy Corporation; Consolidated Edison; DTE Energy Company; Progress Energy, Inc.; Public Service Enterprise Group; SCANA Corporation; Southern Company.[912]*
Dayton Power and Light	Dayton Power and Light Company (The).
Duke	Duke Energy Corporation.
Edison Electric Institute	Edison Electric Institute.
ELCON, AF&PA, and the Associated Industrial Groups.	Electricity Consumers Resource Council, American Forest and Paper Association, Electricity Consumers Resource Council; American Chemistry Council; Association of Businesses Advocating Tariff Equity; Carolina Utility Customers Association; Coalition of Midwest Transmission Customers; Florida Industrial Power Users Group; Georgia Industrial Group-Electric; Industrial Energy Users—Ohio; Oklahoma Industrial Energy Consumers; PJM Industrial Customer Coalition; West Virginia Energy Users Group; and Wisconsin Industrial Energy Group.
Energy Future Coalition Group	Energy Future Coalition; American Wind Energy Association; Center for Energy Efficiency and Renewable Technologies; Center for Rural Affairs; Climate and Energy Project; Denali Energy Inc.; Fresh Energy; Gradient Resources, Inc.; Iberdrola Renewables; Interwest Energy Alliance; Natural Resources Defense Council; Project for Sustainable FERC Energy Policy; Solar Energy Industries Association; The Stella Group, Ltd.; Union of Concerned Scientists; Western Grid Group; Wind on the Wires; and WIRES.*
FirstEnergy Service Company	FirstEnergy Service Company, on behalf of FirstEnergy Companies: Ohio Edison Company; Pennsylvania Power Company; The Cleveland Electric Illuminating Company; The Toledo Edison Company; American Transmission Systems, Incorporated; Jersey Central Power & Light Company; Metropolitan Edison Company; and Pennsylvania Electric Company, and FirstEnergy Solutions Corp. and their respective electric utility subsidiaries and affiliates.
Florida PSC	Florida Public Service Commission.
Georgia PSC	Georgia Public Service Commission.
Illinois Commerce Commission	Illinois Commerce Commission.
ITC Companies	International Transmission Company; Michigan Electric Transmission Company, LLC; ITC Midwest LLC; ITC Great Plains, LLC; and Green Power Express LP.
Joint Petitioners	American Electric Power Corp.; AWEA; Iberdrola Renewables; ITC Holdings Corp.; NextEra Energy, Inc.; MidAmerican Energy.
Kentucky PSC	Kentucky Public Service Commission.
Large Public Power Council	Austin Energy; Chelan County Public Utility District No. 1; Clark Public Utilities; Colorado Springs Utilities; CPS Energy (San Antonio); ElectriCities of North Carolina; Grant County Public Utility District; IID Energy (Imperial Irrigation District); JEA (Jacksonville, FL); Long Island Power Authority; Los Angeles Department of Water and Power; Lower Colorado River Authority; MEAG Power, Nebraska Public Power District; New York Power Authority; Omaha Public Power District; Orlando Utilities Commission; Platte River Power Authority; Puerto Rico Electric Power Authority; Sacramento Municipal Utility District; Salt River Project; Santee Cooper; Seattle City Light; Snohomish County Public Utility District No. 1; and Tacoma Public Utilities.*

Abbreviation	Petitioner names
Long Island Power Authority	Long Island Power Authority and LIPA.
LS Power	LS Power Transmission, LLC.
MEAG Power	MEAG Power.
MISO	Midwest Independent System Transmission Operator, Inc.
MISO Transmission Owners Group 1	The Midwest ISO Transmission Owners for this filing consist of: Ameren Services Company, as agent for Union Electric Company d/b/a Ameren Missouri, Ameren Illinois Company d/b/a Ameren Illinois and Ameren Transmission Company of Illinois; American Transmission Company LLC ("ATC"); City Water, Light & Power (Springfield, IL); Dairyland Power Cooperative; Great River Energy; Indianapolis Power & Light Company; MidAmerican Energy Company; Minnesota Power (and its subsidiary Superior Water, L&P); Montana- Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Electric Company; Otter Tail Power Company; Southern Indiana Gas & Electric Company (d/b/a Vectren Energy Delivery of Indiana); Southern Minnesota Municipal Power Agency; and Wolverine Power Supply Cooperative, Inc.
MISO Transmission Owners Group 2	The Midwest ISO Transmission Owners for this filing consist of: Ameren Services Company, as agent for Union Electric Company d/b/a Ameren Missouri, Ameren Illinois Company d/b/a Ameren Illinois and Ameren Transmission Company of Illinois; City Water, Light & Power (Springfield, IL); Dairyland Power Cooperative; Great River Energy; Hoosier Energy Rural Electric Cooperative, Inc.; Indianapolis Power & Light Company; MidAmerican Energy Company; Minnesota Power (and its subsidiary Superior Water, L&P); Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Electric Company; Otter Tail Power Company; Southern Illinois Power Cooperative; Southern Indiana Gas & Electric Company (d/b/a Vectren Energy Delivery of Indiana); Southern Minnesota Municipal Power Agency; and Wolverine Power Supply Cooperative, Inc.
MISO Northeast	MISO Northeast Transmission Customers of Consumers.
NARUC	National Association of Regulatory Utility Commissioners.
National Rural Electric Coops	National Rural Electric Cooperative Association.
NV Energy	Nevada Power Company and Sierra Pacific Power Company.
New York ISO	New York Independent System Operator, Inc.
New York PSC	New York State Public Service Commission.
New York Transmission Owners	Central Hudson Gas & Electric Corporation; Consolidated Edison Company of New York, Inc.; New York Power Authority; Long Island Power Authority; New York State Electric & Gas Corporation; and Niagara Mohawk Power Corporation; Orange and Rockland Utilities, Inc.; and Rochester Gas and Electric Corporation.
NextEra	NextEra Energy, Inc.
North Carolina Agencies	North Carolina Utilities Commission and Public Staff of the North Carolina Utilities Commission.
Northern Tier Transmission Group	Northern Tier Transmission Group.
Oklahoma Gas and Electric Company	Oklahoma Gas and Electric Company.
PPL Companies	PPL Electric Utilities Corporation; Lower Mount Bethel Energy, LLC; PPL Brunner Island, LLC; PPL Holtwood, LLC; PPL Martins Creek, LLC; PPL Montour, LLC; PPL Susquehanna, LLC; PPL University Park, LLC; PPL EnergyPlus, LLC; PPL GreatWorks, LLC; PPL Maine, LLC; PPL Wallingford Energy, LLC; PPL New Jersey Solar, LLC; PPL New Jersey Biogas, LLC; PPL Renewable Energy, LLC; PPL Montana, LLC; PPL Colstrip I, LLC; PPL Colstrip II, LLC; Louisville Gas and Electric Company; Kentucky Utilities Company; and LG&E Energy Marketing LLC.*
PSEG Companies	Public Service Electric and Gas Company; PSEG Power LLC; and PSEG Energy Resources & Trade LLC.
Sacramento Municipal Utility District	Sacramento Municipal Utility District.
South Carolina Regulatory Staff	South Carolina Office of Regulatory Staff.
Southern California Edison	Southern California Edison Company.
Southern Companies	Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; and Southern Power Company.
Sponsoring PJM Transmission Owners	Certain Sponsoring PJM Transmission Owners (American Transmission Systems, Incorporated; Jersey Central Power & Light Company; Metropolitan Edison Company; Monongahela Power Company; Pennsylvania Electric Company; The Potomac Edison Company; Trans-Allegheny Interstate Line Company; and West Penn Power Company (collectively, the FirstEnergy Companies); Baltimore Gas and Electric Company; The Dayton Power and Light Company; Duquesne Light Company; Public Service Electric and Gas Company; PSEG Power LLC and PSEG Energy Resources & Trade LLC (collectively, PSEG Companies); and Virginia Electric and Power Company).
Sunflower, Mid-Kansas and Western Farmers	Sunflower Electric Power Corporation and Mid-Kansas Electric Company, LLC and Western Farmers Electric Cooperative.
Transmission Access Policy Study Group	Transmission Access Policy Study Group.
Transmission Dependent Utility Systems	Arkansas Electric Cooperative Corporation; Golden Spread Electric Cooperative, Inc.; Kansas Electric Power Cooperative, Inc.; North Carolina Electric Membership Corporation; and Seminole Electric Cooperative, Inc.; and PowerSouth Energy Cooperative.*
Vermont Department of Public Service and the Vermont Public Service Board.	Vermont Department of Public Service and the Vermont Public Service Board
Western Independent Transmission Group	Western Independent Transmission Group.

Abbreviation	Petitioner names
WIRES	Working Group for Investment in Reliable and Economic Electric Systems.
Wisconsin PSC	Public Service Commission of Wisconsin.
Xcel	Xcel Energy Services Inc.

Appendix B: *Pro Forma* Open Access Transmission Tariff

Pro Forma OATT

Attachment K

Transmission Planning Process

Local Transmission Planning

The Transmission Provider shall establish a coordinated, open and transparent planning process with its Network and Firm Point-to-Point Transmission Customers and other interested parties to ensure that the Transmission System is planned to meet the needs of both the Transmission Provider and its Network and Firm Point-to-Point Transmission Customers on a comparable and not unduly discriminatory basis. The Transmission Provider's coordinated, open and transparent planning process shall be provided as an attachment to the Transmission Provider's Tariff.

The Transmission Provider's planning process shall satisfy the following nine principles, as defined in Order No. 890: Coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning studies, and cost allocation for new projects. The planning process also shall include the procedures and mechanisms for considering transmission needs driven by Public Policy Requirements consistent with Order No. 1000. The planning process also shall provide a mechanism for the recovery and allocation of planning costs consistent with Order No. 890.

The description of the Transmission Provider's planning process must include sufficient detail to enable Transmission Customers to understand:

(i) The process for consulting with customers;

(ii) The notice procedures and anticipated frequency of meetings;

(iii) The methodology, criteria, and processes used to develop a transmission plan;

(iv) The method of disclosure of criteria, assumptions and data underlying a transmission plan;

(v) The obligations of and methods for Transmission Customers to submit data to the Transmission Provider;

(vi) The dispute resolution process;

(vii) The Transmission Provider's study procedures for economic upgrades to address congestion or the integration of new resources;

(viii) The Transmission Provider's procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000; and

(ix) The relevant cost allocation method or methods.

Regional Transmission Planning

The Transmission Provider shall participate in a regional transmission planning process through which transmission facilities and non-transmission alternatives may be proposed and evaluated. The regional transmission planning process also shall develop a regional transmission plan that identifies the transmission facilities necessary to meet the needs of transmission providers and transmission customers in the transmission planning region. The regional transmission planning process must be consistent with the provision of Commission-jurisdictional services at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential, as described in Order No. 1000. The regional transmission planning process shall be described in an attachment to the Transmission Provider's Tariff.

The Transmission Provider's regional transmission planning process shall satisfy the following seven principles, as set out and explained in Order Nos. 890 and 1000: Coordination, openness, transparency, information exchange, comparability, dispute resolution, and economic planning studies. The regional transmission planning process also shall include the procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000. The regional transmission planning process shall provide a mechanism for the recovery and allocation of planning costs consistent with Order No. 890.

The regional transmission planning process shall include a clear enrollment process for public and non-public utility transmission providers that make the choice to become part of a transmission planning region. The regional transmission planning process shall be clear that enrollment will subject enrollees to cost allocation if they are found to be beneficiaries of new transmission facilities selected in the regional transmission plan for purposes of cost allocation. Each Transmission Provider shall maintain a list of enrolled entities in the Transmission Provider's Tariff.

Nothing in the regional transmission planning process shall include an unduly discriminatory or preferential process for transmission project submission and selection.

The description of the regional transmission planning process must include sufficient detail to enable Transmission Customers to understand:

(i) The process for enrollment in the regional transmission planning process;

(ii) The process for consulting with customers;

(iii) The notice procedures and anticipated frequency of meetings;

(iv) The methodology, criteria, and processes used to develop a transmission plan;

(v) The method of disclosure of criteria, assumptions and data underlying transmission plan;

(vi) The obligations of and methods for transmission customers to submit data;

(vii) Process for submission of data by nonincumbent developers of transmission projects that wish to participate in the transmission planning process and seek regional cost allocation;

(viii) Process for submission of data by merchant transmission developers that wish to participate in the transmission planning process;

(ix) The dispute resolution process;

(x) The study procedures for economic upgrades to address congestion or the integration of new resources;

(xi) The procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000; and

(xii) The relevant cost allocation method or methods.

The regional transmission planning process must include a cost allocation method or methods that satisfy the six regional cost allocation principles set forth in Order No. 1000.

Interregional Transmission Coordination

The Transmission Provider, through its regional transmission planning process, must coordinate with the public utility transmission providers in each neighboring transmission planning region within its interconnection to address transmission planning coordination issues related to interregional transmission facilities. The interregional transmission coordination procedures must include a detailed description of the process for coordination between public utility transmission providers in neighboring transmission planning regions (i) with respect to each interregional transmission facility that is proposed to be located in both transmission planning regions and (ii) to identify possible interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities. The interregional transmission coordination procedures shall be described in an attachment to the Transmission Provider's Tariff.

The Transmission Provider must ensure that the following requirements are included in any applicable interregional transmission coordination procedures:

(1) A commitment to coordinate and share the results of each transmission planning region's regional transmission plans to identify possible interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than

[912] A "*" indicates that the composition of this group has changed since the Final Rule proceeding.

separate regional transmission facilities, as well as a procedure for doing so;

(2) A formal procedure to identify and jointly evaluate transmission facilities that are proposed to be located in both transmission planning regions;

(3) An agreement to exchange, at least annually, planning data and information; and

(4) A commitment to maintain a Web site or email list for the communication of information related to the coordinated planning process.

The Transmission Provider must work with transmission providers located in neighboring transmission planning regions to develop a mutually agreeable method or methods for allocating between the two transmission planning regions the costs of a new interregional transmission facility that is located within both transmission planning regions. Such cost allocation method or methods must satisfy the six interregional cost allocation principles set forth in Order No. 1000 and must be included in the Transmission Provider's Tariff.

[FR Doc. 2012–12418 Filed 5–30–12; 8:45 am]

BILLING CODE 6717–01–P

FEDERAL REGISTER

Vol. 77 Thursday,
No. 105 May 31, 2012

Part III

Department of Energy

10 CFR Parts 429 and 430
Energy Conservation Program: Energy Conservation Standards for Residential Clothes Washers; Final Rule and Proposed Rule

DEPARTMENT OF ENERGY

10 CFR Parts 429 and 430

[Docket Number EERE–2008–BT–STD–0019]

RIN 1904–AB90

Energy Conservation Program: Energy Conservation Standards for Residential Clothes Washers

AGENCY: Office of Energy Efficiency and Renewable Energy, Department of Energy.

ACTION: Direct final rule.

SUMMARY: The Energy Policy and Conservation Act of 1975 (EPCA), as amended, prescribes energy conservation standards for various consumer products and certain commercial and industrial equipment, including residential clothes washers. EPCA also requires the U.S. Department of Energy (DOE) to determine whether amended standards would be technologically feasible and economically justified, and would save a significant amount of energy. In this direct final rule, DOE is adopting amended energy conservation standards for residential clothes washers. It has determined that the amended energy conservation standards for these products would result in significant conservation of energy, and are technologically feasible and economically justified. A notice of proposed rulemaking that proposes identical energy efficiency standards is published elsewhere in today's **Federal Register**. If DOE receives adverse comment and determines that such comment may provide a reasonable basis for withdrawing the direct final rule, this final rule will be withdrawn and DOE will proceed with the proposed rule.

DATES: The effective date of this rule is September 28, 2012 unless adverse comment is received by September 18, 2012. If adverse comments are received that DOE determines may provide a reasonable basis for withdrawal of the final rule, a timely withdrawal of this rule will be published in the **Federal Register**. If no such adverse comments are received, compliance with the amended standards established for residential clothes washers in today's final rule will be required on March 7, 2015 and January 1, 2018, as set forth in Table I.1 in **SUPPLEMENTARY INFORMATION**.

ADDRESSES: The docket for this rulemaking is available for review at *www.regulations.gov,* including **Federal Register** notices, framework documents, public meeting attendee lists and transcripts, comments, and other supporting materials. All documents in the docket are listed in the *regulations.gov* index. Not all documents listed in the index may be publicly available, however, such as information that is exempt from public disclosure.

A link to the docket web page can be found at: *www.regulations.gov/#!docketDetail;D=EERE-2008-BT-STD-0019.* The *regulations.gov* web page contains instructions on how to access all documents, including public comments, in the docket.

FOR FURTHER INFORMATION CONTACT:

Stephen L. Witkowski, U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, Building Technologies Program, EE–2J, 1000 Independence Avenue SW., Washington, DC 20585–0121. Telephone: (202) 586–7463. Email: *Stephen.Witkowski@ee.doe.gov.*

Ms. Elizabeth Kohl, U.S. Department of Energy, Office of the General Counsel, GC–71, 1000 Independence Avenue SW., Washington, DC 20585–0121. Telephone: (202) 586–7796. Email: *Elizabeth.Kohl@hq.doe.govmailto:.*

SUPPLEMENTARY INFORMATION:

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I. Summary of the Direct Final Rule and Its Benefits

Title III, Part B [1] of the Energy Policy and Conservation Act of 1975 (EPCA or the Act), Public Law 94–163 (42 U.S.C. 6291–6309, as codified), established the Energy Conservation Program for Consumer Products Other Than Automobiles. Pursuant to EPCA, any new or amended energy conservation standard that DOE prescribes for certain products, such as residential clothes washers, shall be designed to achieve the maximum improvement in energy efficiency that is technologically feasible and economically justified. (42 U.S.C. 6295(o)(2)(A)) Furthermore, the new or amended standard must result in a significant conservation of energy. (42 U.S.C. 6295(o)(3)(B)) In accordance with these and other statutory provisions discussed in this notice, DOE is adopting amended energy conservation standards for residential clothes washers. The amended standards, which are a minimum allowable integrated modified energy factor (IMEF) and maximum allowable integrated water factor (IWF), are shown in Table I–1. One set of amended standards applies to all products listed in Table I–1 manufactured in, or imported into, the United States on or after March 7, 2015. A second set of amended standards applies to the two top-loading product classes for products manufactured in, or imported into, the United States on or after January 1, 2018.

TABLE I–1—AMENDED ENERGY CONSERVATION STANDARDS FOR RESIDENTIAL CLOTHES WASHERS (COMPLIANCE STARTING 2015 AND 2018)

Product class	Compliance date: March 7, 2015		Compliance date: January 1, 2018	
	Minimum IMEF *	Maximum IWF †	Minimum IMEF *	Maximum IWF †
1. Top-loading, Compact (less than 1.6 ft³ capacity)	0.86	14.4	1.15	12.0
2. Top-loading, Standard	1.29	8.4	1.57	6.5
3. Front-loading, Compact (less than 1.6 ft³ capacity)	1.13	8.3	N/A	
4. Front-loading, Standard	1.84	4.7	N/A	

* IMEF (integrated modified energy factor) is calculated as the clothes container capacity in cubic feet divided by the sum, expressed in kilowatt-hours (kWh), of: (1) The total weighted per-cycle hot water energy consumption; (2) the total weighted per-cycle machine electrical energy consumption; (3) the per-cycle energy consumption for removing moisture from a test load; and (4) the per-cycle standby and off mode energy consumption.

† IWF (integrated water consumption factor) is calculated as the sum, expressed in gallons per cycle, of the total weighted per-cycle water consumption for all wash cycles divided by the clothes container capacity in cubic feet.

These standard levels are equivalent to those proposed in a comment submitted by groups representing manufacturers; energy and environmental advocates; and consumer groups. This collective set of comments, titled ''Agreement on Minimum Federal Efficiency Standards, Smart Appliances, Federal Incentives and Related Matters for Specified Appliances'' (the ''Joint Petition'' [2]), recommends specific energy conservation standards for residential clothes washers that, in the commenters' view, would satisfy the EPCA requirements in 42 U.S.C. 6295(o). The amended standards that DOE is adopting in today's direct final rule are the clothes washer efficiencies recommended in the Joint Petition (shown in Table I–2), evaluated according to DOE's clothes washer test procedure at appendix J2 and expressed in integrated energy and water use metrics.

[1] For editorial reasons, upon codification in the U.S. Code, Part B was redesignated Part A.

[2] DOE Docket No. EERE–2008–BT–STD–0019, Comment 35.

TABLE I–2—JOINT PETITION RECOMMENDED ENERGY CONSERVATION STANDARDS FOR RESIDENTIAL CLOTHES WASHERS

Product class	Compliance date: 2015		Compliance date: 2018	
	Minimum MEF *	Maximum WF †	Minimum MEF *	Maximum WF †
1. Top-loading, Compact (less than 1.6 ft³ capacity)	1.26	14.0	1.81	11.6
2. Top-loading, Standard	1.72	8.0	2.0	6.0
3. Front-loading, Compact (less than 1.6 ft³ capacity)	1.72	8.0	N/A	
4. Front-loading, Standard	2.20	4.5	N/A	

* MEF (modified energy factor) is calculated as the clothes container capacity in cubic feet divided by the sum, expressed in kilowatt-hours (kWh), of: (1) The total weighted per-cycle hot water energy consumption; (2) the total weighted per-cycle machine electrical energy consumption; and (3) the per-cycle energy consumption for removing moisture from a test load.

† WF (water consumption factor) is calculated as the sum, expressed in gallons per cycle, of the total weighted per-cycle water consumption for the cold wash/cold rinse cycle divided by the clothes container capacity in cubic feet.

As discussed further in III.A.1, DOE did not maintain the top-loading semi-automatic and suds-saving product classes, and therefore did not consider these product classes in its analysis. DOE also added a front-loading, compact product class.

A. Benefits and Costs to Consumers

Table I–3 presents DOE's evaluation of the economic impacts of today's standards on consumers of residential clothes washers, as measured by the average life-cycle cost (LCC) savings and the median payback period. The impacts on consumers, as measured by the average LCC savings, are positive for all product classes.

TABLE I–3—IMPACTS OF TODAY'S STANDARDS ON CONSUMERS OF RESIDENTIAL CLOTHES WASHERS

Product class	Average LCC savings (*2010$*)	Median payback period (*years*)
Top-Loading, Standard *	268/366	0.4/0.9
Front-Loading, Standard	37	1.3
Top-Loading, Compact *	159/312	0.5/2.1
Front-Loading, Compact	54	0.8

* The first value refers to the standards in 2015, and the second value refers to the standards in 2018.

B. Impact on Manufacturers

The industry net present value (INPV) is the sum of the discounted cash flows to the industry from the base year through the end of the analysis period (2015 to 2044). Using a real discount rate of 8.5 percent, DOE estimates that the industry net present value (INPV) for manufacturers of clothes washers is $2,586 million in 2010$. Under today's standards, DOE expects that manufacturers may lose up to 33 percent of their INPV, which is approximately $859 million. Additionally, based on DOE's interviews with the manufacturers of clothes washers, DOE does not expect any plant closings or significant loss of employment.

C. National Benefits

DOE's analyses indicate that today's standards would save a significant amount of energy and water over 30 years (2015–2044)—an estimated 2.04 quads of energy and 3.03 trillion gallons of water. In addition, DOE expects the energy savings from today's standards to eliminate the need for approximately 1.30 gigawatts (GW) of generating capacity by 2044.

The cumulative national net present value (NPV) of total consumer costs and savings of today's standards in 2010$ ranges from $13.01 billion (at a 7-percent discount rate) to $31.29 billion (at a 3-percent discount rate). This NPV expresses the estimated total value of future operating-cost savings minus the estimated increased product costs for products purchased in 2015–2044, discounted to 2011.

In addition, today's standards would have significant environmental benefits. The energy savings would result in cumulative greenhouse gas emission reductions of approximately 113 million metric tons (Mt) of carbon dioxide (CO_2) from 2015 through 2044. During this period, the standards would also result in emissions reductions [3] of approximately 94.1 thousand tons of nitrogen oxides (NO_X) and 0.269 ton of mercury (Hg).[4] DOE estimates that the net present monetary value of the CO_2 emissions reductions is between $530 and $8,450 million, expressed in 2010$ and discounted to 2011. The value of the CO_2 reductions is calculated using a range of values per metric ton of CO_2 developed by a recent interagency process. The derivation of these Social Cost of Carbon (SCC) values is discussed in section IV.M.1. DOE also estimates that the net present monetary value of the NO_X emissions reductions, expressed in 2010$ and discounted to 2011, is $12 to $122 million at a 7-percent discount rate, and $28 to $286 million at a 3-percent discount rate.[5]

[3] DOE calculates emissions reductions relative to the most recent version of the *Annual Energy Outlook* (*AEO*) Reference case forecast. As noted in section 15.2 of the direct final rule TSD chapter 15, this forecast accounts for emissions reductions from in-place regulations, including the Clean Air Interstate Rule (CAIR, 70 FR 25162 (May 12, 2005)), but not the Clean Air Mercury Rule (CAMR, 70 FR 28606 (May 18, 2005)). Subsequent regulations, including the recently finalized transport rule, the Cross-State Air Pollution rule issued on July 6, 2011, do not appear in the forecast at this time.

[4] Results for NO_X and Hg are presented in short tons. One short ton equals 2,000 lbs.

[5] DOE is aware of multiple agency efforts to determine the appropriate range of values used in evaluating the potential economic benefits of reduced Hg emissions. DOE has decided to await further guidance regarding consistent valuation and reporting of Hg emissions before it once again monetizes Hg emissions reductions in its rulemakings.

The benefits and costs of today's standards, for products sold in 2015–2044, can also be expressed in terms of annualized values. The annualized monetary values are the sum of (1) the annualized national economic value, expressed in 2010$, of the benefits from operating the product (consisting primarily of operating cost savings from using less energy, minus increases in equipment purchase and installation costs, which is another way of representing consumer NPV, plus (2) the annualized monetary value of the benefits of emission reductions, including CO_2 emission reductions.[6]

Although adding the value of consumer savings to the values of emission reductions provides a valuable perspective, two issues should be considered. First, the national operating cost savings are domestic U.S. consumer monetary savings that occur as a result of market transactions, while the value of CO_2 reductions is based on a global value. Second, the assessments of operating cost savings and CO_2 savings are performed with different methods that use quite different time frames for analysis. The national operating cost savings is measured for the lifetime of products shipped in 2015–2044. The SCC values, on the other hand, reflect the present value of some future climate-related impacts resulting from the emission of one metric ton of carbon dioxide in each year. These impacts continue well beyond 2100.

Table I–4 shows the annualized values for today's standards for residential clothes washers, expressed in 2010$. The results under the primary estimate are as follows. Using a 7-percent discount rate for benefits and costs other than CO_2 reductions, for which DOE used a 3-percent discount rate along with the SCC series corresponding to a value of $22.3/ton in 2010, the cost of the standards for clothes washers in today's rule is $185 million per year in increased equipment costs, while the annualized benefits are $1,234 million per year in reduced equipment operating costs, $141.7 million in CO_2 reductions, and $5.4 million in reduced NO_X emissions. In this case, the net benefit amounts to $1.20 billion per year. Using a 3-percent discount rate for all benefits and costs and the SCC series corresponding to a value of $22.3/ton in 2010, the cost of the standards for clothes washers in today's rule is $212 million per year in increased equipment costs, while the benefits are $1,808 million per year in reduced operating costs, $141.7 million in CO_2 reductions, and $8.0 million in reduced NO_X emissions. In this case, the net benefit amounts to $1.75 billion per year.

TABLE I–4—ANNUALIZED BENEFITS AND COSTS OF AMENDED STANDARDS FOR RESIDENTIAL CLOTHES WASHERS FOR PRODUCTS SOLD IN 2015–2044

	Discount rate	Primary estimate*	Low net benefits estimate*	High net benefits estimate*
		Monetized (million 2010$/year)		
Benefits				
Operating Cost Savings	7%	1234	1101	1379.
	3%	1808	1587	2042.
CO_2 Reduction at $4.9/t **	5%	34.5	31.7	37.4.
CO_2 Reduction at $22.3/t **	3%	142	130	154.
CO_2 Reduction at $36.5/t **	2.5%	226	207	246.
CO_2 Reduction at $67.6/t **	3%	431	396	469.
NO_X Reduction at $2,537/t **	7%	5.40	5.03	5.82.
	3%	8.01	7.39	8.68.
Total †	7% plus CO_2 range	1274 to 1671	1137 to 1502	1423 to 1854.
	7%	1381	1236	1539.
	3% plus CO_2 range	1851 to 2248	1626 to 1991	2089 to 2520.
	3%	1958	1725	2205.
Costs				
Incremental Product Costs	7%	185	258	200.
	3%	212	309	230.
Total Net Benefits				
Total †	7% plus CO_2 range	1088 to 1485	880 to 1244	1223 to 1654.
	7%	1196	978	1339.
	3% plus CO_2 range	1639 to 2036	1317 to 1682	1859 to 2291.
	3%	1746	1416	1976.

* The Primary, Low Benefits, and High Benefits Estimates utilize forecasts of energy prices and housing starts (which affect product shipments) from the *AEO2010* Reference case, Low Economic Growth case, and High Economic Growth case, respectively. In addition, incremental product costs reflect a declining trend using the default product price trend in the Primary Estimate and the High Benefits Estimate, and constant product prices in the Low Benefits Estimate. Because product prices are constant in the Low Benefits Estimate, the incremental product costs are higher than in the other two estimates. Although the price trends in the Primary Estimate and the High Benefits Estimate are the same, the incremental product costs are higher in the High Benefits Estimate because this case assumes High Economic Growth and thus has more product shipments. The approach used for forecasting product prices is explained in section IV.F.1.

[6] DOE used a two-step calculation process to convert the time-series of costs and benefits into annualized values. First, DOE calculated a present value in 2011, the year used for discounting the NPV of total consumer costs and savings, for the time-series of costs and benefits using discount rates of three and seven percent for all costs and benefits except for the value of CO_2 reductions. For the latter, DOE used a range of discount rates, as shown in Table I–3. From the present value, DOE then calculated the fixed annual payment over a 30-year period that yields the same present value. The fixed annual payment is the annualized value. Although DOE calculated annualized values, this does not imply that the time-series of cost and benefits from which the annualized values were determined is a steady stream of payments.

** The CO_2 values represent global values (in 2010$) of the social cost of CO_2 emissions in 2010 under several scenarios. The values of $4.9, $22.3, and $36.5 per ton are the averages of SCC distributions calculated using 5%, 3%, and 2.5% discount rates, respectively. The value of $67.6 per ton represents the 95th percentile of the SCC distribution calculated using a 3% discount rate. The value for NO_X (in 2010$) is the average of the low and high values used in DOE's analysis.

† Total Benefits for both the 3% and 7% cases are derived using the SCC value calculated at a 3% discount rate, which is $22.3/ton in 2010 (in 2010$). In the rows labeled as "7% plus CO_2 range" and "3% plus CO_2 range," the operating cost and NO_X benefits are calculated using the labeled discount rate, and those values are added to the full range of CO_2 values.

D. Conclusion

Based on the analyses culminating in this final rule, DOE found the benefits to the nation of the standards (energy savings, water savings, favorable consumer LCC savings and payback period, positive NPV of consumer benefit, and emission reductions) outweigh the burdens (profit margin impacts that could result in a reduction in INPV for manufacturers). DOE has concluded that the standards in today's final rule represent the maximum improvement in energy efficiency that is technologically feasible and economically justified, and would result in significant conservation of energy. DOE further notes that residential clothes washers achieving these standard levels are already commercially available.

II. Introduction

The following section briefly discusses the statutory authority underlying today's final rule, as well as some of the relevant historical background related to the establishment of standards for residential clothes washers.

A. Authority

Title III, Part B of the Energy Policy and Conservation Act of 1975 (EPCA or the Act), Public Law 94–163 (42 U.S.C. 6291–6309, as codified) established the Energy Conservation Program for Consumer Products Other Than Automobiles,[7] a program covering most major household appliances (collectively referred to as "covered products"), which includes the residential clothes washers that are the subject of this rulemaking. (42 U.S.C. 6292(a)(7)) EPCA prescribed energy conservation standards for these products (42 U.S.C. 6295(g)(9)(a)), and directed DOE to conduct three cycles of rulemakings to determine whether to amend these standards. (42 U.S.C. 6295(g)(4)(A), (g)(4)(B), and (g)(9)(B)) DOE also notes that under 42 U.S.C. 6295(m), DOE must also periodically review its energy conservation standards for covered products.

Pursuant to EPCA, DOE's energy conservation program for covered products consists essentially of four parts: (1) Testing; (2) labeling; (3) the establishment of Federal energy conservation standards; and (4) certification and enforcement procedures. The Federal Trade Commission (FTC) is primarily responsible for labeling, and DOE implements the remainder of the program. Subject to certain criteria and conditions, DOE is required to develop test procedures to measure the energy efficiency, energy use, or estimated annual operating cost of each covered product. (42 U.S.C. 6293) Manufacturers of covered products must use the prescribed DOE test procedure as the basis for certifying to DOE that their products comply with the applicable energy conservation standards adopted under EPCA and when making representations to the public regarding the energy use or efficiency of those products. (42 U.S.C. 6293(c) and 6295(s)) Similarly, DOE must use these test procedures to determine whether the products comply with standards adopted pursuant to EPCA. *Id.* The DOE test procedures for residential clothes washers appear at title 10 of the Code of Federal Regulations (CFR) part 430, subpart B, appendices J1 and J2. Until the compliance date of the amended energy and water conservation standards established in today's direct final rule, absent withdrawal of the rule by DOE pursuant to 42 U.S.C. 6295(p)(4), manufacturers must use the test procedures at appendix J1 to certify compliance. Subsequently, manufacturers must use the test procedures at appendix J2. Similarly, DOE will use the test procedure at appendix J1 for enforcement purposes until the compliance date of these amended energy and water conservation standards, and will subsequently use appendix J2. See section III.B for a detailed discussion of the test procedure amendments.

DOE must follow specific statutory criteria for prescribing amended standards for covered products. As indicated above, any amended standard for a covered product must be designed to achieve the maximum improvement in energy efficiency that is technologically feasible and economically justified. (42 U.S.C. 6295(o)(2)(A)) Furthermore, DOE may not adopt any standard that would not result in the significant conservation of energy. (42 U.S.C. 6295(o)(3)) In deciding whether an amended standard is economically justified, DOE must determine whether the benefits of the standard exceed its burdens. (42 U.S.C. 6295(o)(2)(B)(i)) DOE must make this determination after receiving comments on the proposed standard, and by, to the greatest extent practicable, considering the following seven factors:

1. The economic impact of the standard on manufacturers and consumers of the products subject to the standard;
2. The savings in operating costs throughout the estimated average life of the covered products in the type (or class) compared to any increase in the price, initial charges, or maintenance expenses for the covered products that are likely to result from the imposition of the standard;
3. The total projected amount of energy, or as applicable, water, savings likely to result directly from the imposition of the standard;
4. Any lessening of the utility or the performance of the covered products likely to result from the imposition of the standard;
5. The impact of any lessening of competition, as determined in writing by the Attorney General, that is likely to result from the imposition of the standard;
6. The need for national energy and water conservation; and
7. Other factors the Secretary of Energy (Secretary) considers relevant.

(42 U.S.C. 6295(o)(2)(B)(i)(I)–(VII))

EPCA allows DOE to issue a final rule (hereinafter referred to as a "direct final rule") establishing an energy conservation standard on receipt of a statement submitted jointly by interested persons that are fairly representative of relevant points of view (including representatives of manufacturers of covered products, States, and efficiency advocates) as determined by the Secretary, that contains recommendations with respect to an energy conservation standard that are in accordance with the provisions of 42 U.S.C. 6295(o). A notice of proposed rulemaking (NOPR) that proposes an identical energy efficiency standard must be published simultaneously with the final rule, and DOE must provide a public comment period of at least 110 days. 42 U.S.C. 6295(p)(4) Not later than

[7] For editorial reasons, upon codification in the U.S. Code, Part B was redesignated Part A.

120 days after issuance of the direct final rule, if one or more adverse comments or an alternative joint recommendation are received relating to the direct final rule, the Secretary must determine whether the comments or alternative recommendation may provide a reasonable basis for withdrawal under 42 U.S.C. 6295(o) or other applicable law. If the Secretary makes such a determination, DOE must withdraw the direct final rule and proceed with the simultaneously published notice of proposed rulemaking. DOE must publish in the **Federal Register** the reason why the direct final rule was withdrawn. *Id.*

Furthermore, EPCA contains what is known as an ''anti-backsliding'' provision, which prevents the Secretary from prescribing any amended standard that either increases the maximum allowable energy use or decreases the minimum required energy efficiency of a covered product. (42 U.S.C. 6295(o)(1)) Also, the Secretary may not prescribe an amended or new standard if interested persons have established by a preponderance of the evidence that the standard is likely to result in the unavailability in the United States of any covered product type (or class) of performance characteristics (including reliability), features, sizes, capacities, and volumes that are substantially the same as those generally available in the United States. (42 U.S.C. 6295(o)(4))

EPCA also establishes a rebuttable presumption that a standard is economically justified if the Secretary finds that the additional cost to the consumer of purchasing a product complying with an energy conservation standard level will be less than three times the value of the energy savings during the first year that the consumer will receive as a result of the standard, as calculated under the applicable test procedure. See 42 U.S.C. 6295(o)(2)(B)(iii).

Additionally, 42 U.S.C. 6295(q)(1) specifies requirements when promulgating a standard for a type or class of covered product that has two or more subcategories. DOE must specify a different standard level than that which applies generally to such type or class of products for any group of covered products which have the same function or intended use, if products within such group—(A) consume a different kind of energy from that consumed by other covered products within such type (or class); or (B) have a capacity or other performance-related feature which other products within such type (or class) do not have and such feature justifies a higher or lower standard than applies or will apply to the other products within that type or class. *Id.* In determining whether a performance-related feature justifies a different standard for a group of products, DOE must consider such factors as the utility to the consumer of such a feature and other factors DOE deems appropriate. *Id.* Any rule prescribing such a standard must include an explanation of the basis on which such higher or lower level was established. (42 U.S.C. 6295(q)(2)).

Federal energy conservation requirements generally supersede State laws or regulations concerning energy conservation testing, labeling, and standards. (42 U.S.C. 6297(a)–(c)) DOE may, however, grant waivers of Federal preemption for particular State laws or regulations, in accordance with the procedures and other provisions set forth under 42 U.S.C. 6297(d)).

Any final rule for new or amended energy conservation standards promulgated after July 1, 2010, must address standby mode and off mode energy use. (42 U.S.C. 6295(gg)(3)) Specifically, when DOE adopts a standard for a covered product after that date, it must, if justified by the criteria for adoption of standards under EPCA (42 U.S.C. 6295(o)), incorporate standby mode and off mode energy use into the standard, or, if that is not feasible, adopt a separate standard for such energy use for that product. (42 U.S.C. 6295(gg)(3)(A)–(B)) The current standard for residential clothes washers is based on modified energy factor (MEF), a metric that does not incorporate standby or off mode energy use. On March 7, 2012, DOE published a final rule revising the clothes washer test procedure (hereafter, the March 2012 TP final rule). 77 FR 13888. Use of the new test procedure in 10 CFR 430 subpart B appendix J2 will be required for clothes washers manufactured on or after the compliance date of the 2015 standard in this direct final rule. The revised test procedure establishes an ''integrated modified energy factor'' (IMEF), a metric that incorporates energy use in standby and off modes. The revised test procedure also includes updates to the active mode provisions of the test procedure, which affect the calculation of IMEF, and establishes an ''integrated water factor'' (IWF). In this final rule, DOE prescribes amended energy conservation standards based on IMEF and IWF.

DOE has also reviewed this regulation pursuant to Executive Order 13563, issued on January 18, 2011 (76 FR 3281, Jan. 21, 2011). Executive Order 13563 is supplemental to and explicitly reaffirms the principles, structures, and definitions governing regulatory review established in Executive Order 12866. To the extent permitted by law, agencies are required by Executive Order 13563 to: (1) Propose or adopt a regulation only upon a reasoned determination that its benefits justify its costs (recognizing that some benefits and costs are difficult to quantify); (2) tailor regulations to impose the least burden on society, consistent with obtaining regulatory objectives, taking into account, among other things, and to the extent practicable, the costs of cumulative regulations; (3) select, in choosing among alternative regulatory approaches, those approaches that maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity); (4) to the extent feasible, specify performance objectives, rather than specifying the behavior or manner of compliance that regulated entities must adopt; and (5) identify and assess available alternatives to direct regulation, including providing economic incentives to encourage the desired behavior, such as user fees or marketable permits, or providing information upon which choices can be made by the public.

We emphasize as well that Executive Order 13563 requires agencies ''to use the best available techniques to quantify anticipated present and future benefits and costs as accurately as possible.'' In its guidance, the Office of Information and Regulatory Affairs has emphasized that such techniques may include ''identifying changing future compliance costs that might result from technological innovation or anticipated behavioral changes.'' For the reasons stated in the preamble, DOE believes that today's direct final rule is consistent with these principles, including that, to the extent permitted by law, agencies adopt a regulation only upon a reasoned determination that its benefits justify its costs and select, in choosing among alternative regulatory approaches, those approaches that maximize net benefits.

Consistent with E.O. 13563, and the range of impacts analyzed in this rulemaking, the energy conservation standards adopted herein by DOE achieve maximum net benefits.

B. Background

1. Current Standards

In a final rule published on January 12, 2001 (2001 Final Rule), DOE prescribed amended energy conservation standards for residential clothes washers. 66 FR 3314. EPCA, as amended by EISA 2007, revised the energy conservation standards for residential clothes washers by establishing a maximum water factor value, effective January 1, 2011. These standards are set forth in Table II–1.

TABLE II–1—ENERGY CONSERVATION STANDARDS FOR RESIDENTIAL CLOTHES WASHERS ESTABLISHED IN THE 2001 FINAL RULE AND EISA 2007

Product class	MEF ft^3/kWh/cycle	WF gal/cycle/ft^3
Top-Loading, Compact (less than 1.6 ft^3 capacity)	* 0.65	N/A
Top-Loading, Standard	* 1.26	** 9.5
Front-Loading	* 1.26	** 9.5
Top-Loading, Semi-Automatic	N/A	N/A
Suds-Saving	N/A	N/A

* *Source:* 2001 Final Rule (66 FR 3314).
** *Source:* EISA 2007 (42 U.S.C. 6295(g)(9)).

The EPCA amendments in EISA 2007 also require DOE to publish a final rule no later than December 31, 2011 determining whether to amend the standards in effect for clothes washers manufactured on or after January 1, 2015. (42 U.S.C. 6295(g)(9)) Today's final rule fulfills this statutory requirement.

The EISA 2007 amendments further require that any final rule for new or amended energy conservation standards promulgated after July 1, 2010, address standby mode and off mode energy use. (42 U.S.C. 6295(gg)(3)) Specifically, when DOE adopts a standard for a covered product after that date, it must, if justified by the criteria for adoption of standards under EPCA (42 U.S.C. 6295(o)), incorporate standby mode and off mode energy use into the standard, or, if that is not feasible, adopt a separate standard for such energy use for that product. (42 U.S.C. 6295(gg)(3)(A)–(B)) Today's standards are based on an ''integrated modified energy factor'' (IMEF), which incorporates energy use in standby mode and off mode, and an ''integrated water factor'' (IWF), which more accurately represents consumer usage patterns compared to the current water factor metric.

2. History of Standards Rulemaking for Residential Clothes Washers

The National Appliance Energy Conservation Act of 1987 (NAECA), Public Law 100–12 (March 17, 1989), amended EPCA and required that all rinse cycles of clothes washers manufactured after January 1, 1988 include an unheated water option, but stated that such clothes washers may have a heated water rinse option. NAECA further required that DOE conduct two cycles of rulemakings to determine if amended standards are justified. (42 U.S.C. 6295(g)(2) and (4)).

To complete the first rulemaking cycle required by NAECA, DOE published an advance notice of proposed rulemaking (ANOPR) on May 18, 1988 (53 FR 17712), a NOPR on August 9, 1989 (54 FR 32744), and a final rule on May 14, 1991 (May 1991 final rule). 56 FR 22279. The May 1991 final rule mandated performance-based energy conservation standards for top-loading compact and standard clothes washers based on a minimum energy factor (EF) for products manufactured on or after May 14, 1994.

To complete the second rulemaking cycle required by NAECA, the Department published an ANOPR on November 14, 1994 to consider amending the energy conservation standards for clothes washers, dishwashers, and clothes dryers. 59 FR 56423. DOE published a supplemental ANOPR for clothes washers on November 19, 1998 (63 FR 64343), a NOPR on October 5, 2000 (65 FR 59550), and a final rule on January 12, 2001 revising the energy conservation standards. 66 FR 3314.

As mentioned in the ''Background'' section, EISA 2007 amended EPCA to revise the energy conservation standards for residential clothes washers by establishing a maximum water factor, effective January 1, 2011. (42 U.S.C. 6295(g)(9)) EPCA, as amended by EISA 2007, further requires that DOE publish a final rule no later than December 31, 2011, to determine whether to amend the standards in effect for clothes washers manufactured on or after January 1, 2015. (42 U.S.C. 6295(g)(9)(B)(i)).

DOE initiated the current rulemaking on August 28, 2009 by publishing a notice announcing the availability of the framework document, the ''Energy Conservation Standards Rulemaking Framework Document for Residential Clothes Washers.'' In this notice, DOE also announced a public meeting and requested public comment on the matters raised in the framework document. 74 FR 44306 (Aug. 28, 2009). The framework document described the procedural and analytical approaches that DOE anticipated using to evaluate energy conservation standards for clothes washers and identified various issues to be resolved in conducting this rulemaking. The framework document is available at *http://www1.eere.energy.gov/buildings/appliance_standards/residential/clothes_washers_framework.html*.

DOE held a public meeting on September 21, 2009, where it presented the contents of the framework document; described the analyses it planned to conduct during the rulemaking; sought comments from interested parties on these subjects; and, in general, sought to inform interested parties about, and facilitate their involvement in, the rulemaking. Interested parties discussed the following major issues at the public meeting: Test procedure revisions; product classes; technology options; approaches to the engineering, life-cycle cost, payback period and national impact analyses; efficiency levels analyzed in the engineering analysis; and the approach for estimating typical energy and water consumption. At the meeting and during the period for commenting on the framework document, DOE received many comments that helped it identify and resolve issues involved in this rulemaking.

In response to the framework document, DOE received the Joint Petition, a comment submitted by groups representing manufacturers (the Association of Home Appliance Manufacturers (AHAM), Whirlpool Corporation (Whirlpool), General Electric Company (GE), Electrolux, LG Electronics, Inc. (LG), BSH Home Appliances (BSH), Alliance Laundry Systems (ALS), Viking Range, Sub-Zero Wolf, Friedrich A/C, U-Line, Samsung, Sharp Electronics, Miele, Heat Controller, AGA Marvel, Brown Stove, Haier, Fagor America, Airwell Group, Arcelik, Fisher & Paykel, Scotsman Ice, Indesit, Kuppersbusch, Kelon, and DeLonghi); energy and environmental advocates (American Council for an Energy Efficient Economy (ACEEE), Appliance Standards Awareness Project (ASAP), Natural Resources Defense Council (NRDC), Alliance to Save Energy (ASE), Alliance for Water Efficiency (AWE), Northwest Power and Conservation Council (NPCC), and Northeast Energy Efficiency Partnerships (NEEP)); and consumer groups (Consumer Federation of America (CFA) and the National Consumer Law Center (NCLC)) (collectively, the ''Joint Petitioners''). The Joint Petitioners recommended specific energy conservation standards for residential clothes washers that, in their view, would satisfy the EPCA requirements in 42 U.S.C. 6295(o). Earthjustice submitted a comment affirming its support for the joint petition. (Earthjustice, No. 38 at p. 1). [8]

After careful consideration of the Joint Petition containing a consensus recommendation for amended energy conservation standards for residential clothes washers, the Secretary has determined that this ''Consensus Agreement'' has been submitted by interested persons who are fairly representative of relevant points of view on this matter. Congress provided some guidance within the statute itself by specifying that representatives of manufacturers of covered products, States, and efficiency advocates are relevant parties to any consensus recommendation. (42 U.S.C. 6295(p)(4)(A)) As delineated above, the Consensus Agreement was signed and submitted by a broad cross-section of the manufacturers who produce the subject products, their trade associations, and environmental, energy efficiency, and consumer advocacy organizations. Although States were not signatories to the Consensus Agreement, they did not express any opposition to it. Moreover, DOE does not read the statute as requiring absolute agreement among all interested parties before the Department may proceed with issuance of a direct final rule. By explicit language of the statute, the Secretary has discretion to determine when a joint recommendation for an energy or water conservation standard has met the requirement for representativeness (*i.e.,* ''as determined by the Secretary''). Accordingly, DOE will consider each consensus recommendation on a case-by-case basis to determine whether the submission has been made by interested persons fairly representative of relevant points of view.

Pursuant to 42 U.S.C. 6295(p)(4), the Secretary must also determine whether a jointly-submitted recommendation for an energy or water conservation standard is in accordance with 42 U.S.C. 6295(o) or 42 U.S.C. 6313(a)(6)(B), as applicable. This determination is exactly the type of analysis which DOE conducts whenever it considers potential energy conservation standards pursuant to EPCA. DOE applies the same principles to any consensus recommendations it may receive to satisfy its statutory obligation to ensure that any energy conservation standard that it adopts achieves the maximum improvement in energy efficiency that is technologically feasible and economically justified and will result in significant conservation of energy. Upon review, the Secretary determined that the Consensus Agreement submitted in the instant rulemaking comports with the standard-setting criteria set forth under 42 U.S.C. 6295(o). Accordingly, the consensus agreement levels were included as trial standard level (TSL) 3 in today's rule for residential clothes washers. The details of the efficiency levels comprising TSL 3 and the other TSLs considered for the direct final rule are discussed in section VI.A.

In sum, because the relevant criteria under 42 U.S.C. 6295(p)(4) have been satisfied, the Secretary has determined that it is appropriate to adopt amended energy conservation standards for residential clothes washers through this direct final rule.

As required by the same statutory provision, DOE is also simultaneously publishing a NOPR which proposes the identical standard levels contained in this direct final rule and is providing for a 110-day public comment period. DOE will consider whether any comment received during this comment period is sufficiently ''adverse'' as to provide a reasonable basis for withdrawal of the direct final rule and continuation of this rulemaking under the NOPR. Typical of other rulemakings, it is the substance, rather than the quantity, of comments that will ultimately determine whether a direct final rule will be withdrawn. To this end, the substance of any adverse comment(s) received will be weighed against the anticipated benefits of the Consensus Agreement and the likelihood that further consideration of the comment(s) would change the results of the rulemaking. DOE notes that to the extent an adverse comment had been previously raised and addressed in the rulemaking proceeding, such a submission will not typically provide a basis for withdrawal of a direct final rule.

3. Issues on Which DOE Seeks Comment

As stated previously, in promulgating today's direct final rule pursuant to 42 U.S.C. 6295(p)(4), DOE carefully considered the Joint Petition submitted to DOE, which contained a consensus recommendation for amended energy conservation standards for residential clothes washers. For the reasons stated in this direct final rule, the Secretary determined that the ''Consensus Agreement'' was submitted by interested persons who are fairly representative of relevant points of view on this matter. The Secretary also determined, for the reasons set forth in this direct final rule, that the standards contained in the Consensus Agreement comport with the standard-setting criteria set forth under 42 U.S.C. 6295(o). Therefore, the Secretary promulgates this direct final rule establishing the amended energy conservation standards for residential clothes washers.

As required by the same statutory provision, DOE is also simultaneously publishing a NOPR and providing for a 110-day public comment period. Should DOE determine to proceed with the NOPR, or to gather additional data for future energy conservation standards activities for residential clothes washers, DOE will consider any comments and data received on the direct final standards. Although comments are welcome on all aspects of this rulemaking, DOE is particularly interested in comments on the following:

(1) Impacts of the standards that may lessen or improve the utility or performance of the covered products. These impacts may include increased cycle times to wash clothes, ability to achieve good wash performance (*e.g.,* cleaning and rinsing), increased longevity of clothing, improved ergonomics of washer use, increase in noise, and other potential impacts.

(2) The 2015 and 2018 compliance dates for the proposed standards and whether these compliance dates adequately consider the typical clothes washer model design cycle for manufacturers.

(3) Whether repair costs for residential clothes washers would increase at the efficiency levels indicated in today's rule due to any changes in the design and materials and components used in order to comply with the new efficiency standards.

(4) Where there would be any anticipated changes in the consumption of complementary goods (*e.g.,* laundry detergent, stain removers, fabric softeners) that may result from the proposed standards.

(5) Whether DOE should incorporate the cost of risers or storage drawers (also referred to as pedestals) into the baseline installation costs for front-loading machines.

Changes in the Utility of the Products

DOE has prepared a technical support document (TSD) that analyzed the effect of this rule on, among other things, life cycle costs, payback periods and other consumer-related impacts. However, there are other facets of consumer welfare that are not explicitly captured in this analysis, including washing

[8] A notation in the form ''Earthjustice, No. 38 at p. 1'' identifies a written comment that DOE has received and has included in the docket of the standards rulemaking for residential clothes washers (Docket No. EERE–2008–BT–STD–0019). This particular notation refers to a comment (1) submitted by Earthjustice, (2) in document number 38 in the docket of that rulemaking, and (3) appearing on page 1 of document number 38.

performance, increased longevity of clothing, and noise. While information gathered in the course of this rulemaking did not demonstrate a linkage between these topics and efficiency standards, DOE is seeking comment and information on how consumers value changes in these attributes and if those values should be incorporated into DOE analysis.

Also, although it is outside the scope of this rule, DOE may consider seeking information on whether to account for wash performance and fabric care in test procedures for clothes washers.

2015 and 2018 Compliance Dates

Recognizing that this direct final rule, including the compliance dates, is based on a consensus agreement including virtually all manufacturers of residential clothes washers, DOE is seeking comment on redesign timelines anticipated by the manufacturers and how the 2015 and 2018 compliance dates may affect those timelines. DOE's manufacturer impact analysis is based on information provided by the manufacturer and supports the positions that manufacturers will need to make only minor redesign to comply with the 2015 standards, though the 2018 standards could require more substantial redesigns. Accepting that manufacturers fully considered their cost implications prior to entering voluntarily the consensus agreement, DOE assumes that manufacturers would not have agreed to compliance dates they could not meet or that imposed prohibitive costs. However, depending on how the redesign timeline and the compliance dates coincide, the cost estimates may be affected, for example, due to sunk cost, as well as the anticipated market shares of front-loading versus top-loading clothes washers.

The TSD, which is available at the rulemaking Web site at *www1.eere.energy.gov/buildings/appliance_standards/residential/clothes_washers.html,* provides an overview of the activities DOE undertook in developing standards for clothes washers. It presents and describes in detail each analysis DOE performed, including descriptions of inputs, sources, methodologies, and results. These analyses are as follows:

- A *market and technology assessment* addresses the scope of this rulemaking, identifies the clothes washer product classes, characterizes the markets for the products, and reviews techniques and approaches for improving their efficiency.
- A *screening analysis* reviews technology options to improve the efficiency of residential clothes washers and weighs those options against DOE's four prescribed screening criteria.
- An *engineering analysis* develops the relationship between increased manufacturer price and increased efficiency.
- A *markups analysis* establishes markups for converting manufacturer prices to customer product costs.
- An *energy use analysis* generates energy-use estimates for residential clothes washers as a function of efficiency levels.
- A *life-cycle cost analysis* calculates the effects of standards on individual customers and compares the life-cycle costs (LCC) and payback period (PBP) of products with and without higher efficiency standards.
- A *shipments analysis* forecasts shipments with and without higher efficiency standards.
- A *national impact analysis* forecasts the national energy savings (NES), and the national net present value of total consumer costs and savings, expected to result from specific, potential energy conservation standards for residential clothes washers.
- A *consumer subgroup analysis* discusses the effects of standards on different subgroups of consumers.
- A *manufacturer impact analysis* discusses the effects of standards on the finances and profitability of product manufacturers.
- An *employment impact analysis* discusses the indirect effects of standards on national employment.
- A *utility impact analysis* discusses the effects of standards on electric and gas utilities.
- An *emissions analysis* discusses the effects of standards on three pollutants—sulfur dioxide (SO_2), nitrogen oxides (NO_X), and mercury—as well as carbon emissions.
- A *regulatory impact analysis* discusses the impact of non-regulatory alternatives to efficiency standards.

Finally, the comments received since publication of the framework document, including the Joint Petition, have contributed to DOE's proposed resolution of the issues in this rulemaking. This direct final rule addresses these comments and responds to the issues they raised.

III. General Discussion

A. Product Classes and Scope of Coverage

When evaluating and establishing energy conservation standards, DOE divides covered products into product classes by the type of energy used or by capacity or other performance-related features that affect efficiency. Different energy conservation standards may apply to different product classes. (42 U.S.C. 6295(q))

DOE received several comments from interested parties regarding the product classes and their organization. Specifically, DOE received comments regarding the criteria used as a basis for creating product classes; the potential elimination of top-loading semiautomatic and suds-saving product classes; and whether combination washer/dryers are covered products. DOE's responses to these comments are discussed in the following sections.

Existing energy conservation standards divide residential clothes washers into five product classes based on location of access, capacity, and other features such as suds saving.

- Top-loading, compact (less than 1.6 cubic feet capacity);
- Top-loading, standard (1.6 cubic feet or greater capacity);
- Top-loading, semiautomatic;
- Front-loading; and
- Suds-saving.

AWE stated that DOE's practice of considering separate product classes should be analyzed, and that by making exceptions for old technologies by creating their own product class, DOE hinders innovation and the establishment of more progressive standards. AWE further stated that some manufacturers have already demonstrated that efficiency levels can be obtained without sacrificing performance. According to AWE, DOE should move to performance-based standards and to eliminate technology-based standards unless it can be demonstrated that the full life-cycle consumer economic impacts would favor continuation of product classes. (AWE, No. 12 at p. 2) Pursuant to 42 U.S.C. 6295(q), DOE must set different energy conservation standards for groups of covered products if such products consume a different kind of energy than other products within the same type or class, or if such products have a capacity or other performance-related feature that justifies a different standard. In determining whether a different standard is justified, EPCA requires DOE to consider utility to the consumer and any other appropriate factors. DOE is required to establish standards that achieve the maximum improvement in energy and water efficiency that is both technologically feasible and economically justified. (42 U.S.C. 6295(o)(2)(A)) As explained below, DOE has adhered to these statutory requirements in establishing the product classes in today's rulemaking.

1. Elimination of Existing Product Classes

DOE sought comment in the framework document as to whether it should retain the top-loading semi-automatic and suds-saving product classes because it is unaware of any such residential clothes washers on the market. DOE also noted that its test procedures at appendices J1 and J2 do not measure the possible energy savings associated with suds-saving because DOE is not aware of methodology to measure such savings over sequential operating cycles as necessary to capture the benefit of suds-saving. AHAM, ALS, GE, Samsung, and Whirlpool supported the elimination of top-loading semi-automatic and suds-saving product classes. (AHAM, Public Meeting Transcript, No. 7 at pp. 42, 72; [9] ALS, Public Meeting Transcript, No. 7 at p. 39; GE, Public Meeting Transcript, No. 7 at p. 41; GE, No. 20 at p. 1; [10] Samsung, No. 25 at p. 3; Whirlpool, Public Meeting Transcript, No. 7 at p. 41) AHAM, ALS, GE, and Whirlpool stated that these products are no longer available on the market. (AHAM, No. 16 at p. 3; ALS, No. 13 at p. 2; GE, No. 20 at p. 1; Whirlpool, No. 22 at p. 3) AWE stated that suds-saving is not a new or proprietary technology, but that it is starting to make a comeback. AWE further stated DOE should consider suds saving in its analysis. (AWE, No. 12 at p. 3) In its research, DOE did not identify any suds-saving residential clothes washers on the market in the United States. For this reason, and in accordance with general support among interested parties, DOE is eliminating the top-loading semi-automatic and suds-saving product classes in this final rule.

2. Product Class Differentiation by Method of Access

In the framework document, DOE also sought comment as to whether the method of loading clothes washers, or any other characteristic commonly associated with traditional top-loading or front-loading clothes washers are "features" within the meaning of 42 U.S.C. 6295(o)(4) in EPCA and whether the availability of such feature(s) would likely be affected by eliminating the separate classes for these product types previously established by DOE. More specifically, DOE invited comments on whether one or more of the characteristics commonly associated with different types of clothes washers, such as method of loading, presence or absence of agitators, ability to interrupt cycles and possibly others, provide consumer utility that should, under existing law, be recognized and protected by DOE in separate product classes.

a. Single Product Class

ACEEE, ASAP, Electrolux Home Products (EHP), NEEP, Pacific Gas and Electric Company (PG&E), and Samsung, along with PG&E, Southern California Gas Company (SCG), and Southern California Edison (SCE), jointly (hereafter "California Utilities") and ASAP, NRDC, and NCLC, jointly (hereafter, "Joint Comment" [11]), supported a single product class for all standard-size clothes washers, eliminating the differentiation based on method of loading. According to BSH, the California Utilities, Earthjustice, the Joint Comment, and NEEP, a single product class would not lessen utility or performance under EPCA. ASAP and the California Utilities commented that a single product class would not eliminate top-loaders from the market, and AWE noted that there are high efficiency top-loading clothes washers available. ASAP and the Joint Comment stated that there are at least 35 clothes washer models from four manufacturers on the current ENERGY STAR list. BSH commented that with the current differentiation between top-loading and front-loading clothes washers, consumers may assume that a high efficiency top-loader is more efficient than a "worst-in-class" front-loader if they are both ENERGY STAR rated, even though the reverse may be true. The California Utilities noted that there are currently 10–15 top-loading residential clothes washers in the California Energy Commission (CEC) database that are Consortium for Energy Efficiency (CEE) Tier 2 or better, and top-loading horizontal-axis clothes washers with efficiencies comparable to front-loading clothes washers are prevalent in some European markets. Samsung noted that utility rebates and certain energy labeling programs do not differentiate by clothes washer axis. (ACEEE, Public Meeting Transcript, No. 7 at p. 46; ASAP, Public Meeting Transcript, No. 7 at pp. 34–35, p. 45; AWE, No. 12 at p. 2; BSH, No. 11 at p. 2; California Utilities, No. 19 at pp. 1, 3; EHP, No. 18 at p. 2; Earthjustice, Public Meeting Transcript, No. 7 at p. 42; Earthjustice, No. 17 at p. 1; Joint Comment, No. 15 at p. 4; NEEP, No. 21 at pp. 1–2; PG&E, Public Meeting Transcript, No. 7 at p. 43; Samsung, No. 25 at p. 3)

According to EHP, NEEP, and Samsung, the method of access for loading clothing is not a feature that provides utility to the consumer. EHP stated that manner of access was merely a convenience. BSH commented that the vast majority of clothes washers are sold with dryers, and clothes dryers are front-loading. (BSH, No. 11 at p. 2; EHP, No. 18 at p. 2; NEEP, No. 21 at p. 1; Samsung, No. 25 at p. 3)

b. Multiple Product Classes

AHAM, ALS, and GE stated that they support the proposed product classes, which maintain the distinction between top-loading and front-loading residential clothes washers. (AHAM, No. 24 at p. 2; ALS, Public Meeting Transcript, No. 7 at p. 39; GE, No. 20 at p. 1) ALS and GE commented that "top-loading" is a feature within the meaning of EPCA, although ALS believes that "vertical-axis" and "horizontal-axis" are better terms because a horizontal-axis clothes washer can be configured to be top-loading. (ALS, No. 13 at p. 3; GE, No. 20 at p. 1)

AHAM and Whirlpool stated that multiple product classes for residential clothes washers would be consistent with classes that DOE has defined for other products. AHAM stated that multiple product classes were defined for refrigerator-freezers primarily on the basis of door placement. Whirlpool commented that multiple refrigerator-freezer classes reflect consumer choice and utility, while room air conditioner product classes also reflect consumer choice and utility as well as home configuration. (AHAM, No. 24 at p. 2; Whirlpool, No. 22 at p. 3)

GE commented that, in contrast to front-loading residential clothes washers, the vast majority of top-loading products are manufactured in the United States and provide an important source of U.S. jobs in these manufacturing locations. According to

[9] A notation in the form "AHAM, Public Meeting Transcript, No. 7 at pp. 42, 72" identifies an oral comment that DOE received during the September 21, 2009, framework public meeting and which was recorded in the public meeting transcript in the docket for the standards rulemaking for residential clothes washers (Docket No. EERE–2008–BT–STD–0019), maintained in the Resource Room of the Building Technologies Program. This particular notation refers to a comment (1) made by the Association of Home Appliance Manufacturers (AHAM) during the public meeting, (2) recorded in document number 7, which is the public meeting transcript that is filed in the docket of this rulemaking, and (3) which appears on pages 42 and 72 of document number 7.

[10] In its written comment, document number 19 in the docket of this rulemaking, GE states that it adopts by reference the comments submitted to DOE by AHAM. Thus, GE is cited alongside AHAM when discussing AHAM's written comments.

[11] The Alliance to Save Energy submitted a written comment, designated as document number 23 in the docket of this rulemaking, stating that it endorses the joint comments submitted by ASAP, NRDC, and NCLC, and requested that it be listed as a co-endorser in citation of these joint comments.

GE, the U.S. manufacturers with significant investment in these top-loading products produced domestically could be significantly disadvantaged should standards eliminate top-loaders. (GE, No. 20 at p. 3)

AHAM commented that DOE already addressed the product class issue for residential clothes washers in its denial of California's Petition for Waiver.[12] (AHAM, Public Meeting Transcript, No. 7 at p. 43)

Finally, the Joint Petition proposes energy conservations standard levels for both the top-loading and front-loading standard and compact product classes. (Joint Petition, No. 32 at 8)

c. Consumer Utility

DOE received additional comments regarding specific issues that interested parties suggested are related to consumer utility in the context of residential clothes washer product classes.

Cycle Time

AHAM, ALS, and GE stated that the longer cycle times of front-loading clothes washers support differentiation of product classes by method of access. According to ALS, cycle times longer than 85 minutes are necessary for front-loaders to achieve good wash performance, which can be achieved in a 55-minute wash cycle by a top-loader. (AHAM, No. 24 at p. 2; ALS, No. 13 at p. 4; GE, No. 20 at p. 2)

The California Utilities stated that it had conducted a preliminary survey indicating that there may not be significant differences in cycle times between top-loading and front-loading clothes washers. The Joint Comment noted that cycle times for front-loading clothes washers are becoming shorter. The California Utilities and the Joint Comment also suggested that the lower remaining moisture content (RMC) typical of front-loaders could lead to shorter clothes dryer cycle times, reducing the combined time of washing and drying a laundry load. (California Utilities, No. 19 at p. 3; Joint Comment, No. 15 at p. 4)

Mid-Cycle Access

ALS stated that garments can be added during a wash cycle in a top-loading clothes washer, but that the loading door on a front-loading clothes washer must be locked. According to ALS, the door can be unlocked mid-cycle, but it requires time and may require draining the wash water. (ALS, No. 13 at p. 4)

The California Utilities stated that many front-loading clothes washers are now equipped with a feature to unlock the door in the middle of a wash cycle. According to the Joint Comment, such a feature has been available on front-loaders for over a decade. (California Utilities, No. 19 at p. 3; Joint Comment No. 14 at p. 4)

Cost

ALS, GE, and Whirlpool stated that multiple product classes allow consumers a low-cost clothes washer option. ALS stated that purchase cost was the primary reason that top-loading residential clothes washers have maintained a majority of the market share, and that inherent differences between top-loading and front-loading designs will preclude comparable consumer cost for equivalent top-loaders and front-loaders. ALS commented that key components contributing to the added cost of front-loading clothes washers are motors, electronic controls, heavy mass weights, and door assembly costs. ALS estimated that the front-loading door feature results in a manufacturing cost differential of $250 and a consumer price differential of at least $500 when compared to a top-loading door. Also, according to ALS, consumer objections to stooping have required manufacturers to introduce pedestals for front-loading clothes washers, adding $250 to the retail price. (ALS, No. 13 at p. 3; GE, Public Meeting Transcript, No. 7 at p. 41; GE, No. 20 at p. 1; Whirlpool, No. 22 at p. 2) GE stated that a single product class would force extremely expensive technological changes on the industry. GE also commented that increased prices would have a disproportionate impact on low-income consumers who are especially sensitive to price. According to GE, these consumers may be unable to make high initial payments or obtain credit, and may choose to defer replacing older, less efficient clothes washers or to leave the home laundry market altogether. (GE, No. 20 at pp. 1, 3)

EHP commented that, in the past, manufacturers have been able to innovate to meet improved performance while maintaining cost. EHP also stated that payback in the form of lower energy and water costs would offset a higher initial cost of high efficiency top-loading clothes washers. (EHP, No. 18 at p. 2) The Joint Comment stated that high efficiency top-loading clothes washers are available on the market priced near or below $500. (Joint Comment, No. 15 at p. 4)

Consumer Preference and Market Share

According to AHAM, ALS, GE, and Whirlpool, consumer preference supports maintaining clothes washer product class distinction by method of access. ALS commented that most consumers prefer not to stoop or bend while loading clothes, which is not required for a top-loading clothes washer. GE estimated that top-loading residential clothes washers account for about 65 percent of the U.S. market. Whirlpool commented that one-third of consumers who purchased front-loaders have switched back to high-efficiency top-loaders. Whirlpool listed as contributing factors the existence of high efficiency top-loading clothes washers with better utility than front-loaders in terms of ergonomics, vibration, noise, cycle times, value proposition, sour smell, ease of use, and familiarity. Whirlpool further noted that front-loader sales have slowed even though 84 percent of consumers say energy conservation is very important to them when buying an appliance. ALS stated that it had recently received a letter from a consumer supporting Whirlpool's statement that many consumers who purchased front loaders subsequently switched back to top loaders. (AHAM, No. 24 at p. 2; ALS, Public Meeting Transcript, No. 7 at p. 45; ALS, No. 13 at pp. 2, 4; GE, No. 20 at pp. 1–2; Whirlpool, Public Meeting Transcript, No. 7 at p. 44; Whirlpool, No. 22 at pp. 2–3)

EHP stated that the means of loading is merely a convenience factor for consumers. (EHP, No. 18 at p. 2) ASAP, the California Utilities, NEEP, and PG&E commented that the growth in front-loader market share from 15 percent 5 years ago to approximately 35 percent now indicates that consumer preference for front-loading clothes washers has shifted dramatically recently. The California Utilities also stated that consumer preference research that DOE commissioned for the last residential clothes washer energy conservation rulemaking indicated that concern for axis of rotation and door placement was scored low by consumers.[13] PG&E and

[12] This comment refers to DOE's denial of the California Energy Commission's petition for waiver from Federal preemption of its residential clothes washer water conservation standards. 71 FR 78157 (Dec. 28, 2006). On October 28, 2009, for reasons unrelated to product class issues, the Ninth Circuit U.S. Court of Appeals reversed DOE's ruling and remanded CEC's petition for further review. *California Energy Comm'n* v. *DOE,* 585 F.3d 1143 (9th Cir. 2009)

[13] The CA Utilities cited the 2001 Residential Clothes Washer Final Rule TSD, Appendices I and J. Appendix J details results of consumer analysis performed to determine what clothes washer attributes consumers value most and how changes in those attributes as a result of standards would affect consumer utility and clothes washer prices. Focus group results placed axis of rotation 12th and door placement as 7th out of a list of 65 possible

the California Utilities suggested that DOE conduct an analysis of consumer preferences to assess current market conditions and trends. (ASAP, Public Meeting Transcript, No. 7 at p. 45; California Utilities, No. 19 at p. 3; NEEP, No. 21 at pp. 1–2; PG&E, Public Meeting Transcript, No. 7 at pp. 31, 43)

Other Features

GE listed larger capacity, reduced vibration, and better cleaning performance as additional utilities of top-loading residential clothes washers. (GE, No. 20 at pp. 2–3)

d. DOE Response

EPCA provides the criteria under which DOE may define classes for covered equipment:

A rule prescribing an energy conservation standard for a type (or class) of covered products shall specify a level of energy use or efficiency higher or lower than that which applies (or would apply) for such type (or class) for any group of covered products which have the same function or intended use, if the Secretary determines that covered products within such group—

(A) consume a different kind of energy from that consumed by other covered products within such type (or class); or

(B) have a capacity or other performance-related feature which other products within such type (or class) do not have and such feature justifies a higher or lower standard from that which applies (or will apply) to other products within such type (or class).

In making a determination under this paragraph concerning whether a performance-related feature justifies the establishment of a higher or lower standard, the Secretary shall consider such factors as the utility to the consumer of such a feature, and such other factors as the Secretary deems appropriate. 42 U.S.C. 6295(q)

In previous rulemakings, DOE has concluded that the method of loading clothes in washers (axis of access) is a ''feature'' within the meaning of 42 U.S.C. 6295(o)(4) and, consequently, established separate product classes for top-loading and front-loading residential clothes washers. 56 FR 22263 (May 14, 1991).

In reviewing comments submitted by interested parties in response to the framework document for the current rulemaking, DOE identified at least one consumer utility related to the method of loading clothes for residential clothes washers which represents a ''feature'' for purposes of 42 U.S.C. 6295(o)(4). Specifically, DOE believes that the longer cycle times of front-loading residential clothes washers versus cycle times for top-loaders are likely to impact consumer utility. (See chapter 5 of the direct final rule TSD.) Because the longer wash cycle times for front-loaders arise from the reduced mechanical action of agitation as compared to top-loaders, DOE believes such longer cycles may be required to achieve the necessary cleaning, and thereby constitute a performance-related utility of front-loading versus top-loading residential clothes washers pursuant to the meaning of 42 U.S.C. 6295(q).

Based on a review of residential clothes washer models currently listed in the CEC product database, DOE concludes that capacity is not a meaningful differentiator between top-loaders and front-loaders. DOE acknowledges that top-loading models from a single manufacturer achieve the highest capacity—4.3 cubic feet—but multiple front-loading models from two other manufacturers are rated at 4.1–4.2 cubic feet.

Interested parties did not submit sufficient information for DOE to evaluate the relative wash performance, vibration, noise, or odor of top-loading versus front-loading clothes washers.

DOE does not consider first cost a ''feature'' that provides consumer utility for purposes of EPCA analysis. DOE acknowledges that price is an important consideration to consumers, especially low-income purchasers, but DOE accounts for such consumer impacts in the LCC and PBP analyses conducted in support of this rulemaking.

Given the above discussion, DOE concludes that top-loading washers provide consumer utilities that, in the context of residential clothes washers, are a feature for purposes of 42 U.S.C. 6295(o)(4). Therefore, DOE retains the product class distinction between top-loading and front-loading clothes washers in this final rule.

In response to the comments related to impacts on the relative market share of top-loading versus front-loading residential clothes washers, DOE considered the cross-price elasticity of demand for top-loading and front-loading residential clothes washers in its shipments analysis. The results of this analysis are presented in chapter 9 of the direct final rule TSD.

Finally, DOE considered the impacts on manufacturers in its manufacturer impacts analysis (see chapter 12 of the direct final rule TSD).

3. Compact Product Class

ASAP, BSH, and EHP stated that DOE should consider defining a single compact product class encompassing both top-loading and front-loading clothes washers. Such a product class definition would shift front-loading compact-size clothes washers from the current front-loading product class to the existing top-loading compact product class, which would be redesignated simply as ''compact'' to eliminate the top-loading distinction. Alternatively, BSH proposed that a compact front-loading product class be defined with a capacity equal to or less than two cubic feet. BSH commented that compact-size front-loaders would have difficulty achieving the same efficiency as standard-size front-loaders, yet they provide specific utility due to their ability to fit in small living spaces in areas of high population density. AHAM and BSH noted that capacity is one of the general criteria for defining separate product classes. (ASAP, Public Meeting Transcript, No. 7 at p. 47; BSH, Public Meeting Transcript, No. 7 at p. 40; BSH, No. 11 at pp. 2, 3, 5; EHP, No. 18 at p. 2)

The Joint Petition proposes a new front-loading, compact product class and proposes energy conservations standard levels for both the top-loading and front-loading compact product classes. (Joint Petition, No. 32 at p. 8)

Based on these comments, DOE is retaining the top-loading compact product class and adding a front-loading compact product class, as proposed in the Joint Petition.

4. Product Class Summary

Table III–1 presents the product classes set forth in DOE's regulations at 10 CFR 430.32(g) and the product classes established in this rulemaking.

TABLE III–1—CLOTHES WASHER PRODUCT CLASSES

Product classes in 430.32(g)	Product classes established in this rulemaking
i. Top-loading, compact (less than 1.6 cubic feet capacity.	i. Top-loading, compact (less than 1.6 cubic feet capacity).
ii. Top-loading, standard (1.6 cubic feet or greater capacity).	ii. Top-loading, standard (1.6 cubic feet or greater capacity).
iii. Top-loading, semi-automatic.	iii. Front-loading, compact (less than 1.6 cubic feet capacity).

features. The TSD is available at *www1.eere.energy.gov/buildings/appliance_standards/residential/clothes_washers.html.*

TABLE III–1—CLOTHES WASHER PRODUCT CLASSES—Continued

Product classes in 430.32(g)	Product classes established in this rulemaking
iv. Front-loading	iv. Front-loading, standard (1.6 cubic feet or greater capacity).
v. Suds-saving.	

B. Test Procedure

As noted previously, the DOE test procedures for residential clothes washers appear at 10 CFR part 430, subpart B, appendices J1 and J2. Until the compliance date of the amended energy and water conservation standards established in today's direct final rule, absent withdrawal of the rule by DOE pursuant to 42 U.S.C. 6295(p)(4), manufacturers must use the test procedures at appendix J1 to certify compliance. Subsequently, manufacturers must use the test procedures at appendix J2.

DOE established the test procedure at appendix J2 on March 7, 2012 (77 FR 13888) to incorporate standby mode energy consumption as well as to update various active mode testing provisions. EISA 2007 amended EPCA to require DOE to amend its test procedures to integrate measures of standby mode and off mode energy consumption into the overall energy efficiency, energy consumption, or other energy descriptor for each covered product unless the current test procedure already fully accounts for and incorporates standby and off mode energy consumption or such integration is technically infeasible. (42 U.S.C. 6295(gg)(2)) In addition to incorporating standby power provisions, DOE received comments in response to the August 2009 framework document stating that it should also consider changes to the active mode provisions in the test procedure.

DOE published a notice of proposed rulemaking issued on September 21, 2010 (75 FR 57556) (hereinafter referred to as the September 2010 TP NOPR) to propose amendments regarding both standby mode and active mode provisions of the test procedure, including the following: (1) Incorporating standby and off mode power consumption into a combined energy metric; (2) addressing technologies not covered by the appendix J1 test procedure, such as steam wash cycles and self-clean cycles; (3) revising the number of annual wash cycles; (4) updating use factors; (5) revising the procedures and specifications for test cloth; (6) redefining the appropriate water fill level for the capacity measurement method; (7) establishing a new measure of water consumption; and (8) revising the definition of the energy test cycle.

The International Electrotechnical Commission (IEC) published IEC Standard 62301, ''Household electrical appliances—Measurement of standby power,'' Edition 2.0 2011–01 (IEC Standard 62301 (Second Edition)) on January 27, 2011. DOE reviewed this updated test procedure and determined that it improves the measurement of standby mode and off mode energy use compared to the previous version of the standard. Therefore, DOE published a supplemental notice of proposed rulemaking on August 9, 2011 (76 FR 49238) (hereinafter referred to as the August 2011 TP SNOPR) to integrate new measures of standby power consumption according to IEC Standard 62301 (Second Edition) and to incorporate additional amendments to the active mode provisions, including the following: (1) Revising the calculations for per-cycle energy use and annual energy cost; (2) updating the load adjustment factor; (3) clarifying the method for determining the energy test cycle; (4) clarifying the method for setting the wash time for certain clothes washers; (5) allowing the use of the most current AHAM Standard detergent; (6) clarifying the definition of ''cold wash'' for clothes washers that offer both ''cold wash'' and ''tap cold wash'' settings; and (7) performing various minor technical corrections. DOE published a second supplemental notice of proposed rulemaking on November 9, 2011 (76 FR 69870) to propose a revised definition of the energy test cycle. DOE published the final rule on March 7, 2012 (77 FR 13888), establishing the test procedure at appendix J2.

When conducting the test procedure rulemaking, DOE considered comments received on the clothes washer test procedure submitted as part of this rulemaking for energy conservation standards. In the framework document, DOE requested input on its test procedures for residential clothes washers and sought input, including supporting data, regarding how these procedures can be improved. In response to the framework document, DOE received several comments from interested parties regarding potential amendments to the DOE clothes washer test procedure to address the following issues: (1) The capacity measurement; (2) the test load size specification; (3) the energy and water use of self-clean cycles; (4) the energy and water use of steam cycles; (5) parameters representing consumer usage patterns; (6) the addition of a cleaning performance metric; (7) the remaining moisture content (RMC) measurement; (8) the measurement of standby and off mode energy use; (9) test cloth issues; (10) technical edits; and (11) anti-circumvention.

1. Capacity Measurement

DOE's clothes washer test procedure at appendix J1 states that, for measuring the capacity of the clothes washer, the clothes container shall be manually filled with water to ''its uppermost edge.'' This requirement can be interpreted in multiple ways, resulting in different capacity measurements that would each be allowable under the test procedure.

The Joint Comment stated that DOE should ensure that all data collected for this rulemaking be based on a consistent measurement of capacity, particularly because advertised capacity may be expressed using a conversion factor of 15/13 applied to the capacity measured under the DOE test procedure to approximate the capacity that would be measured using the international test standard promulgated by the IEC. The Joint Comment and Samsung stated that the measured clothes container volume can exceed the wetted space occupied by laundry by 15–20 percent or more. This could result in similar variation in MEF. The Joint Comment suggested that DOE determine whether such measurement uncertainty still exists for current vertical-axis clothes washers, and whether the capacity measurement in the test procedure should be modified for both vertical-axis and horizontal-axis clothes washers. (Joint Comment, No. 15, p. 2; Samsung, No. 25 at p. 1) ASAP commented that DOE should understand the difference between advertised capacity and the capacity that is reported to ENERGY STAR, the CEC, and other public databases, because the advertised capacity is typically larger than the reported values. (ASAP, Public Meeting Transcript, No. 7 at p. 20)

ALS commented that the test procedure should be revised to clarify that, for vertical-axis clothes washers, the ''uppermost edge'' would refer to the ''top of the tub cover.'' (ALS, Public Meeting Transcript, No. 7 at p. 22; ALS, No. 13 at p. 1) Samsung commented that there are various interpretations of what constitutes the usable volume and how the capacity is measured on vertical-axis clothes washers. According to Samsung, one such interpretation is to measure the volume to the top of the tub cover, even though the user is instructed to load to below the tub cover in a typical use and care guide. Samsung estimates that loading to the top of the tub cover could result in a 15–20 percent increase in the capacity measurement of vertical-axis clothes washers (compared to loading to the level recommended in the use and care guide), which would also overstate the MEF and WF of the unit by 15–20 percent. Therefore, Samsung proposed possible language to clarify the capacity measurement in DOE's clothes washer test procedure based on wording from IEC Standard 60456, ''Clothes washing machines for household use—Methods for measuring the performance,'' (IEC Standard 60456) Edition 5, Committee Draft for Vote (FDIS). The fill level in the DOE test procedure would thus be defined as the ''uppermost edge which may be used to fill in clothes, respecting manufacturer instructions.'' (Samsung, No. 25 at p. 1)

BSH commented that a volumetric capacity metric is misleading when comparing conventional vertical-axis, high efficiency vertical-axis, and horizontal-axis clothes washers because more volume does not necessarily correspond with more load capacity. Performance should be related to load size rather than drum volume for consumer comparisons. (BSH, No. 11 at p. 2)

DOE recognizes that the clothes container capacity measurement in appendix J1 could be interpreted in multiple ways. To provide manufacturers with additional guidance prior to issuance of the March 2012 TP final rule, DOE issued an interpretive rule on July 26, 2010. In the interpretive rule, DOE provided clarifications to the methods for measuring clothes container capacity for both top-loading and front-loading clothes washers using the appendix J1 test procedure. This interpretive rule can be found on DOE's Web site at: *www1.eere.energy.gov/buildings/appliance_standards/residential/pdfs/cw_guidance_faq.pdf*.

In the March 2012 TP final rule, DOE established a different capacity measurement procedure at appendix J2 to provide for a clearer, more consistent and more easily repeatable measurement. Under appendix J1, DOE's guidance document instructs manufacturers to measure the fill level for top-loading clothes washers at the innermost diameter of the tub cover (defined as ''Fill Level 3'' in the guidance). For the reasons discussed in the March 2012 TP final rule, the revision to the capacity measurement in appendix J2 requires manufacturers to measure the fill level for top-loading clothes washers to the uppermost edge of the rotating portion of the basket, including the balance ring (defined as ''Fill Level 2'' in DOE's interpretive guidance).

For front-loaders, under both appendix J1 and appendix J2, the fill level must not exceed the highest point of contact between the door and the door seal, excluding any portion of the door or door seal that would occupy the measured volume space when the door is closed. This is consistent with the instructions provided for front-loaders in DOE's guidance document.

DOE used the revised capacity measurement for top-loaders in determining the conversion formulas from MEF to IMEF and WF to IWF in today's final rule. For more details of the testing and analysis, see chapter 5 of the direct final rule TSD.

DOE notes that the FTC promulgates labeling requirements for residential clothes washers, which would govern marketing claims made by the manufacturer regarding capacity.

2. Test Load Size

Table 5.1 of the DOE clothes washer test procedure specifies test cloth load sizes necessary to conduct the energy cycles. Minimum, maximum, and average load sizes are defined as a function of clothes washer capacity. Currently, the maximum load size provided in the table is 3.80 cubic feet (ft^3). No provision exists for determining load size if capacity exceeds that limit. 10 CFR 430 subpart B appendix J1.

AHAM, ALS, GE and Whirlpool support a linear extension of the load size table to larger capacities. AHAM, GE, and Whirlpool recommend extending the table for capacities up to 6.0 ft^3. Whirlpool noted that DOE granted a waiver which extended the table to a capacity of 4.1 ft^3, and ALS stated it agreed with this waiver. (AHAM, Public Meeting Transcript, No. 7 at p. 21; AHAM, No. 16 at p. 2; ALS, No. 13 at p. 1; GE, No. 20 at p. 1; Whirlpool, No. 22 at p. 1) The Joint Comment objected to the extension of Table 5.1 to a capacity of 6 ft^3 without verifying the validity of the resulting load sizes with current consumer data. (Joint Comment, No. 15 at pp. 1–2)

DOE reviewed current residential clothes washer product databases from sources such as CEC and ENERGY STAR, and observed reported capacities as large as 4.7 ft^3. In response to comments received in response to the September 2010 TP NOPR, DOE extended Table 5.1 in the amended test procedure to include capacities up to 6.0 ft^3 to accommodate additional increases in capacity expected in the future. As described fully in the September 2010 TP NOPR and March 2012 TP final rule, DOE determined that the linear relationship between test load size and container capacity in appendix J1 is valid, and therefore used the same linear relationship to extend Table 5.1 to 6.0 ft^3. (17 FR 13888)

3. Self Clean Cycles

DOE's clothes washer test procedure specifies energy test cycles, the energy and water use of which are averaged to calculate the MEF and WF of the unit under consideration. These energy test cycles are selected from among various cycle settings provided by the manufacturer for laundering clothing. They do not include any cycles or pre-set settings provided for the purpose of cleaning, sanitizing, or deodorizing any of the clothes washer components. DOE observed in its test sample of units for the preliminary analysis that a dedicated self-clean function is a prevalent feature, found in virtually all front-loading clothes washers and in certain top-loading models as well.

ASAP and the Joint Comment stated that the measurement of MEF and WF should account for the energy and water use of self-clean cycles. The Joint Comment further stated that such a measurement would provide not only a more accurate assessment of machine efficiency, but also a benefit to those clothes washer designs that address mold and odor issues without requiring periodic sanitizing cycles. (ASAP, Public Meeting Transcript, No. 7 at p. 19; Joint Comment, No. 15 at p. 3)

In the September 2010 TP NOPR, DOE proposed a usage factor of 12 annual self-clean cycles for incorporating the energy used in self-clean cycles. DOE based its usage factor on typical manufacturer instructions that recommend using this feature once each month. DOE received comments stating that consumer usage data on self-clean cycles was insufficient to validate the usage factors it proposed in the test procedure NOPR. In addition, there is uncertainty as to whether a self-clean cycle should be tested only if it is a specific feature provided by the manufacturer, or if a conventional cycle that the manufacturer recommends the consumer to run periodically for the purpose of cleaning or sanitizing the clothes washer should also be tested as a self-clean cycle. Finally, DOE is concerned about the increased test burden required for testing self-clean cycles given the relatively small amount of annual energy used in these periodic cycles. For these reasons, DOE did not include the energy and water use of self-clean cycles in the modified test procedure.

4. Steam Cycles

The energy test cycles specified in the DOE clothes washer test procedure do not include provisions for testing any cycles incorporating steam injection. DOE is aware of a number of clothes washers available on the market that offer a steam feature as either a stand-alone cycle or as an add-on to a traditional wash cycle. DOE notes that steam features are available on primarily some higher-end front-loading clothes washers.

ASAP and the Joint Comment stated that DOE should amend the test procedure to account for the impact of steam cycle use. (ASAP, Public Meeting Transcript, No. 7 at p. 19; Joint Comment, No. 15 at p. 3)

In the September 2010 TP NOPR, DOE proposed a temperature usage factor of 0.02 to incorporate the energy used in steam cycles. DOE believed that extra hot and steam cycles would be reserved for the most heavily soiled loads, and would have similar use factors. DOE assumed that the steam wash cycles would be selected somewhat fewer times than the extra hot cycle because on some models steam is available only as an option on certain settings. DOE received comments stating that consumer usage data on steam cycles is insufficient to validate the temperature usage factors it proposed in the September 2010 TP NOPR. Furthermore, DOE notes that because there is significant variation in how individual manufacturers implement steam features, creating a universal definition of a steam cycle for the energy test cycle would be difficult. Finally, DOE is concerned about the increased test burden required for testing steam cycles given the relatively small amount of annual energy used in these cycles. For these reasons, DOE did not include the energy and water use of steam cycles in the modified test procedure.

5. Consumer Usage Patterns

Various factors are provided in the DOE clothes washer test procedure to properly account for consumer usage patterns, including the number of use cycles per year, selection of load sizes, selection of temperature settings, and the percentage of washed clothes loads that are dried in a clothes dryer.

ALS supported reducing annual usage to 300 cycles, based on Procter & Gamble consumer studies. The Joint Comment stated DOE should collect data on current consumer laundry usage to validate or update the cycles per year, estimates of ''average'' load size among clothes washers of varying capacities, annual load size usage factors, temperature use factors, and dryer use factor. The Joint Comment stated that DOE should ensure that there is no systematic bias in these factors favoring larger capacities. The Joint Comment also requested that DOE reassess the load adjustment factor, which was established in the 1990s. (ALS, No. 13 at p. 1; Joint Comment, No. 15 at pp. 1–3)

In the March 2012 TP final rule, DOE reduced the number of annual cycles to 295 based on a survey of available consumer usage data and comments received from interested parties. DOE increased the dryer usage factor to 0.91 based on the most recent consumer survey data available.

DOE is unaware of any updated consumer usage data regarding load sizes among clothes washers of varying capacities and load size usage factors. Therefore, DOE did not amend the load usage factors or the linear relationship used to determine load size based on clothes washer capacity in the modified test procedure. Similarly, DOE did not identify any evidence that suggests any unwarranted bias in favor or larger capacities in the test procedure.

DOE received additional information from commenters regarding temperature use factors (TUFs). The information received contained significant disparities, however, and no information supporting particular TUFs was more persuasive or reliable than information supporting other TUFs. Therefore, the information provided no basis upon which to change the TUF values in the appendix J1 test procedure, and DOE retained these TUFs in appendix J2. DOE did, however, establish a new TUF for a full warm wash/warm rinse cycle and eliminated the incremental use factor attributed to warm rinse in appendix J1.

Finally, DOE determined that the load adjustment factor (LAF) is duplicative of, yet inconsistent with, the load usage factors. Therefore, for consistency with the rest of the test procedure, DOE amended the representative load size calculation in the equation for drying energy to incorporate the load usage factors rather than a separate LAF. DOE replaced the LAF with a weighted-average load size, calculated by multiplying the minimum, average, and maximum load usage factors by the minimum, average, and maximum load sizes, respectively, and summing the products.

6. Standard Extractor RMC Test Procedure

The DOE test procedure contains provisions for evaluating the moisture absorption and retention characteristics of a lot of test cloth by measuring the RMC in a standard extractor at a specified set of conditions.

AHAM submitted detailed recommendations of changes to the methodology used for the Standard Extractor RMC Test Procedure included in the overall clothes washer test procedure. Whirlpool and GE stated that they support AHAM's recommendations. (AHAM, Public Meeting Transcript, No. 7 at p. 21; AHAM, No. 16 at p. 2; GE, No. 20 at p. 1; Whirlpool, No. 22 at p. 1) DOE largely agrees with AHAM's recommendations and implemented many of them in the revised test procedure.

7. Performance Metric

DOE's clothes washer test procedure provides a measure of representative energy and water use. It does not evaluate cleaning or rinsing performance or fabric care. AHAM, BSH, GE, and Whirlpool commented that DOE should add a performance measure, particularly because at the higher efficiency levels, clothes washers are reaching the limit where product performance and consumer satisfaction may not be economically reached. AHAM noted that its clothes washer standard, ANSI/AHAM HLW–1–2007, ''Performance Evaluation Procedures for Household Clothes Washers,'' addresses performance and is substantially harmonized with IEC Standard 60456. Whirlpool also noted that ANSI/AHAM HLW–1–2007 provides performance measurement. ALS and BSH also recommended review of IEC Standard 60456 for methods of assessing performance, and ALS recommended review of the Australian standard AS/NZS 2040.1. (AHAM, No. 16 at p. 2; ALS, No. 13 at p. 2; BSH, No. 11 at p. 2; GE, No. 20 at p. 1; Whirlpool, No. 22 at p. 2) ALS stated it had not yet determined whether it would support a performance metric, or what a measurement method for measuring performance would be, although it added that it is concerned that energy conservation standards have reached the point where higher levels will cause unacceptable performance, especially for vertical-axis top-loaders. (ALS, No. 13 at p. 1)

DOE test procedures must be reasonably designed to produce test results that measure energy efficiency, energy use, water use in specified instances, or estimated annual operating cost of a covered product during a representative use cycle or period of use. 42 U.S.C. 6293(b)(3). DOE notes that the measurement of energy efficiency or energy or water use presumes the proper functioning of a product. DOE considers utility in setting energy conservation standards, and DOE may not prescribe a standard that is likely to result in the unavailability in the United States of performance characteristics, including reliability. 42 U.S.C. 6295(o)(2)(B)(i)(IV), (o)(4) DOE has considered performance generally in the development of these standards and does not believe that the standards established in today's final rule would adversely impact the utility of residential clothes washers.

8. Standby Power

In the framework document, DOE noted that it considered incorporating certain provisions of IEC Standard 62301, ''Household electrical appliances–Measurement of standby power'', First Edition 2005–06 (IEC Standard 62301 (First Edition)) in accordance with requirements of EISA 2007. DOE further noted that it would consider an updated version of IEC Standard 62301 in its residential clothes washer test procedure rulemaking. In response to the framework document, DOE received comments regarding the inclusion of standby and off mode power consumption in its clothes washer test procedure and its consideration of the updated version of IEC Standard 62301.

ALS commented that it supports revising the test procedure to add provisions for measuring standby power. (ALS, No. 13, No. 1) The California Utilities stated that DOE should make a determination of the metrics that it will use for clothes washer energy conservation standards, because if standby and off mode power is incorporated, MEF might not be used to regulate clothes washers in this rulemaking. According to the California Utilities, it would be detrimental to proceed with the preliminary analysis without finalizing possible changes to the metric. (California Utilities, No. 19 at p. 1) Whirlpool stated that standby power should be incorporated into MEF, rather than addressed as a separate metric. (Whirlpool, No. 22 at p. 2) ASAP, the California Utilities, the Joint Comment, and NEEP urged DOE to proceed with the clothes washer test procedure rulemaking without waiting further for the release of an updated version of IEC Standard 62301. (ASAP, Public Meeting Transcript, No. 7 at p. 18; California Utilities, No. 19 at p. 1; Joint Comment, No. 15 at p. 1; NEEP, No. 21 at p. 1) ASAP also commented that the mode definitions in IEC Standard 62301 are not necessarily comparable to DOE's statutory mode definitions, and that it may not be advisable to use the IEC definitions. (ASAP, Public Meeting, No. 7 at p. 19)

In the September 2010 TP NOPR, DOE proposed to incorporate by reference into the clothes washer test procedure specific provisions from IEC Standard 62301 (First Edition) regarding test conditions and test procedures for measuring standby mode and off mode power consumption. DOE also proposed to adopt certain provisions from the IEC Standard 62301 Committee Draft for Vote (CDV) version (an earlier draft version of the IEC 62301 revision), as well as the Final Draft International Standard (FDIS) version (the draft version developed just prior to the issuance of the Second Edition). Specifically, DOE proposed to adopt the 30-minute stabilization and 10-minute measurement periods as described in the CDV version and the mode definitions for active, standby and off mode as described in the FDIS version.

In the August 2011 TP SNOPR, DOE evaluated IEC Standard 62301 (Second Edition) and concluded that the application of the provisions of the Second Edition to all power measurements in standby mode and off mode for clothes washers would be an improvement over the First Edition and would not be unduly burdensome to conduct. Therefore, DOE proposed incorporating by reference the relevant paragraphs of section 4 and section 5 of IEC Standard 62301 (Second Edition) in the clothes washer test procedure.

In the March 2012 TP final rule, DOE incorporated by reference the relevant paragraphs of section 4 and section 5 of IEC Standard 62301 (Second Edition) in the clothes washer test procedure. DOE integrated standby and off mode energy use into its revised clothes washer test procedure by establishing an IMEF metric based on measurements made according to certain provisions of this updated IEC standard. 77 FR 13888. Accordingly, DOE based its analysis for clothes washer energy conservation standards in today's direct final rule on this IMEF metric.

DOE notes that AHAM provided a related comment in response to the Request for Information (RFI) issued by DOE to implement Executive Order 13563, ''Improving Regulation and Regulatory Review (76 FR 6123, Feb. 3, 2011), opposing any test procedure requirement to measure separately the energy use of delay start and cycle finished modes.[14] AHAM stated that the additional burden that would be required to measure a de minimis amount of energy would not be justified. (AHAM, IRRR, No. 10 at pp. 5–6) [15]

Based on the results of the data presented in the August 2011 TP SNOPR, DOE believes that including a specific measurement of energy use of a cycle finished feature that incorporates intermittent tumbling and air circulation would not significantly impact the total annual energy consumption. Furthermore, measuring the energy use over the entire duration of cycle finished mode would increase the test duration by up to 10 hours, depending on the maximum duration of cycle finished mode provided on the clothes washer under test. DOE believes this would represent a significant increase in test burden that would not be warranted by the minimal additional energy use captured by measuring cycle finished mode separately or as part of the active washing mode.

Therefore, in the March 2012 TP final rule, DOE did not adopt provisions to measure cycle finished mode separately or as part of the active washing mode. DOE believes that measuring power consumption of each mode separately would introduce significant test burden without a corresponding improvement in a representative measure of annual energy use. Therefore, DOE provided in the March 2012 TP final rule for measuring total energy consumption, in which all low-power mode hours are allocated to the inactive and off modes, and the low-power mode power consumption is measured only in the inactive and off modes, depending on which of these modes is present.

9. Test Cloth

Different lots of energy test cloth used in the clothes washer test procedure are released to the industry at least once a year, and the properties of the test cloth must be measured and standardized against reference historical lots. AHAM and ALS support revisions to the clothes washer test procedure for improving the process to correlate new test cloth batches to the historical lots. AHAM provided a proposal for an industry-developed auditing program, as well as suggested specifications for test cloth tolerances. GE supports this

[14] Definitions of operating modes, including cycle finished, delayed start, active washing, inactive, and off modes, are provided in the March 2012 TP final rule. 77 FR 13888.

[15] The notation in the form ''AHAM, IRRR, No. 10 at pp. 5–6'' identifies a written comment that DOE has received and has included in the docket of the Request for Information (RFI) to implement Executive Order 13563, ''Improving Regulation and Regulatory Review (76 FR 6123, Feb. 3, 2011). (Docket No. DOE–HQ–2011–0014). This particular notation refers to a comment (1) submitted by Association of Home Appliance Manufacturers (AHAM), (2) in document number 10 in the docket of that RFI, and (3) appearing on pages 5–6 of document number 10.

proposal. (AHAM, Public Meeting Transcript, No. 7 at pp. 21–22; AHAM, No. 16 at p. 2; ALS, No. 13 at p. 1; GE, No. 20 at p. 1) Whirlpool noted that the test cloth is currently available from one supplier that has limited capability to meet industry's needs. Whirlpool suggested that DOE assume responsibility for test cloth procurement and qualification. (Whirlpool, No. 22 at p. 1) DOE is currently working with industry, suppliers, and test laboratories to develop an auditing program that meets industry's needs. Qualification tests are being conducted at an independent test laboratory as well as at DOE's Appliance Testing and Evaluation Center (ATEC).

10. Technical Edits

AHAM and GE suggested that DOE remove obsolete sections of the clothes washer test procedure in guidelines that AHAM submitted to DOE on September 22, 2008. (AHAM, Public Meeting Transcript, No. 7 at p. 21; AHAM, No. 16 at p. 2; GE, No. 20 at p. 1) DOE agreed with these suggestions and removed the obsolete provisions in the revised test procedure as part of the residential clothes washer test procedure rulemaking.

11. Anti-Circumvention

EPCA requires that test procedures be reasonably designed to produce test results which measure energy efficiency, energy use, water use or estimated annual operating cost of a covered product during a representative average use cycle or period of use, as determined by the Secretary. 42 U.S.C. 6293(b)(3). This statutory requirement may be undermined if products are purposefully designed to use controls or features that produce test results that are so unrepresentative of a product's actual energy or water consumption as to provide materially inaccurate comparative data. The Joint Comment stated that DOE should ensure that the test procedure is not vulnerable to circumvention and should prohibit any mode or other operating function that is designed solely or primarily to reduce energy and water consumption during testing. According to the Joint Comment, sophisticated and inexpensive electronic controls may detect the DOE testing conditions and minimize energy and water use under those specific conditions. The Joint Comment described as an illustrative example a clothes washer with adaptive fill control that could be programmed to minimize the fill level when it measured a clothes load size at exactly the weight of the average DOE test load for that capacity machine. (Joint Comment, No. 15 at p. 3) DOE considered issues of circumvention in its clothes washer test procedure rulemaking.

C. Technological Feasibility

1. General

In each standards rulemaking, DOE conducts a screening analysis based on information gathered on all current technology options and prototype designs that could improve the efficiency of the products or equipment that are the subject of the rulemaking. As the first step in such an analysis, DOE develops a list of technology options for consideration in consultation with manufacturers, design engineers, and other interested parties. DOE then determines which of those means for improving efficiency are technologically feasible. DOE considers technologies incorporated in commercially available products or in working prototypes to be technologically feasible. 10 CFR 430, subpart C, appendix A, section 4(a)(4)(i).

After DOE has determined that particular technology options are technologically feasible, it further evaluates each technology option in light of the following additional screening criteria: (1) Practicability to manufacture, install, or service; (2) adverse impacts on product utility or availability; and (3) adverse impacts on health or safety. Section IV.B of this notice discusses the results of the screening analysis for residential clothes washers, particularly the designs DOE considered, those it screened out, and those that are the basis for the efficiency levels considered in this rulemaking. For further details on the screening analysis for this rulemaking, see chapter 4 of the direct final rule TSD.

2. Maximum Technologically Feasible Levels

When DOE proposes to adopt an amended standard for a type or class of covered product, it must determine the maximum improvement in energy efficiency or maximum reduction in energy use that is technologically feasible for such product. (42 U.S.C. 6295(p)(1)) Accordingly, in the engineering analysis DOE determined the maximum technologically feasible (''max-tech'') improvements in energy efficiency for residential clothes washers, using the design parameters that lead to the creation of the most efficient products available on the market or in working prototypes. (See chapter 5 of the direct final rule TSD.) The max-tech levels that DOE determined for this rulemaking are described in section IV.C.4 of this final rule.

D. Energy Savings

1. Determination of Savings

DOE used its national impact analysis (NIA) spreadsheet model to estimate energy savings from amended standards for the products that are the subject of this rulemaking.[16] For each TSL, DOE forecasted energy savings beginning in 2015, the year that manufacturers would be required to comply with amended standards, and ending in 2044. DOE quantified the energy savings attributable to each TSL as the difference in energy consumption between the standards case and the base case. The base case represents the forecast of energy consumption in the absence of amended mandatory efficiency standards, and considers market demand for more efficient products.

The NIA spreadsheet model calculates the electricity savings in site energy expressed in kilowatt-hours (kWh). Site energy is the energy directly consumed by appliances at the locations where they are used. DOE reports national energy savings on an annual basis in terms of the aggregated source (primary) energy savings, which is the savings in the energy that is used to generate and transmit the site energy. (See chapter 10 of the direct final rule TSD). To convert site energy to source energy, DOE derived annual conversion factors from the model used to prepare the Energy Information Administration's (EIA) *Annual Energy Outlook 2010* (*AEO2010*).

2. Significance of Savings

As noted above, 42 U.S.C. 6295(o)(3)(B) prevents DOE from adopting a standard for a covered product unless such standard would result in ''significant'' energy savings. Although the term ''significant'' is not defined in the Act, the U.S. Court of Appeals, in *Natural Resources Defense Council* v. *Herrington,* 768 F.2d 1355, 1373 (D.C. Cir. 1985), indicated that Congress intended ''significant'' energy savings in this context to be savings that were not ''genuinely trivial.'' The energy savings for all of the TSLs considered in this rulemaking are nontrivial, and, therefore, DOE considers them ''significant'' within the meaning of section 325 of EPCA.

[16] The NIA spreadsheet model is described in section IV.G of this notice.

E. Economic Justification

1. Specific Criteria

As noted in section II.A, EPCA provides seven factors to be evaluated in determining whether a potential energy conservation standard is economically justified. (42 U.S.C. 6295(o)(2)(B)(i)) The following sections discuss how DOE has addressed each of those seven factors in this rulemaking.

a. Economic Impact on Manufacturers and Consumers

In determining the impacts of an amended standard on manufacturers, DOE first uses an annual cash-flow approach to determine the quantitative impacts. This step includes both a short-term assessment—based on the cost and capital requirements during the period between when a regulation is issued and when entities must comply with the regulation—and a long-term assessment over a 30-year analysis period. The industry-wide impacts analyzed include industry net present value (INPV), which values the industry on the basis of expected future cash flows, cash flows by year, changes in revenue and income, and other measures of impact, as appropriate. Second, DOE analyzes and reports the impacts on different types of manufacturers, including impacts on small manufacturers. Third, DOE considers the impact of standards on domestic manufacturer employment and manufacturing capacity, as well as the potential for standards to result in plant closures and loss of capital investment. Finally, DOE takes into account cumulative impacts of various DOE regulations and other regulatory requirements on manufacturers.

For individual consumers, measures of economic impact include the changes in life-cycle cost (LCC) and payback period (PBP) associated with new or amended standards. The LCC, which is specified separately in EPCA as one of the seven factors to be considered in determining the economic justification for a new or amended standard, 42 U.S.C. 6295(o)(2)(B)(i)(II), is discussed in the following section. For consumers in the aggregate, DOE also calculates the national net present value of the economic impacts throughout the forecast period applicable to a particular rulemaking.

b. Life-Cycle Costs

The LCC is the sum of the purchase price of a product (including its installation) and the operating expense (including energy, maintenance, and repair expenditures) discounted over the lifetime of the product. The LCC savings for the considered efficiency levels are calculated relative to a base case that reflects likely trends in the absence of amended standards. The LCC analysis requires a variety of inputs, such as product prices, product energy consumption, energy prices, maintenance and repair costs, product lifetime, and consumer discount rates. In its analysis, DOE assumed that consumers will purchase the considered products in 2015.

To account for uncertainty and variability in specific inputs, such as product lifetime and discount rate, DOE uses a distribution of values, with probabilities attached to each value. A distinct advantage of this approach is that DOE can identify the percentage of consumers estimated to receive LCC savings or experience an LCC increase, in addition to the average LCC savings associated with a particular standard level. In addition to identifying ranges of impacts, DOE evaluates the LCC impacts of potential standards on identifiable subgroups of consumers that may be affected disproportionately by a national standard.

c. Energy Savings

Although significant conservation of energy is a separate statutory requirement for imposing an energy conservation standard, EPCA requires DOE, in determining the economic justification of a standard, to consider the total projected energy savings that are expected to result directly from the standard. (42 U.S.C. 6295(o)(2)(B)(i)(III)) DOE uses the NIA spreadsheet results in its consideration of total projected energy savings.

d. Lessening of Utility or Performance of Products

In establishing classes of products, and in evaluating design options and the impact of potential standard levels, DOE sought to develop standards for residential clothes washers that would not lessen the utility or performance of those products. (42 U.S.C. 6295(o)(2)(B)(i)(IV)) DOE believes that the TSLs adopted in today's direct final rule would not reduce the utility or performance of the clothes washers under consideration in this rulemaking.

e. Impact of Any Lessening of Competition

EPCA directs DOE to consider any lessening of competition that is likely to result from standards. It also directs the Attorney General of the United States (Attorney General) to determine the impact, if any, of any lessening of competition likely to result from a proposed standard and to transmit such determination to the Secretary within 60 days of the publication of a direct final rule, together with an analysis of the nature and extent of the impact. (42 U.S.C. 6295(o)(2)(B)(i)(V) and (B)(ii)) DOE published a NOPR containing energy conservation standards identical to those set forth in today's direct final rule and transmitted a copy of today's direct final rule and the accompanying TSD to the Attorney General, requesting that the Department of Justice (DOJ) provide its determination on this issue. DOE will consider DOJ's comments on the rule in determining whether to proceed with the direct final rule. DOE will also publish and respond to DOJ's comments in the **Federal Register** in a separate notice.

f. Need for National Energy Conservation

The energy savings from new or amended standards are likely to provide improvements to the security and reliability of the nation's energy system. Reductions in the demand for electricity also may result in reduced costs for maintaining the reliability of the nation's electricity system. DOE conducts a utility impact analysis to estimate how standards may affect the nation's needed power generation capacity.

Energy savings from the proposed standards also are likely to result in environmental benefits in the form of reduced emissions of air pollutants and greenhouse gases associated with energy production. DOE reports the environmental effects from today's standards, and from each TSL it considered, in the emissions analysis contained in chapter 15 in the direct final rule TSD and in section V.B.6 of this notice. DOE also reports estimates of the economic value of emissions reductions resulting from the considered TSLs.

g. Other Factors

EPCA allows the Secretary of Energy, in determining whether a standard is economically justified, to consider any other factors that the Secretary deems to be relevant. (42 U.S.C. 6295(o)(2)(B)(i)(VII)) In developing this direct final rule, DOE has also considered the submission of the Joint Petition, which DOE believes sets forth a statement by interested persons that are fairly representative of relevant points of view (including representatives of manufacturers of covered products, States, and efficiency advocates) and contains recommendations with respect to an energy conservation standard that are in accordance with 42 U.S.C. 6295(o). DOE has encouraged the submission of consensus agreements as a way to bring diverse interested parties together, to develop an independent and probative analysis useful in DOE standard setting, and to expedite the rulemaking process. DOE also believes that standard levels recommended in the consensus agreement may increase the likelihood for regulatory compliance, while decreasing the risk of litigation.

2. Rebuttable Presumption

As set forth in 42 U.S.C. 6295(o)(2)(B)(iii), EPCA creates a rebuttable presumption that an energy conservation standard is economically justified if the additional cost to the consumer of a product that meets the standard is less than three times the value of the first year's energy savings resulting from the standard, as calculated under the applicable DOE test procedure. DOE's LCC and PBP analyses generate values used to calculate the effect potential amended energy conservation standards would have on the payback period for consumers. These analyses include, but are not limited to, the 3-year payback period contemplated under the rebuttable-presumption test. In addition, DOE routinely conducts an economic analysis that considers the full range of impacts to consumers, manufacturers, the nation, and the environment, as required under 42 U.S.C. 6295(o)(2)(B)(i). The results of this analysis serve as the basis for DOE's evaluation of the economic justification for a potential standard level (thereby supporting or rebutting the results of any preliminary determination of economic justification). The rebuttable presumption payback calculation is discussed in section IV.F.11 of this direct final rule and chapter 8 of the direct final rule TSD.

IV. Methodology and Discussion

DOE used two spreadsheet tools to estimate the impact of today's direct final rule. The first spreadsheet calculates LCCs and PBPs of potential new energy conservation standards. The second provides shipments forecasts and then calculates impacts of potential energy conservation standards on national energy savings and net present value. The two spreadsheets are available online at: *http://www1.eere.energy.gov/buildings/appliance_standards/residential/clothes_washers.html.* The Department also assessed manufacturer impacts, largely through use of the Government Regulatory Impact Model (GRIM).

Additionally, DOE estimated the impacts on utilities and the environment of energy conservation standards for residential clothes washers. DOE used a version of EIA's National Energy Modeling System (NEMS) for the utility and environmental analyses. The NEMS model simulates the energy sector of the U.S. economy. EIA uses NEMS to prepare its *Annual Energy Outlook,* a widely known baseline energy forecast for the United States. For more information on NEMS, refer to *The National Energy Modeling System: An Overview,* DOE/EIA–0581 (98) (Feb. 1998), available at: *http://tonto.eia.doe.gov/FTPROOT/forecasting/058198.pdf.*

The version of NEMS used for appliance standards analysis, which makes minor modifications to the *AEO* version, is called NEMS–BT.[17] NEMS–BT offers a sophisticated picture of the effect of standards, because it accounts for the interactions among the various energy supply and demand sectors and the economy as a whole.

A. Market and Technology Assessment

1. General

When beginning an energy conservation standards rulemaking, DOE develops information that provides an overall picture of the market for the products concerned, including the purpose of the products, the industry structure, and market characteristics. This activity includes both quantitative and qualitative assessments based primarily on publicly available information. The subjects addressed in the market and technology assessment for this rulemaking include products covered by the rulemaking, quantities and types of products sold and offered for sale, retail market trends, product classes and manufacturers, regulatory and non-regulatory programs, and technology options that could improve the energy efficiency of the product(s) under examination. See chapter 3 of the direct final rule TSD for further discussion of the market and technology assessment.

2. Products Included in This Rulemaking

This subsection addresses whether EPCA covers certain products and thereby authorizes DOE to adopt standards for those products, and whether DOE will consider in this rulemaking standards for certain products that DOE determined are covered under EPCA.

ASAP questioned whether combination washer/dryers are covered products in this rulemaking. (ASAP, Public Meeting Transcript, No. 7 at p. 47) ''Clothes washer'' is defined in 10 CFR 430.2 to mean a consumer product designed to clean clothes using a water solution of soap or detergent and mechanical agitation or other movement. A combination washer/dryer meets this definition and also performs a drying function. As a result, DOE determined that combination washer/dryers are covered products according to the existing regulatory definition of clothes washer. DOE notes that combination washer/dryers are currently being testing by certain manufacturers according to the DOE clothes washer test procedure and that certification data is available for such products in, among others, the CEC and ENERGY STAR product databases. DOE also does not have information that would indicate that, while operating in clothes washer mode, the energy and water use of such a machine is inherently different from the energy and water use of a stand-alone clothes washer.

3. Product Classes

Existing energy conservation standards divide residential clothes washers into five product classes based on location of access, capacity, and features such as suds saving. As mentioned previously in section III.A.1 DOE is not maintaining the top-loading semiautomatic and suds-saving product classes. DOE is also splitting the front-loading product class into two separate product classes based on capacity. Table IV–1 presents the product classes set forth in 10 CFR 430.32(g) and the product classes established in this rulemaking.

TABLE IV–1—CLOTHES WASHER PRODUCT CLASSES

Product Classes in 430.32(g)	Product classes established in this rulemaking
i. Top-loading, compact (less than 1.6 cubic feet capacity).	i. Top-loading, compact (less than 1.6 cubic feet capacity).
ii. Top-loading, standard (1.6 cubic feet or greater capacity).	ii. Top-loading, standard (1.6 cubic feet or greater capacity).
iii. Top-loading, semi-automatic.	iii. Front-loading, compact (less than 1.6 cubic feet capacity).

[17] EIA approves the use of the name ''NEMS'' to describe only an AEO version of the model without any modification to code or data. Because the present analysis entails some minor code modifications and runs the model under various policy scenarios that deviate from AEO assumptions, the name ''NEMS–BT'' refers to the model as used here. (BT stands for DOE's Building Technologies Program.)

TABLE IV–1—CLOTHES WASHER PRODUCT CLASSES—Continued

Product Classes in 430.32(g)	Product classes established in this rulemaking
iv. Front-loading	iv. Front-loading, standard (1.6 cubic feet or greater capacity).
v. Suds-saving.	

4. Non-Regulatory Programs

As part of the market and technology assessment, DOE reviews non-regulatory programs promoting energy efficient residential appliances in the United States. Non-regulatory programs that DOE considers in its market and technology assessment include ENERGY STAR, a voluntary labeling program administered jointly by the U.S. Environmental Protection Agency (EPA) and DOE. ENERGY STAR identifies energy efficient products through a qualification process.[18] To qualify, a product must exceed Federal minimum standards by a specified amount, or if no Federal standard exists, a product must exhibit select energy-saving features. ENERGY STAR specifications currently exist for residential clothes washers.

5. Technology Options

As part of the market and technology assessment, DOE developed a list of technologies to consider for improving the efficiency of residential clothes washers. Initially, these technologies encompassed all those DOE believes would improve energy efficiency and are technologically feasible. Chapter 3 of the direct final rule TSD includes the detailed list of all technology options identified for residential clothes washers.[19] DOE received multiple comments from interested parties in response to the technologies proposed for analysis.

In response to the framework document, interested parties suggested to DOE various databases from which it could obtain relevant product features and performance data. ALS recommended that DOE examine the CEC, FTC, and DOE certification databases, as well as the Web sites that ALS maintains for its own brands. (ALS, No. 13 at p. 2) The California Utilities and PG&E noted discrepancies among several databases, for instance that not all clothes washer models appear in all relevant lists, and requested that DOE reconcile the differences among them. (California Utilities, No. 19 at p. 4) DOE collected information to support this rulemaking from as many publicly available sources as it could identify, including trade publications, technical reports, manufacturers' literature, product databases, and inputs from interested parties. As part of its data collection, DOE reviewed all of those databases, as well as others that include qualifying product lists from ENERGY STAR and the CEE. In doing so, DOE evaluated product data critical to its analysis to ensure that appropriate values were being used.

ASAP, the Joint Comment, and PG&E stated that the data collection should include more recent data than for 2007. According to ASAP, more recent data would capture changes in market share as well as the effects of manufacturer production tax credits. (ASAP, Public Meeting Transcript, No. 7 at p. 122; Joint Comment, No. 15 at p. 8; PG&E, Public Meeting Transcript, No. 7 at p. 36) DOE attempts to collect the most comprehensive and recent data available. For today's direct final rule, DOE used AHAM's residential clothes washer data submission, which included shipments, shipment-weighted efficiency, and market share efficiency data through 2008.

The California Utilities recommended that DOE collect data on sales-weighted clothes washer capacity, preferably in increments of 0.5 cubic feet, because they suggest that capacity has a greater effect on clothes washer efficiency than do other features. The Joint Comment also recommended that shipment data be disaggregated by capacity in at most 0.5-cubic-foot increments, and that such data should identify fill control type (*i.e.,* adaptive water fill control, manual fill control, or combination adaptive and manual fill control). The Joint Comment stated that DOE also should collect shipment data for combination washer/dryers. (California Utilities, No. 19 at p. 4; Joint Comment, No. 15 at pp. 4, 8) DOE is unaware of residential clothes washer shipments data disaggregated to the granularity suggested by the California Utilities and the Joint Comment. DOE requested that interested parties provide such data or information on sources to obtain this information but received no further information.

B. Screening Analysis

DOE uses the following four screening criteria to determine which technology options are suitable for further consideration.

(1) *Technological feasibility.* DOE will consider technologies incorporated in commercial products or in working prototypes to be technologically feasible. (The technological feasibility of options was discussed in the preceding section as part of the market and technology assessment.)

(2) *Practicability to manufacture, install, and service.* If mass production and reliable installation and servicing of a technology in commercial products could be achieved on the scale necessary to serve the relevant market at the time the standard comes into effect, then DOE will consider that technology practicable to manufacture, install, and service.

(3) *Adverse impacts on product utility or product availability.* If DOE determines a technology would have significant adverse impact on the utility of the product to significant subgroups of consumers, or would result in the unavailability of any covered product type with performance characteristics (including reliability), features, sizes, capacities, and volumes that are substantially the same as products generally available in the United States at the time, it will not consider this technology further.

(4) *Adverse impacts on health or safety.* If DOE determines that a technology will have significant adverse impacts on health or safety, it will not consider this technology further.

10 CFR part 430, subpart C, appendix A, (4)(a)(4) and (5)(b).

Technologies that pass through the screening analysis are referred to as "design options" in the engineering analysis. Details of the screening analysis are provided in chapter 4 of the direct final rule TSD.

In the framework document, DOE identified the following initial technology options that could improve the efficiency of residential clothes washers, as shown in Table IV–2.

TABLE IV–2—INITIAL TECHNOLOGY OPTIONS FOR RESIDENTIAL CLOTHES WASHERS

1. Adaptive control systems.
2. Added insulation.
3. Advanced agitation concepts for vertical-axis machines.
4. Automatic fill control.
5. Bubble action.
6. Direct-drive motor.
7. Electrolytic disassociation of water.
8. Horizontal-axis design.
9. Horizontal-axis design with recirculation.
10. Hot water circulation loop.
11. Improved fill control.

[18] For more information, visit *www.energystar.gov.*

[19] DOE notes that it included two technology options, improved horizontal axis washer drum design and reduced thermal mass, in its initial list of options, but later determined in its engineering analysis that available data did not indicate that these technologies improved energy efficiency of clothes washers. See section IV.C.1,

TABLE IV–2—INITIAL TECHNOLOGY OPTIONS FOR RESIDENTIAL CLOTHES WASHERS—Continued

12. Improved horizontal-axis washer drum design.
13. Improved water extraction to lower remaining moisture content.
14. Increased motor efficiency.
15. Low-standby-power design.
16. Ozonated laundering.
17. Plastic particle cleaning.
18. Reduced thermal mass.
19. Silver ion injection.
20. Spray rinse or similar water-reducing rinse technology.
20. Steam washing.
21. Thermostatically controlled mixing valves.
22. Tighter tub tolerance.
23. Ultrasonic washing.

DOE received the following specific comments with regard to the screening analysis for the residential clothes washer technology options presented in the framework document.

1. Technologies Requiring Clarification or Reclassification

AHAM, BSH, and GE commented that the horizontal-axis, top-loading clothes washer described in the framework document should be considered as a horizontal-axis product regardless of loading position. (AHAM, Public Meeting Transcript, No. 7 at p. 53; AHAM, No. 16 at p. 3; BSH, No. 11 at p. 3; GE, No. 20 at p. 1) ALS commented that one very small U.S. manufacturer has made a horizontal-axis top-loader, but it has not been readily accepted by consumers. (ALS, No. 13 at p. 2) As discussed in section III.A.2, DOE maintains product class distinction by method of loading for today's final rule. Therefore, DOE considers a horizontal-axis design as a technology to improve the efficiency of top-loading clothes washers. DOE notes that such products are currently on the market in the United States.

Several manufacturers requested additional information on some of the technology options without further comment. AHAM, GE, and Whirlpool requested clarification on bubble action, electrolytic disassociation of water, and improved horizontal-axis washer drum design. AHAM and GE stated that they sought clarification on increased motor efficiency, BSH requested clarification on improved horizontal-axis washer drum design and tighter tub tolerance, and Whirlpool requested clarification on the reduced thermal mass technology option. ALS stated it would not offer comment on electrolytic disassociation of water, ozonated laundering, plastic particle cleaning, and ultrasonic washing until more information was available on the technology. (AHAM, Public Meeting Transcript, No. 7 at pp. 52–53; AHAM, No. 16 at p. 3; ALS, No. 13 at p. 4; BSH, No. 11 at p. 3; GE, No. 20 at p. 1; Whirlpool, No. 22 at p. 4) ASAP asked whether the low standby-power design included both standby and off modes. (ASAP, Public Meeting Transcript, No. 7 at p. 63) Additional detail on each of these technologies is provided in chapter 3 of the direct final rule TSD.

DOE requested comment in the framework document on whether additional technology options should be considered. ALS and Whirlpool stated that they are unaware of additional technologies that should be considered in DOE's preliminary analysis. (ALS, No. 13 at p. 5; Whirlpool, No. 22 at p. 5) AHAM and GE suggested that DOE add turbidity sensors to the list of technology options considered. Whirlpool commented that turbidity sensors have not been proven to provide adequate stain removal, soil removal, and rinsing performance. (AHAM, Public Meeting Transcript, No. 7 at p. 68; AHAM, No. 16 at p. 4; GE, No. 20 at p. 1; Whirlpool, No. 22 at p. 5) Multiple manufacturers stated to DOE during interviews that turbidity sensors have not been implemented in clothes washers largely due to technical barriers such as the high foaming properties of U.S. laundry detergents. Therefore, DOE did not add turbidity sensors as a technology option.

AHAM, GE, Samsung, and SCE stated that DOE should evaluate smart grid-enabled, demand-responsive clothes washers. AHAM and GE identified peak load shedding, wherein peak electricity demand is reduced via voluntary curtailment of clothes washer usage during certain times, as an important capability of such clothes washers. (AHAM, Public Meeting Transcript, No. 7 at p. 31; AHAM, No. 16 at p. 4; GE, Public Meeting Transcript, No. 7 at p. 31; GE, No. 20 at pp. 1, 3; Samsung, No. 25 at p. 4; SCE, Public Meeting Transcript, No. 7 at pp. 30, 64) DOE is unaware at this time of any such clothes washers available on the U.S. market for evaluation in terms of energy and water savings. Therefore, DOE did not consider smart-grid or other network-enabled technology options in this rulemaking.

In the framework document, DOE tentatively included steam washing in the list of residential clothes washer technology options. AHAM, GE, and Whirlpool noted that steam washing is already available in higher price point clothes washers. BSH stated that it has found through laboratory testing that steam washing does not improve cleaning performance. (AHAM, No. 16 at p, 4; BSH, No. 11 at p. 3; GE, No. 20 at p. 1; Whirlpool, No. 22 at p. 4) DOE research and testing indicates that steam generation requires significantly more energy than the potential energy savings associated with using less hot water during the wash cycle. Therefore, in the final list of technology options, DOE did not consider steam washing as a means to reducing energy consumption.

2. Technological Feasibility

AHAM, BSH, GE, and Whirlpool stated that added insulation would provide no meaningful energy savings, resulting in a minimal impact on MEF. BSH also stated that added insulation would be an issue for Underwriters Laboratories (UL) listing, and that the energy savings associated with horizontal-axis designs that incorporate recirculation may be small. (AHAM, Public Meeting Transcript, No. 7 at p. 52; AHAM, No. 16 at p. 3; BSH, No. 11 at p. 3; GE, No. 20 at p. 1; Whirlpool, No. 22 at p. 3) DOE agrees that the energy savings associated with added insulation would be negligible, particularly as the amount of hot water used in clothes washers decreases. DOE did not observe insulation around the tub in any of the units in its test sample, and multiple manufacturers stated that there was no energy benefit associated with the use of insulation. Therefore, DOE screened out added insulation. For horizontal-axis design with recirculation, DOE observes that units incorporating this design are available on the market, and one manufacturer stated that it can achieve energy savings of about 5 percent. Therefore, DOE retained horizontal-axis design with recirculation for its analysis.

AHAM, GE, and Whirlpool commented that standby power accounts for a small percentage of total energy consumption—AHAM estimates it accounts for 3 percent of annual energy use—so that designs incorporating low standby power would have a minimal impact. (AHAM, Public Meeting Transcript, No. 7 at p. 53; AHAM, No. 16 at p. 3; GE, No. 20 at p. 1; Whirlpool, No. 22 at p. 4) DOE recognizes that standby power is a relatively small percentage of annual clothes washer energy consumption. Under EPCA, as amended by EISA 2007, however, DOE is required to integrate standby and off mode energy use into the energy efficiency metric if technically feasible and consistent with 42 USC 6295(o). Today's final rule includes amendments to include measures for standby and off mode power consumption for clothes washers.

DOE received additional comments from interested parties suggesting that DOE exclude certain technologies proposed in the framework document from further analysis because they already are in widespread use. AHAM, BSH, GE, and Whirlpool commented that adaptive control systems, automatic fill control, improved fill control, spray rinse or similar water-reducing rinse technologies, and thermostatically controlled mixing valves are already widely used in residential clothes washers, although they assumed that improved fill control was the same technology as adaptive fill controls. AHAM, GE, and Whirlpool stated that direct-drive motors, horizontal-axis designs with recirculation, and hot water circulation loops also are widely used. AHAM and GE further stated that the widespread use of direct-drive motors currently applies only to top-loaders, although the technology is also available for front-loaders. Whirlpool added that horizontal-axis design is widely used. According to Whirlpool, the efficiency gains from these technology options are being recognized already. AHAM, BSH, and GE further commented that reduced thermal mass is already in widespread use for horizontal-axis clothes washers. AHAM, BSH, GE, and Whirlpool also stated that current products are nearing the maximum possible centrifugal force levels, so that no additional energy savings could be achieved by improved water extraction to lower remaining moisture content. (AHAM, Public Meeting Transcript, No. 7 at p. 53; AHAM, No. 16 at pp. 3–4; BSH, No. 11 at p. 3; GE, No. 20 at p. 1; Whirlpool, No. 22 at pp. 3–4) DOE evaluated each of these technologies as part of its reverse-engineering and manufacturer interviews, and determined that baseline clothes washers are available that meet current Federal standards without the use of such designs, each of which represents a potential means to improve energy efficiency. DOE does not consider level of commercialization in itself to be an indicator of whether a technology should be screened out. Therefore DOE retained all the above mentioned technology options for its analysis.

According to Whirlpool, it routinely pursues increased motor efficiency in its product development. (Whirlpool, No. 22 at p. 4) Because this technology option meets DOE's screening criteria, it was retained for further analysis.

3. Practicability to Manufacture, Install, and Service/Adverse Impacts on Product Utility or Availability

AHAM, BSH, GE, and Whirlpool commented that advanced agitation concepts already exist in high efficiency top-loading residential clothes washers. Whirlpool stated that the cost of this technology option limits its adoption to higher-priced models. (AHAM, No. 16 at p. 3; BSH, No. 11 at p. 3; GE, No. 20 at p. 1; Whirlpool, No. 22 at p. 3) DOE considers costs of the design options necessary to achieve each efficiency level as part of the LCC and PBP analysis. Therefore, DOE retained advanced agitation concepts for top-loading machines for its analysis.

For ozonated laundering, AHAM and GE commented that they are aware of such technology only for expensive stand-alone units. According to those commenters, it is unclear how ozonated laundering could be implemented into the more price-conscious residential market. (AHAM, Public Meeting Transcript, No. 7 at p. 53; AHAM, No. 16 at p. 3; GE, No. 20 at p. 1) Whirlpool stated that ozonated laundering offers poor cleaning performance and is quite costly. (Whirlpool, No. 22 at p. 4) ASAP, AWE, and the Joint Comment noted that residential clothes washers using ozonated laundry technology currently are on the market in Japan. AWE specifically mentioned the Sanyo Aqua Ozone combination washer/dryer and stated that ozone is also used by multiple manufacturers for commercial laundry. ASAP and the Joint Comment stated that ozonated laundry allows significant reductions in water and energy use. (ASAP, Public Meeting Transcript, No. 7 at p. 63; AWE, No. 12 at p. 2; Joint Comment, No. 15 at p. 4) Because no such residential clothes washers have been produced or demonstrated for the U.S. market, DOE does not believe this technology would be practicable to manufacture, install, and service on the scale necessary to serve the U.S. residential clothes washer market at the time of the effective date of an amended standard. Also, because implementation of this technology in a residential application is so limited, DOE is unable to adequately assess the impacts on consumer health or utility. For these reasons, DOE screened out ozonated laundry.

AHAM, BSH, GE, and Whirlpool stated that plastic particle cleaning does not provide effective wash performance. BSH added that other concerns include the manufacture, maintenance, and disposal of the plastic particles. (AHAM, Public Meeting Transcript, No. 7 at p. 54; AHAM, No. 16 at p. 4; BSH, No. 11 at p. 3; GE, No. 20 at p. 1; Whirlpool, No. 22 at p. 4) Samsung commented that plastic particle cleaning would have to be evaluated with consideration of wash and rinse performance. (Samsung, No. 25 at p. 3) Though clothes washers using plastic particle cleaning exist in working prototypes, this technology has not yet been commercialized, and thus consumer utility has yet to be thoroughly evaluated in terms of cleaning performance, as well as handling of the plastic particles. In addition, because no clothes washer manufacturer is currently producing such a machine, and because the reliability and consumer habits associated with using plastic particles are as yet unknown, DOE believes that it would not be practicable to manufacture, install, and service this technology on the scale necessary to serve the relevant market at the time of the effective date of an amended standard. For these reasons, DOE screened out plastic particle cleaning.

Whirlpool commented that tighter tub tolerance can be achieved, but the technology option is costly enough to limit its adoption to higher price-point clothes washers because a stronger structure is required. (Whirlpool, No. 22 at p. 4) Because DOE accounts for the cost associated with each design option necessary to achieve a certain efficiency level, it did not screen out tighter tub tolerance on this basis and retained this design option for consideration in the engineering analysis.

AHAM, BSH, GE, and Whirlpool stated that ultrasonic washing is not a proven technology for residential clothes washers. Whirlpool further stated that this technology has not been proven to provide adequate stain removal, soil removal, or rinsing performance. (AHAM, Public Meeting Transcript, No. 7 at p. 54; AHAM, No. 16 at p. 4; BSH, No. 11 at p. 3; GE, No. 20 at p. 1; Whirlpool, No. 22 at p. 4) DOE's research supports these comments, indicating that ultrasonic washing has not been shown to remove soil from clothes adequately. In addition, bubble cavitations caused by standing ultrasonic waves potentially could damage fragile clothing or clothing fasteners, further reducing product utility. For these reasons, DOE screened out ultrasonic washing.

DOE understands that bubble action has been incorporated into commercially available residential clothes washers in Europe and Asia. Because production is nonexistent in the U.S., however, DOE does not believe that this technology would be practicable to manufacture, install, and service on the scale necessary to serve the residential market at compliance date of new standards. For these reasons, DOE screened out bubble action.

4. Adverse Impacts on Health or Safety

ALS stated that it was not aware of any technologies that should be removed from consideration due to safety concerns. (ALS, No. 13 at p. 4)

ASAP and the Joint Comment stated that DOE should retain silver ion injection because it provides a deodorizing action in cold water washing and currently is available in the U.S. residential clothes washer market. According to the Joint Comment, such technology may encourage consumers to use fewer warm and hot water cycles. (ASAP, Public Meeting Transcript, No. 7 at p. 63; Joint Comment, No. 15 at p. 4) Whirlpool acknowledged that some manufacturers have incorporated silver ion technology as a means of disinfection, but stated that silver has an adverse impact on the environment. Whirlpool commented that the U.S. EPA requires that silver used for such a purpose be reported and tracked under the Federal Insecticide, Fungicide, and Rodenticide Act. (Whirlpool, No. 22 at p. 5) The EPA reporting requirement for clothes washers incorporating silver does not prevent commercialization of such technology, and DOE is not aware that any adverse impacts on health or safety have been demonstrated for this technology. Therefore DOE retained this option for consideration in the engineering analysis.

5. Additional Screening Criteria

DOE received a number of comments from interested parties recommending that it use additional criteria for screening technology options besides the four listed in 10 CFR part 430, subpart C, appendix A at 4(a)(4). AHAM, BSH, GE, and Whirlpool commented that technology options also should be evaluated on the basis of wash performance, rinse performance, and fabric care (damage, fraying, etc.). (AHAM, No. 16 at p. 4; BSH, No. 11 at p. 3; GE, No. 20 at p. 1; Whirlpool, No. 22 at p. 5) Miele, Inc. (Miele) questioned whether DOE would be evaluating each technology option on the basis of adequate wash performance. (Miele, Public Meeting Transcript, No. 7 at p. 65) For this rulemaking, DOE used the screening criteria set forth in its regulations. Technologies are evaluated in the screening analysis to determine whether they have an adverse impact on product utility or availability. Because DOE believes that the general utility of a clothes washer includes the ability to clean clothing adequately, DOE screened out those technologies that it believes have not been demonstrated to achieve adequate cleaning (*i.e.,* ultrasonic washing, as discussed previously).

Based on comments received regarding the initial technology options, DOE retained the design options shown in Table IV–3 for its subsequent engineering analysis. These remaining design options met all of the screening criteria listed above.

TABLE IV–3—DESIGN OPTIONS RETAINED FOR ENGINEERING ANALYSIS

1. Adaptive control systems.
2. Advanced agitation concepts for top-loading machines.
3. Automatic water fill control.
4. Direct-drive motor.
5. Horizontal-axis design.
6. Horizontal-axis design with recirculation.
7. Hot water circulation loop.
8. Improved fill control.
9. Improved horizontal-axis washer drum design.
10. Improved water extraction to lower remaining moisture content.
11. Increased motor efficiency.
12. Low-standby-power electronic controls.
13. Reduced thermal mass.
14. Silver ion injection.
15. Spray rinse or similar water-reducing rinse technology.
16. Thermostatically controlled mixing valves.
17. Tighter tub tolerance.

C. Engineering Analysis

In the engineering analysis, DOE evaluates a range of product efficiency levels and their associated manufacturing costs. The purpose of the analysis is to estimate the incremental manufacturer production costs (MPCs) associated with increasing efficiency levels above that of the baseline model in each product class. The engineering analysis considers technologies not eliminated in the screening analysis, although certain technologies are not analyzed if data does not exist to evaluate the energy efficiency characteristics of the technology; available data suggest that the efficiency benefits of the technology are negligible; or for reasons stated in the March 2012 TP final rule, DOE did not amend the test procedure to measure the energy impact of these technologies. DOE considers the remaining technologies, designated as design options, in developing cost-efficiency curves, which subsequently are used for the LCC and PBP analyses.

DOE has identified the following three methodologies for generating the manufacturing costs needed for the engineering analysis: (1) The design-option approach, which provides the incremental costs of adding to a baseline model design options that will improve its efficiency; (2) the efficiency-level approach, which provides the relative costs of achieving increases in energy efficiency levels, without regard to the particular design options used to achieve such increases; and (3) the cost-assessment (or reverse-engineering) approach, which provides ''bottom-up'' manufacturing cost assessments for achieving various levels of increased efficiency, based on detailed data regarding costs for parts and material, labor, shipping/packaging, and investment for models that operate at particular efficiency levels.

DOE conducted the engineering analyses for the top-loading standard and front-loading standard product classes using a combination of the cost-assessment approach and the efficiency-level approach. The cost-assessment approach provides an accurate means for estimating a single manufacturer's incremental manufacturing costs for achieving various levels of increased efficiency. This approach involved physically disassembling commercially available products to develop cost-efficiency relationships for each manufacturer's product lines. Because each manufacturer may choose a different path to achieve higher levels of efficiency, an efficiency-level approach produces an industry-wide cost-efficiency relationship for each product class. DOE developed cost-efficiency relationships for the top-loading standard and front-loading standard product classes by calculating the market-weighted average of the individual cost-efficiency relationships it developed for each manufacturer.

Because less data was available for the top-loading compact and front-loading compact product classes, DOE used the design-option approach to develop the cost-efficiency relationships for these product classes. For the top-loading compact product class, DOE developed the cost-efficiency relationship by estimating the incremental costs of adding specific design options to a baseline model that would provide sufficient improvement in efficiency to achieve the higher efficiency levels considered for the analysis. For the front-loading compact product class, DOE estimated the efficiency of a baseline product by extrapolating the rated efficiencies of front-loading clothes washers with capacities nearing those that delineate the compact product class (*i.e.,* 1.6 to 3.0 cubic feet). DOE then estimated the incremental cost of adding specific design options to this baseline model that would improve its efficiency enough to achieve the higher efficiency level considered for the analysis.

The efficiency levels that DOE considered in the engineering analysis are attainable using technologies currently available on the market for residential clothes washers. In addition, to provide interested parties with additional information about DOE's assumptions and results and the ability to perform independent analyses for verification, DOE associated each efficiency level with specific technologies that manufacturers might use. Chapter 5 of the direct final rule TSD describes the methodology and results of the efficiency level analysis used to derive the cost-efficiency relationships.

AHAM, ALS, GE, Samsung, and Whirlpool commented that they support the use of an efficiency-level approach for the analysis. (AHAM, Public Meeting Transcript, No. 7 at p. 81; AHAM, No. 16 at p. 5; ALS, No. 13 at p. 9; GE, No. 20 at p. 1; Samsung, No. 25 at p. 4; Whirlpool, No. 22 at p. 6) The Joint Comment stated that it supports a design-option approach, with the most significant design options evaluated separately rather than aggregated with other measures to help ensure transparency of the analysis. (Joint Comment, No. 15 at p. 5) The California Utilities stated that DOE should give greater weight to its reverse-engineering approach to isolate the cost premium of features on higher-efficiency clothes washers that may not contribute to or may even adversely affect efficiency. (California Utilities, No. 19 at p. 4) As discussed earlier, and as described in further detail in chapter 5 of the direct final rule TSD, DOE used a combination of these approaches, as appropriate, to develop the cost-efficiency relationships for each product class. The cost-efficiency relationships for each product class reflect only those design options that enable higher efficiencies, and exclude other non-efficiency related features that may contribute additional cost to higher-efficiency products. Details of the features and technologies associated with each efficiency level are also provided in chapter 5.

1. Other Technologies Not Analyzed

In performing the engineering analysis, DOE did not consider certain technologies that could not be evaluated for one or more of the following reasons: (1) Data are not available to evaluate the energy efficiency characteristics of the technology; (2) available data suggested that the efficiency benefits of the technology would be negligible; and (3) for the reasons stated in the March 2012 TP final rule, DOE did not amend the test procedure to measure the energy impact of these technologies. In its final analysis, DOE did not include the following design options:

a. Adaptive Control Systems

In the September 2010 TP NOPR, DOE stated that it was aware of multiple clothes washer models available on the market that use adaptive control technologies to respond to measured or inferred load size and fabric mix. However, as described in the August 2011 TP SNOPR, these models have since been discontinued, and DOE is unaware of any other residential clothes washers currently on the market offering adaptive controls other than adaptive fill control. Adaptive controls could allow a clothes washer to sense the fabric mix and soil level of a wash load, for example, and then adjust wash parameters such as the number of rinses, cycle time, and water temperatures accordingly. DOE is aware that many dishwashers incorporate adaptive controls by means of a turbidity sensor that adjusts the number and duration of wash and rinse cycles. The dishwasher test procedure accounts for this feature through the use of soiled dishware loads. 10 CFR part 430, subpart B, appendix C.

DOE is aware of other industry and international clothes washer test procedures that use a soiled wash load to determine wash performance, including AHAM HLW–1, ''Performance Evaluation Procedures for Household Clothes Washers''; IEC 60456, ''Clothes washing machines for household use–Methods for measuring the performance''; and Standards Australia/Standards New Zealand (AS/NZS) 2040.1, ''Performance of household electrical appliances–Clothes washing machines–Methods for measuring performance, energy and water consumption.'' [20] Because of the lack of commercially available clothes washers with adaptive features, however, DOE did not amend the test procedure in the March 2012 TP final rule to include provisions for measuring the energy consumption of clothes washers offering adaptive controls other than adaptive fill control. For these reasons, DOE did not include adaptive controls in its engineering analysis.

b. Improved Horizontal-Axis Washer Drum Design

Although several manufacturers have claimed improved wash performance and greater utility from improved drum designs for front-loading clothes washers, DOE is unaware of any publicly available data to corroborate a decrease in cycle time or water consumption or an increase in energy efficiency as a result of implementing this design option in residential clothes washers. Therefore, DOE did not include this design option in its analysis.

c. Reduced Thermal Mass

Reduced thermal mass describes minimizing the amount of energy consumed by heating the wash tub to the temperature of the wash water. DOE research suggests that manufacturers typically already use tubs with low thermal mass for all clothes washers and that there is no practicable way to manufacture clothes washers with significantly lower thermal mass beyond the current practice. DOE is unaware of any data available regarding efficiency improvements related to further decreasing the thermal mass of wash tubs, and therefore did not consider this technology in its analysis.

d. Silver Ion Injection

Silver ion injection provides an alternative to the traditional method of sanitizing clothes using a hot water wash. Silver ion injection works by electrolyzing pure silver during the wash and rinse cycles, and releasing the ions into the wash basket to sanitize the basket and wash load. While this technology option appears to offer an efficiency improvement by eliminating the need for high wash water temperatures, the current DOE test procedure does not capture this efficiency gain. Additionally, DOE lacks data on the reduction in warm and hot water cycles associated with silver ion injection and is not aware of any test procedures that could be used to measure any energy savings resulting from the use of silver ion injection. Because of this, DOE was unable to consider silver ion injection for further analysis.

e. Tighter Tub Tolerance

The tighter tub tolerance technology option reduces the annular volume between the inner wash basket and the outer tub and hence reduces the total amount of water required for a fill cycle. As a result of discussions with manufacturers, DOE believes that this technology option has reached its limit for efficiency gains. Decreasing the space between the wash basket and the tub any further could create problems such as ''suds lock,'' whereby suds remain between the wash basket and

[20] AHAM and AS/NZS standards are available online at *http://webstore.ansi.org/*.

tub; improper draining during the spin cycle; noise; and vibration, thereby negatively impacting product utility. Therefore, DOE did not consider this design option in its engineering analysis.

Table IV–4 shows the final list of design options that DOE retained for the engineering analysis.

TABLE IV–4—RETAINED DESIGN OPTIONS FOR RESIDENTIAL CLOTHES WASHERS

1. Advanced agitation concepts for top-loading machines.
2. Automatic water fill control.
3. Direct-drive motor.
4. Horizontal-axis design.
5. Horizontal-axis design with recirculation.
6. Hot water circulation loop.
7. Improved fill control.
8. Improved water extraction to lower remaining moisture content.
9. Increased motor efficiency.
10. Low-standby-power electronic controls.
11. Spray rinse or similar water-reducing rinse technology.
12. Thermostatically controlled mixing valves.

2. Baseline Efficiency Levels

In the framework document, DOE proposed baseline efficiency levels in active mode for top-loading standard, top-loading compact, and front-loading clothes washers. DOE did not consider front-loading compact models in the framework document. The Joint Petition, however, proposed standard levels for a front-loading compact product classes. In today's final rule, DOE defined baseline efficiency levels and higher efficiency levels for each of the four product classes to conduct its engineering analyses. DOE defined a baseline efficiency level of 1.60 MEF/8.5 WF for the front-loading compact product class, as well as an updated baseline efficiency level of 0.77 MEF/14.0 WF for the top-loading compact product class. Chapter 5 of the direct final rule TSD provides further details on the development of these baseline efficiency levels.

In the framework document, DOE based the baseline level for top-loading standard units on the MEF specified by current Federal energy conservation standards and the water factor (WF) requirement established by EISA 2007, which became effective for residential clothes washers manufactured on or after January 1, 2011. The top-loading compact MEF similarly was based on existing standards, with the WF scaled from the top-loading standard-size value by the ratio of MEFs for the two product classes. Because DOE understands that all commercially available front-loading clothes washers have efficiencies that meet or exceed the existing Federal standards and the former ENERGY STAR level of 1.72 MEF and 8.0 WF, effective prior to July 2009, DOE applied the former ENERGY STAR level to characterize the baseline unit efficiency for front-loading clothes washers.

AHAM, ALS, and BSH stated that they support the proposed baseline efficiency levels for top-loading standard (1.26 MEF/9.5 WF), top-loading compact (0.65 MEF/18.4 WF), and front-loading standard (1.72 MEF/8.0 WF) product classes. (AHAM, Public Meeting Transcript, No. 7 at p. 72; AHAM, No. 24 at p. 2; ALS, Public Meeting Transcript, No. 7 at p. 73; ALS, No. 13 at p. 5; BSH, No. 11 at p. 4) Whirlpool commented that it supports the proposed baseline efficiency levels for the top-loading standard and front-loading standard product classes. (Whirlpool, No. 22 at p. 5) The Joint Comment stated that DOE should determine the WF of baseline top-loading compact clothes washers through sampling rather than by scaling the standard-size baseline value. (Joint Comment, No. 15 at p. 5) For the direct final rule analysis, DOE defined the baseline efficiency levels for the standard product classes, both top-and front-loading, as they were defined in the framework document. DOE defined the baseline efficiency level of 0.77 MEF/14.0 WF for the top-loading compact product class based on a survey of products currently available on the market. This baseline represents an improvement over the 0.65 MEF/18.4 WF baseline defined in the framework document.

Samsung stated that because it does not support separate classes based on washer axis, it recommends a single baseline efficiency level. (Samsung, No. 25 at p. 4) For the reasons discussed in III.A.2 DOE has retained separate product classes based on method of access and capacity, and thus continued to use separate baseline efficiency levels for each product class.

BSH suggested including a front-loading compact product class, with a baseline efficiency level of 1.63 MEF/8.5 WF, based on data from the CEC residential clothes washer product database. (BSH, No. 11 at p. 4) The Joint Petition also included a front-loading compact product class. DOE defined a baseline efficiency level of 1.60 MEF/8.5 WF for the front-loading compact product class, based on an extrapolation of the rated efficiencies of front-loading clothes washers with capacities nearing those that delineate the compact product class (*i.e.,* 1.6 to 3.0 cubic feet). Chapter 5 of the direct final rule TSD provides further details of on the development of the baseline efficiency level for the front-loading compact product class.

AHAM, ALS, GE, and Samsung stated that no baseline efficiency levels need to be defined for top-loading semi-automatic and suds-saving product classes, since these product classes should be eliminated. (AHAM, No. 16 at p. 4; ALS, No. 13 at p. 5; GE, No. 20 at p. 1; Samsung, No. 25 at p. 4) Because DOE eliminated the top-loading semi-automatic and suds-saving product classes, DOE did not define corresponding baseline efficiency levels.

3. Higher Efficiency Levels

a. Efficiency Levels Proposed in Framework Document

In the framework document, DOE considered efficiency levels higher than baseline levels based on specifications prescribed by ENERGY STAR and CEE's Super-Efficient Home-Appliances Initiative. The highest efficiency levels were defined by the maximum available technology that DOE could identify on the market. Where the increments between adjacent efficiency levels were large, DOE proposed to add an intermediate ''gap-fill'' level. Table IV–5 through Table IV–7 show the efficiency levels proposed in the framework document, based on MEF and WF.

TABLE IV–5—EFFICIENCY LEVELS PROPOSED IN THE FRAMEWORK DOCUMENT FOR TOP-LOADING STANDARD RESIDENTIAL CLOTHES WASHER FRAMEWORK DOCUMENT

Level	Efficiency level description	Efficiency level	
		MEF (ft^3/kWh/cycle)	WF (gal/cycle/ft^3)
Baseline	DOE Standard	1.26	9.50

TABLE IV–5—EFFICIENCY LEVELS PROPOSED IN THE FRAMEWORK DOCUMENT FOR TOP-LOADING STANDARD RESIDENTIAL CLOTHES WASHER FRAMEWORK DOCUMENT—Continued

Level	Efficiency level description	Efficiency level	
		MEF (ft³/kWh/cycle)	WF (gal/cycle/ft³)
1	Gap Fill	1.40	9.50
2	Former ENERGY STAR (pre-July 2009)	1.72	8.00
3	Former ENERGY STAR (pre-Jan 2011), also CEE Tier 1	1.80	7.50
4	Current ENERGY STAR (Jan 2011), also CEE Tier 2	2.00	6.00
5	Max Available	2.26	4.48

TABLE IV–6—EFFICIENCY LEVELS PROPOSED IN THE FRAMEWORK DOCUMENT FOR TOP-LOADING COMPACT RESIDENTIAL CLOTHES WASHER FRAMEWORK DOCUMENT

Level	Efficiency level description	Efficiency level	
		MEF (ft³/kWh/cycle)	WF (gal/cycle/ft³)
Baseline	DOE Standard	0.65	18.40
1	Max Available	0.78	13.90

TABLE IV–7—EFFICIENCY LEVELS PROPOSED IN THE FRAMEWORK DOCUMENT FOR FRONT-LOADING RESIDENTIAL CLOTHES WASHER FRAMEWORK DOCUMENT

Level	Efficiency level description	Efficiency level	
		MEF (ft³/kWh/cycle)	WF (gal/cycle/ft³)
Baseline	Former ENERGY STAR (pre-July 2009)	1.72	8.00
1	Former ENERGY STAR (pre-Jan 2011), also CEE Tier 1	1.80	7.50
2	Current ENERGY STAR (Jan 2011), also CEE Tier 2)	2.00	6.00
3	CEE Tier 3	2.20	4.50
4	Gap Fill	2.40	4.20
5	Max Available	2.89	3.36

DOE received a number of comments on the efficiency levels and provides responses to those comments and changes made to the efficiency levels for today's direct final rule in the paragraphs that follow. The efficiency levels analyzed for today's final rule are set forth in section IV.C.3.b (Table IV–8 through Table IV–11).

Whirlpool stated that it supports the efficiency levels proposed in the framework document. (Whirlpool, No. 22 at p. 6) PG&E asked how DOE will prioritize MEF and WF when determining efficiency levels. As noted previously, efficiency levels were based primarily on levels defined by the ENERGY STAR and CEE voluntary programs. DOE subsequently added gap-fill levels based on data for available products, selecting combinations of MEF and WF that were achieved by a significant number of existing clothes washers and that also reasonably spanned the incremental changes in both metrics between the next-lowest and next-highest efficiency levels.

BSH proposed one additional efficiency level for a newly created front-loading compact product class above the baseline efficiency level it proposed—2.31 MEF/4.4 WF. BSH identified this as the maximum available technology level. (BSH, No. 11 at p. 6) The Consensus Agreement submitted by the Joint Petitioners includes efficiency standards for front-loading compact clothes washers of 1.72 MEF and 8.0 WF. As described previously, DOE defined a baseline efficiency level of 1.60 MEF and 8.5 WF for the front-loading compact product class. DOE defined one additional efficiency level at 1.72 MEF and 8.0 WF based on the standard level proposed in the Consensus Agreement.

ASAP, Earthjustice, and the Joint Comment stated that DOE should modify its proposed efficiency levels to harmonize them for standard-capacity top-loaders and front-loaders. In particular, those interested parties stated that DOE should set the highest efficiency level for the top-loading standard product class to CEE's Tier 3 level. (ASAP, Public Meeting Transcript, No. 7 at p. 87–88; Earthjustice, No. 17 at p. 7; Joint Comment, No. 15 at p. 5) The CEE Tier 3 level is 2.20 MEF/4.5 WF, which is slightly less stringent in MEF but slightly more stringent in WF than the maximum technologically feasible level for this product class identified in the framework document, 2.26 MEF/4.48 WF. Under EPCA, DOE is required to analyze the max-tech level for each product class. (42 U.S.C. 6295(o)(2)) In the framework document, DOE based its max-tech level for top-loading standard residential clothes washers on the maximum performance of products available on the market in the United States at that time. Since publication of the framework document, DOE became aware of a new max-tech unit on the market rated at 2.47 MEF and 3.6 WF. Therefore, in the direct final rule analysis, DOE created a new max-tech efficiency level corresponding to these efficiency ratings.

AHAM and ASAP questioned the gap-fill level identified as Efficiency Level 4 for front-loading clothes washers. ASAP recommended that Efficiency Level 4 be specified as having a WF of 4.0 rather than the value of 4.2 proposed in the framework document. (AHAM, Public Meeting Transcript, No. 7 at p. 89; ASAP, Public Meeting Transcript, No. 7 at p. 89) DOE proposed Efficiency Level 4 for front-loading clothes washers—2.40 MEF/4.20 WF—based on performance metrics represented in a number of models in the CEC and ENERGY STAR databases. Therefore, DOE retained Efficiency Level 4 at a WF of 4.2.

In addition, DOE's reverse engineering suggested that an additional gap-fill level between Efficiency Level 4 (gap-fill) and Efficiency Level 5 (max available) was warranted (see chapter 5 of the direct final rule TSD for more information). Based on a review of available products, DOE defined a second gap-fill level at 2.60 MEF/3.8 WF. DOE notes a small incremental span in WF between ASAP's proposed Efficiency Level 4 (4.0 WF) and DOE's additional gap-fill level (3.8 WF). DOE found no meaningful differences in technology options required to achieve either water consumption level. Therefore, DOE retained a WF of 3.8 for the additional gap-fill level.

b. Efficiency Levels Used in Final Analysis

Table IV–8 through Table IV–11 show the efficiency levels used in the final analysis according to the test procedure in appendix J1 as well as the revised test procedure in appendix J2.

TABLE IV–8—EFFICIENCY LEVELS FOR TOP-LOADING STANDARD RESIDENTIAL CLOTHES WASHER FINAL ANALYSIS

Level	Efficiency level description	Efficiency level—appendix J1		Integrated efficiency level—appendix J2	
		MEF (ft³/kWh/cycle)	WF (gal/cycle/ft³)	IMEF (ft³/kWh/cycle)	IWF (gal/cycle/ft³)
Baseline	DOE Standard + 0 W Standby	1.26	9.5	0.84	9.9
1	Gap Fill + 0 W Standby	1.40	9.5	0.98	9.9
2	Former ENERGY STAR (pre-2009) + 0 W Standby [Consensus Agreement 2015].	1.72	8.0	1.29	8.4
3 *	Former ENERGY STAR (pre-2011) + 2.3 W Standby.	1.80	7.5	1.34	7.9
5	Former ENERGY STAR (pre-2011) + 0.08 W Standby.	1.80	7.5	1.37	7.9
6	Current ENERGY STAR (Jan 2011) + 0.08 W Standby [Consensus Agreement 2018].	2.00	6.0	1.57	6.5
7	Max Available (at time of Framework Document) + 0.08 W Standby.	2.26	4.5	1.83	5.0
8	Current Max Available + 0.08 W Standby	2.47	3.6	2.04	4.1

* DOE also analyzed design options that would meet an efficiency level 4, represented by "Former ENERGY STAR (pre-2011) + 1.7 W Standby"; however, this efficiency level has the same IMEF and IWF as the efficiency level represented by Former ENERGY STAR (pre-2011) + 2.3 W Standby and is therefore not included in the table.

TABLE IV–9—EFFICIENCY LEVELS FOR FRONT-LOADING STANDARD RESIDENTIAL CLOTHES WASHER FINAL ANALYSIS

Level	Efficiency level description	Efficiency level—appendix J1		Integrated efficiency level—appendix J2	
		MEF (ft³/kWh/cycle)	WF (gal/cycle/ft³)	IMEF (ft³/kWh/cycle)	IWF (gal/cycle/ft³)
Baseline	Former ENERGY STAR (pre-2009) + 2.3 W Standby.	1.72	8.0	1.37	8.3
1	Former ENERGY STAR (pre-2009) + 1.7 W Standby.	1.72	8.0	1.39	8.3
2	Former ENERGY STAR (pre-2009) + 0.08 W Standby.	1.72	8.0	1.41	8.3
3	Former ENERGY STAR (pre-2011) + 0.08 W Standby.	1.80	7.5	1.49	7.8
4	Current ENERGY STAR (Jan 2011) + 0.08 W Standby.	2.00	6.0	1.66	6.3
5	CEE Tier 3 + 0.08 W Standby [Consensus Agreement 2015].	2.20	4.5	1.84	4.7
6	Gap Fill + 0.08 W Standby	2.40	4.2	2.02	4.4
7	Gap Fill + 0.08 W Standby	2.60	3.8	2.20	4.0
8	Max Available + 0.08 W Standby	2.89	3.2	2.46	3.4

TABLE IV–10—EFFICIENCY LEVELS FOR TOP-LOADING COMPACT RESIDENTIAL CLOTHES WASHER FINAL ANALYSIS

Level	Efficiency level description	Efficiency level—appendix J1		Integrated efficiency level—appendix J2	
		MEF (ft^3/kWh/cycle)	WF (gal/cycle/ft^3)	IMEF (ft^3/kWh/cycle)	IWF (gal/cycle/ft^3)
Baseline	Baseline product on the market	0.77	14.0	0.59	14.4
1	Consensus Agreement (2015 Proposed Standard).	1.26	14.0	0.86	14.4
2	Consensus Agreement (2018 Proposed Standard).	1.81	11.6	1.15	12.0

TABLE IV–11—EFFICIENCY LEVELS FOR FRONT-LOADING COMPACT RESIDENTIAL CLOTHES WASHER FINAL ANALYSIS

Level	Efficiency level description	Efficiency level—appendix J1		Integrated efficiency Level—appendix J2	
		MEF (ft^3/kWh/cycle)	WF (gal/cycle/ft^3)	IMEF (ft^3/kWh/cycle)	IWF (gal/cycle/ft^3)
Baseline	DOE-estimated baseline level	1.60	8.5	1.03	8.8
1	Consensus Agreement (2015 Proposed Standard).	1.72	8.0	1.13	8.3

As discussed in III.B, DOE recently published a revised test procedure, designated appendix J2, use of which will be required as of the compliance date of the 2015 standard in this direct final rule, absent adverse comment that results in withdrawal of today's direct final rule pursuant to 42 U.S.C. 6295(p)(4). 77 FR 13888. The revised test procedure establishes an IMEF metric that incorporates energy use in standby and off mode, and an IWF metric that incorporates water usage from all cycles included in the energy test cycle.

DOE included the impacts of new provisions in the amended test procedure in developing the IMEF/IWF efficiency levels in today's DFR. To perform this translation, DOE tested a wide range of both top-loading and front-loading clothes washers according to the test procedure at appendix J1 and the revised test procedure at appendix J2. Based on these tests, DOE developed correlation curves relating MEF to IMEF and WF to IWF. Chapter 5 of the direct final rule TSD provides additional detail on the method DOE used to convert from MEF/WF levels to IMEF/IWF levels.

Because the revised standards for residential clothes washers are required by EPCA to incorporate standby mode and off mode energy use (42 U.S.C. 6295(gg)(3)), DOE created efficiency levels for the top-loading standard and front-loading standard product classes that incorporate reduced standby power options into the MEF efficiency levels where DOE determined them to be most cost effective. In residential clothes washers, only units with electronic controls consume standby power; units with electromechanical controls consume no standby or off-mode power.

For the top-loading standard product class, standby power is likely to be added at Efficiency Level 3 in Table IV–8. This corresponds to the efficiency level at which electronic controls would be required. Because reduced standby power design options are more cost-effective than most other available design options, they are likely to be one of the first design options used by manufacturers to achieve higher IMEF ratings in units above Efficiency Level 3. DOE identified three distinct standby power design options, which are incorporated at Efficiency Level 3, Efficiency Level 4, and Efficiency Level 5. Efficiency Levels 6–8 incorporate the standby design option in Efficiency Level 5, which has the lowest energy use.

For the front-loading standard product class, DOE is unaware of any units that do not use electronic controls. Therefore, standby power is experienced at all efficiency levels. As with top-loading clothes washers, reduced standby power design options are more cost-effective than most other available design options, and they are likely to be one of the first design options used by manufacturers to achieve higher IMEF ratings in units above the baseline level. Therefore, as shown in Table IV–9, DOE incorporated the three distinct standby power design options at the Baseline Level, Efficiency Level 1, and Efficiency Level 2. Efficiency Levels 3–8 incorporate the standby design option in Efficiency Level 2, which has the lowest energy use.

Chapter 5 of the direct final rule TSD provides detailed descriptions of the design options associated with each efficiency level, including details of the active mode and standby mode efficiency levels for each product class.

For the front-loading standard product class, DOE introduced a second gap fill level in the final analysis at 2.6 MEF/3.8 WF (EL 7). During the reverse-engineering analysis, DOE observed specific technology options employed at this efficiency level, and thus determined that an additional gap fill at this level is appropriate.

For the top-loading compact product class, DOE defined the baseline efficiency level based on a survey of units currently available on the market, as described previously in section IV.C.2. Efficiency Level 1 and Efficiency Level 2 represent the standard levels proposed in the Consensus Agreement for 2015 and 2018, respectively. Chapter 5 of the direct final rule TSD provides detailed descriptions of the design options manufacturers are likely to use to achieve the higher efficiency levels.

For the front-loading compact product class, DOE defined the baseline efficiency level based on an extrapolation of the rated efficiencies of front-loading clothes washers with capacities nearing those that delineate the compact product class (*i.e.,* 1.6 to 3.0 cubic feet), as described in section IV.C.2. Efficiency Level 1 represents the 2015 standard level proposed in the Consensus Agreement.

Chapter 5 of the direct final rule TSD provides further details of the analysis performed on the efficiency levels for this product class. As discussed in more detail in chapter 5, manufacturers indicated during manufacturer interviews that the efficiency levels chosen by DOE would not result in an increased cycle time for units within any of the product classes established in today's direct final rule, an assertion that is supported by DOE analysis of test data and published product literature. DOE seeks comment on this issue in section II.B.3.

4. Maximum Technologically Feasible Efficiency Levels

In the framework document, DOE based its max-tech level for top-loading standard and front-loading standard residential clothes washers on the maximum performance of products currently on the market in the United States, based on its review of various product databases. DOE considered several models in each product class to determine max-tech values that best represent optimal performance of IMEF and IWF for clothes washers on the market. DOE sought comment on whether the ''maximum available'' efficiency levels, shown in Table IV–12, represented max-tech efficiency.

TABLE IV–12—PROPOSED MAXIMUM TECHNOLOGICALLY FEASIBLE EFFICIENCY LEVELS PROPOSED IN THE FRAMEWORK DOCUMENT FOR RESIDENTIAL CLOTHES WASHERS

Product class	Max-tech levels	
	MEF	WF
1. Top-loading, Compact (less than 1.6 ft^3 capacity)	0.78	13.90
2. Top-loading, Standard	2.26	4.48
3. Front-loading	2.89	3.36

The American Water Works Association (AWWA), the California Utilities, the Joint Comment, and PG&E objected to the use of ''maximum available'' efficiency levels as a substitute for max-tech. AWWA, the California Utilities, and the Joint Comment stated that DOE must survey available technologies to determine the maximum achievable levels. (AWWA, No. 14 at p. 1; California Utilities, No. 19 at p. 5; Joint Comment, No. 15 at p. 5; PG&E, Public Meeting Transcript, No. 7 at p. 90) Whirlpool stated that it believes that it manufactures the model that is the basis for the maximum available level for top-loading clothes washers. Whirlpool stated that this maximum available level is at or near the max-tech limit. Even so, Whirlpool stated that the platform is relatively costly (with a suggested retail price of $1099–$1299), so that it would not be an economically justified standard level. ALS commented that the max-tech efficiency level should not represent a niche product, a product with low-end capacity, or some proprietary design. SCE asked whether an efficiency-level approach would limit how DOE develops its max-tech levels. (ALS, No. 13 at p. 9; Whirlpool, Public Meeting Transcript, No. 7 at p. 91, Whirlpool, No. 22 at p. 6; SCE, Public Meeting Transcript, No. 7 at p. 90)

Under EPCA, DOE is required to consider the maximum technologically feasible level. DOE determines max-tech levels based on technologies that are either commercially available or have been demonstrated as working prototypes. If the max-tech design meets DOE's screening criteria, DOE considers the design in further analysis. DOE also considers consumer utility and availability of features, which may be met by a niche product, as required by EPCA.

As described previously, DOE became aware of a new top-loading standard clothes washer with a higher MEF and lower WF than the max-tech level considered in the framework document. This new max-tech efficiency level was added for the direct final rule analysis. For front-loading standard clothes washers, DOE did not identify any other designs or combinations of technologies beyond the ''maximum available'' that would lead to a different max-tech level without requiring proprietary designs. For top-loading compact clothes washers, DOE used the 2018 standard level proposed in the Consensus Agreement as the max-tech level, as described previously. For front-loading compact clothes washers, DOE used the 2015 standard level proposed in the Consensus Agreement as the max-tech level.

Finally, DOE has observed that the max-tech units on the market use a combination of significantly reduced water volumes, reduced water temperatures, extended cycle times, and extremely high spin speeds. (See chapter 5 of the direct final rule TSD). DOE is not aware of any additional design options that could be used to increase the efficiency beyond the max-tech levels without causing potential negative effects on consumer utility. Nor is DOE aware of any working prototype clothes washers that exceed the efficiency levels of the max-tech units on the market in the United States. Therefore, DOE believes the ''max available'' efficiency levels for residential clothes washers correspond to the maximum technologically feasible efficiency levels. Accordingly, DOE does not believe that using an efficiency-level approach would limit how it develops its max-tech levels.

Table IV–13 shows the max-tech levels used for the final analysis.

TABLE IV–13—MAXIMUM TECHNOLOGICALLY FEASIBLE EFFICIENCY LEVELS FOR RESIDENTIAL CLOTHES WASHERS FINAL ANALYSIS

Product class	Max tech levels—appendix J2	
	IMEF	IWF
Top-loading, Standard	2.04	4.1
Front-loading, Standard	2.46	3.4
Top-loading, Compact	1.15	12.0
Front-loading, Compact	1.13	8.3

5. Proprietary Designs

In its engineering and economic analyses DOE considers all design options that are commercially available or present in a working prototype, including proprietary designs and technologies. DOE will consider a proprietary design in the subsequent analyses only if the achieved efficiency level can also be reached using other nonproprietary design options. If the proprietary design is the only approach available to achieve a given efficiency level, then DOE will reject that efficiency level to avoid impacts on competition that would likely result.

AHAM, GE, and Whirlpool stated that they are not aware of any proprietary designs or technologies that would impact this rulemaking. (AHAM, Public Meeting Transcript, No. 7 at p. 93; AHAM, No. 16 at p. 5; GE, No. 20 at p. 1; Whirlpool, No. 22 at p. 7) Earthjustice commented that DOE must evaluate the maximum technologically feasible standards for clothes washers, including those that use proprietary technology. According to Earthjustice, DOE's unqualified rejection of efficiency levels incorporating proprietary technologies repeats the errors that DOE made over 25 years ago in refusing to analyze efficiency levels incorporating technologies available only in prototypes. In that rulemaking, Earthjustice stated that the D.C. Circuit wrote that DOE ''conclusively assume[d] that manufacturers cannot incorporate any prototypes for any product type or class into all appliances of that type or class [by the effective date of the standard].'' *Natural Resources Defense Council* v. *Herrington,* 768 F.2d 1355, 1396 (D.C. Cir. 1985). Earthjustice believes that DOE's approach in the current clothes washer rulemaking would similarly exclude a technology without any analysis of technological feasibility or economic justification. Earthjustice also stated that Congress clearly intended for DOE to carefully consider the impact of adopting standards that depend on the use of proprietary technologies, as it required in 42 U.S.C. 6295(o)(2)(B)(i)(V) that DOE consider the impact on competition in weighing the economic justification for a given standard level. Earthjustice concluded that DOE cannot lawfully exclude proprietary technologies from its analysis without a justification that complies with EPCA. (Earthjustice, No. 17 at pp. 9–10)

DOE considers in its analysis technologies that have been incorporated into working prototypes, consistent with the D.C. Circuit decision discussed above. DOE also considers proprietary technologies if the efficiency levels that can be met using those technologies can also be met using other, non-proprietary technologies. DOE does not consider proprietary technologies when such technologies provide the only means to reach a given efficiency level because of the potential market barriers and impacts on competition.

6. Reverse Engineering

ASAP and Samsung stated that they support DOE's reverse engineering. (ASAP, Public Meeting Transcript, No. 7 at p. 74; Samsung, No. 25 at p. 4) The California Utilities requested that DOE explore how to make pertinent manufacturer cost data available to the public while protecting manufacturer confidentiality. (California Utilities, No. 19 at p. 5) To supplement and validate the AHAM data submittals, DOE conducted interviews with manufacturers. Cost information supplied to DOE by the manufacturers was aggregated or otherwise incorporated into the analysis to protect confidentiality. Data developed by DOE during the teardowns and subsequent analysis are detailed in chapter 5 of the direct final rule TSD.

AHAM, ALS, BSH, and Whirlpool suggested that DOE complete its reverse-engineering analysis on the following four product types:

• Conventional agitator top-loading;
• High efficiency agitator top-loading;
• High efficiency non-agitator top-loading; and
• Standard-size front-loading.

AHAM, GE, and Whirlpool also recommended that DOE reverse-engineer compact top-loading clothes washers. BSH recommended adding both compact top-loading and compact front-loading clothes washers. (AHAM, Public Meeting Transcript, No. 7 at p. 81; AHAM, No. 16 at p. 5; ALS, No. 13 at p. 9; BSH, No. 11 at p. 4; GE, No. 20 at p. 1; Whirlpool, No. 22 at p. 6) DOE's test sample for its reverse engineering analysis included representative residential clothes washers from all of these categories. DOE modeled the likely construction of a compact front-loading clothes washer by extrapolating from front-loading clothes washers with capacities nearing those delineating the compact product class (*i.e.,* between 1.6 and 3.0 cubic feet in capacity).

ASAP stated that, when DOE evaluates the characteristics of baseline models, no extraneous features and amenities should be included that do not contribute to energy and water performance. (ASAP, Public Meeting Transcript, No. 7 at p. 74) DOE's cost models disaggregate total manufacturing costs by sub-assemblies and individual components, thereby allowing DOE to identify only those specific design options contributing to incremental efficiency improvements.

Based on product teardowns and cost modeling, DOE developed overall cost-efficiency relationships for all four residential clothes washer product classes. Table IV–14 through Table IV–17 show DOE's estimates of incremental manufacturing cost for improvement of clothes washer efficiency above the baseline. As mentioned previously in section IV.C.3.b, DOE applied the correlation curves it developed to translate MEF into IMEF and WF into IWF. Chapter 5 of the direct final rule TSD provides details on DOE's engineering analysis, including the development of the cost-efficiency curves and correlation curves.

TABLE IV–14—COST-EFFICIENCY RELATIONSHIP FOR TOP-LOADING STANDARD RESIDENTIAL CLOTHES WASHERS

Efficiency level	Efficiency level—appendix J1		Integrated efficiency level—appendix J2		Incremental manufacturing cost (2010$)
	MEF (ft^3/kWh/cycle)	WF (gal/cycle/ft^3)	IMEF (ft^3/kWh/cycle)	IWF (gal/cycle/ft^3)	
Baseline	1.26	9.5	0.84	9.9	$0.00
EL 1	1.40	9.5	0.98	9.9	3.11
EL 2	1.72	8.0	1.29	8.4	8.44
EL 3 *	1.80	7.5	1.34	7.9	13.06
EL 5	1.80	7.5	1.37	7.9	14.24
EL 6	2.00	6.0	1.57	6.5	25.29
EL 7	2.26	4.5	1.83	5.0	60.65
EL 8	2.47	3.6	2.04	4.1	69.79

* EL4 is not included in the table because it has the same IMEF and IWF as EL 3. The incremental manufacturing cost for EL 4 is $16.98.

TABLE IV–15—COST-EFFICIENCY RELATIONSHIP FOR FRONT-LOADING STANDARD RESIDENTIAL CLOTHES WASHERS

Efficiency level	Efficiency level—appendix J1		Integrated efficiency level—appendix J2		Incremental manufacturing cost (2010$)
	MEF (ft^3/kWh/cycle)	WF (gal/cycle/ft^3)	IMEF (ft^3/kWh/cycle)	IWF (gal/cycle/ft^3)	
Baseline	1.72	8.0	1.37	8.3	$0.00
EL 1	1.72	8.0	1.39	8.3	3.92
EL 2	1.72	8.0	1.41	8.3	1.18
EL 3	1.80	7.5	1.49	7.8	3.18
EL 4	2.00	6.0	1.66	6.3	6.20
EL 5	2.20	4.5	1.84	4.7	17.25

TABLE IV–15—COST-EFFICIENCY RELATIONSHIP FOR FRONT-LOADING STANDARD RESIDENTIAL CLOTHES WASHERS—Continued

Efficiency level	Efficiency level—appendix J1		Integrated efficiency level—appendix J2		Incremental manufacturing cost (2010$)
	MEF (ft³/kWh/cycle)	WF (gal/cycle/ft³)	IMEF (ft³/kWh/cycle)	IWF (gal/cycle/ft³)	
EL 6	2.40	4.2	2.02	4.4	40.36
EL 7	2.60	3.8	2.20	4.0	53.88
EL 8	2.89	3.2	2.46	3.4	73.51

TABLE IV–16—COST-EFFICIENCY RELATIONSHIP FOR TOP-LOADING COMPACT RESIDENTIAL CLOTHES WASHERS

Efficiency level	Efficiency level—appendix J1		Integrated efficiency level—appendix J2		Incremental manufacturing cost (2010$)
	MEF (ft³/kWh/cycle)	WF (gal/cycle/ft³)	IMEF (ft³/kWh/cycle)	IWF (gal/cycle/ft³)	
Baseline	0.77	14.0	0.59	14.4	$0.00
EL 1	1.26	14.0	0.86	14.4	5.00
EL 2	1.81	11.6	1.15	12.0	45.00

TABLE IV–17—COST-EFFICIENCY RELATIONSHIP FOR FRONT-LOADING COMPACT RESIDENTIAL CLOTHES WASHERS

Efficiency level	Efficiency level—appendix J1		Integrated efficiency level—appendix J2		Incremental manufacturing cost (2010$)
	MEF (ft³/kWh/cycle)	WF (gal/cycle/ft³)	IMEF (ft³/kWh/cycle)	IWF (gal/cycle/ft³)	
Baseline	1.60	8.5	1.03	8.8	$0.00
EL 1	1.72	8.0	1.13	8.3	3.00

D. Markups Analysis

The markups analysis develops appropriate markups in the distribution chain to convert the estimates of manufacturer cost derived in the engineering analysis to consumer prices. At each step in the distribution channel, companies mark up the price of the product to cover business costs and profit margin. For clothes washers, the main parties in the distribution chain are manufacturers and retailers.

DOE developed an average manufacturer markup by examining the annual Securities and Exchange Commission (SEC) 10–K reports filed by publicly traded manufacturers primarily engaged in appliance manufacturing and whose combined product range includes residential clothes washers.

For retailers, DOE developed separate markups for baseline products (baseline markups) and for the incremental cost of more efficient products (incremental markups). Incremental markups are coefficients that relate the change in the manufacturer sales price of higher-efficiency models to the change in the retailer sales price. DOE relied on economic data from the U.S. Census Bureau to estimate average baseline and incremental markups.[21]

Chapter 6 of the direct final rule TSD provides details on DOE's development of markups for residential clothes washers.

E. Energy and Water Use Analysis

DOE's energy and water use analysis estimated the energy and water use of clothes washers in the field, *i.e.,* as they are actually used by consumers. The energy and water use analysis provided the basis for other analyses DOE performed, particularly assessments of the energy and water savings and the savings in consumer operating costs that could result from DOE's adoption of amended standards. In contrast to the DOE test procedure, which provides standardized results that can serve as the basis for comparing the performance of different appliances used under the same conditions, the energy and water use analysis seeks to capture the range of operating conditions for clothes washers in U.S. homes.

To determine the field energy and water use of products that would meet possible amended standard levels, DOE used data from the Energy Information Administration (EIA)'s 2005 Residential Energy Consumption Survey (RECS), which was the most recent such survey available at the time of DOE's analysis.[22] RECS is a national sample survey of housing units that collects statistical information on the consumption of and expenditures for energy in housing units along with data on energy-related characteristics of the housing units and occupants. RECS provides sufficient information to establish the type (product class) of clothes washer used in each household. As a result, DOE was able to develop household samples for each of the considered product classes. RECS is the only source that provides a nationally representative household sample that includes estimates of usage by clothes washers.

For each sample household, DOE estimated the field-based annual energy and water use of front- and top-loading standard-capacity clothes washers by multiplying the annual number of clothes washer cycles for each household by the per-cycle energy and water use values established by the engineering analysis (using the DOE test procedure) for each considered efficiency level. Per-cycle clothes washer energy use is calculated in the test procedure as the sum of per-cycle machine energy use of the washer (including the energy used to heat water and remove moisture from clothing, and standby and off-mode energy use.

During the framework document public meeting, Whirlpool stated that although RECS has its limitations, there

[21] U.S. Census, 2002 Business Expenditure Survey (BES), Electronics and Appliance Stores sectors.

[22] For information on RECS, see *www.eia.doe.gov/emeu/recs/.*

is no alternative for characterizing the annual energy use of clothes washers. (Whirlpool, No. 22 at p. 7) AHAM, ALS, and GE expressed support for DOE's plan to use RECS as a primary source of information for estimating the energy consumption of clothes washers. (AHAM, No. 16 at p. 6; ALS, No. 13 at p. 10; GE, No. 20 at p. 1)

A more detailed description of DOE's energy and water use analysis for clothes washers is contained in chapter 7 of the direct final rule TSD.

1. Clothes Washer Usage

Commenting on the framework document, AWE said that average wash cycles per year are decreasing. (AWE, No. 12 at p. 3) AHAM stated that DOE should reduce the assumed average number of loads to reflect current data. (AHAM, No. 7 at p. 115) The Joint Comment said that DOE must update the average number of use cycles based on current data. (Joint Comment, No. 15 at p. 5)

Data collected from the 2005 RECS indicate that the frequency of clothes washer use has decreased compared to the assumptions incorporated in DOE's previous test procedure. The average usage value obtained from RECS is 295 cycles per year.[23] Data collected by DOE from the AHAM Fact Book 2005, American Housing Survey (AHS) 2007, and 2006 data provided by Proctor and Gamble[24] confirmed the data on average wash cycles from RECS. More recent nationally-representative data were not available. It is important to note that DOE uses the actual usage for each household sampled in its energy use analysis, not the average usage.

AWE said that DOE should consider that average washer capacity is increasing. (AWE, No. 12 at p. 3) The new DOE test procedure, which was used for estimating per cycle clothes washer energy use, considers recent data on the clothes load in calculating energy use to remove moisture from clothing. The load is a weighted average that depends on load usage factors and the capacity of the clothes washer.

2. Rebound Effect

In calculating energy consumption of residential clothes washers, DOE considered whether it would be appropriate to include a rebound effect (also called a take-back effect), which represents the increased energy consumption that can result from increases in energy efficiency and the associated reduction in operating costs. The rebound effect assumes that consumers will increase their overall annual usage of a more efficient product, thereby decreasing their overall annual savings. Samsung, AHAM, and GE said that they are unaware of a rebound effect for residential clothes washers. (Samsung, No. 25 at p. 5; AHAM, No. 16 at p. 6; GE, No. 20 at p. 1) Whirlpool stated that it is unaware of any data indicating that consumers would purchase a larger clothes washer than their needs dictated. (Whirlpool, No. 22 at p. 7)

A recent review of empirical estimates of the direct rebound effect[25] found one study of direct rebound effects for clothes washing. This study found that the demand for clean clothes (measured as weight of clothes) increased by 5.6% after consumers received new (more efficient) washers.[26] This rebound effect results in part from savings in water and detergent costs. If the estimate was based solely on the savings in the energy costs of the service, the estimated effect would be smaller. DOE does not believe that this study supports include a rebound effect in today's direct final rule, however, because the study used field data from participants who received high-efficiency clothes washers free of charge and was short-term in nature—roughly 3 months of use with the new washers. These factors could contribute to the increase in clothes washed. Lastly, the field trial was in a very small town and included 103 participants, which may not be representative of the U.S. household population.

Based on the above considerations and the comments by manufacturers, DOE did not include a direct rebound effect in its analysis of residential clothes washer energy and water use. However, DOE did perform a sensitivity analysis assuming a 5-percent rebound effect.

F. Life-Cycle Cost and Payback Period Analysis

DOE conducted LCC and PBP analyses to evaluate the economic impacts on individual consumers of potential energy conservation standards for clothes washers. The LCC is the total consumer expense over the life of a product, consisting of purchase and installation costs plus operating costs (expenses for energy use, maintenance, and repair). To compute the operating costs, DOE discounts future operating costs to the time of purchase and sums them over the lifetime of the product. The PBP is the estimated amount of time (in years) it takes consumers to recover the increased purchase cost (including installation) of a more efficient product through lower operating costs. DOE calculates the PBP by dividing the change in purchase cost (normally higher) due to a more stringent standard by the change in average annual operating cost (normally lower) that results from the standard.

For any given efficiency level, DOE measures the PBP and the change in LCC relative to an estimate of the base-case appliance efficiency levels. The base-case estimate reflects the market in the absence of new or amended energy conservation standards, including the market for products that exceed the current energy conservation standards.

For each considered efficiency level in each product class, DOE calculated the LCC and PBP for a nationally representative set of housing units. For the analysis for today's rule, DOE developed household samples from the 2005 RECS. For each sample household, DOE determined the energy consumption for the clothes washer and the appropriate electricity price. By developing a representative sample of households, the analysis captured the variability in energy consumption and energy prices associated with the use of residential clothes washers.

Inputs to the calculation of total installed cost include the cost of the product—which includes manufacturer costs, manufacturer markups, retailer and distributor markups, and sales taxes—and installation costs. Inputs to the calculation of operating expenses include annual energy consumption, energy and water prices and price projections, repair and maintenance costs, product lifetimes, discount rates, and the year that compliance with standards is required. DOE created distributions of values for product lifetime, discount rates, and sales taxes, with probabilities attached to each value, to account for their uncertainty and variability.

The computer model DOE uses to calculate the LCC and PBP, which incorporates Crystal Ball (a commercially available software program), relies on a Monte Carlo simulation to incorporate uncertainty and variability into the analysis. The Monte Carlo simulations randomly

[23] In the TP final rule, DOE changed the representative number of wash cycles per year from 392 to 295 based on the 2005 RECS data. (77 FR 13888)

[24] Procter and Gamble. Study #US064358: Drying Habits. Unpublished PowerPoint Deck. Procured through personal communication with author Cindy Garner, 7/21/2009.

[25] S. Sorrell, J. Dimitropoulos, and M. Sommerville, Empirical estimates of the direct rebound effect: a review, *Energy Policy* 37 (2009), pp. 1356–71.

[26] L.W. Davis, Durable Goods and Residential Demand for Energy and Water: Evidence from a Field Trial, Department of Economics, University of Michigan (2007).

sample input values from the probability distributions and clothes washer user samples. The model calculated the LCC and PBP for products at each efficiency level for 10,000 housing units per simulation run.

Several interested parties supported DOE's use of Monte Carlo simulation to account for variability and uncertainty in inputs to the LCC and PBP analysis. (AHAM, No. 16 at p. 6; ALS, No. 13 at p. 10; GE, No. 20 at p. 1; Samsung, No. 25 at p. 5; Whirlpool, No. 22 at p. 8)

Table IV–18 summarizes the approach and data DOE used to derive inputs to the LCC and PBP calculations. The subsections that follow provide further discussion. Details of the spreadsheet model, and of all the inputs to the LCC and PBP analyses, are contained in chapter 8 and its appendices of the direct final rule TSD.

TABLE IV–18—SUMMARY OF INPUTS AND METHODS FOR THE LCC AND PBP ANALYSIS *

Inputs	Method
Product Cost	Derived by multiplying manufacturer cost by manufacturer and retailer markups and sales tax, as appropriate. Used historical data to derive a price scaling index to forecast product costs.
Installation Costs	Assumed no change with efficiency level.
Annual Energy Use	Used DOE test procedure with data on cycles from the 2005 RECS, market data on RMC, and load weights from test procedure. Used IMEF and IWF to account for self-cleaning, steam cleaning and non-active mode power usage.
Energy and Water Prices	Electricity: Based on EIA's Form 861 data for 2008. Variability: Regional energy prices determined for 13 regions. Water: Based on 2008 AWWA/Raftelis Survey. Variability: By census region.
Energy and Water Price Trends	Energy: Forecasted using *Annual Energy Outlook 2010* (*AEO2010*) price forecasts. Water: Forecasted using BLS historic water price index information.
Repair and Maintenance Costs	Assumed no change with efficiency level.
Product Lifetime	Estimated using survey results from RECS (1990, 1993, 1997, 2001, 2005) and the U.S. Census American Housing Survey (2005, 2007), along with historic data on appliance shipments. Variability: Characterized using Weibull probability distributions.
Discount Rates	Approach involves identifying all possible debt or asset classes that might be used to purchase the considered appliances, or might be affected indirectly. Primary data source was the Federal Reserve Board's SCF ** for 1989, 1992, 1995, 1998, 2001, 2004 and 2007.
Compliance Date	2015.

* References for the data sources mentioned in this table are provided in the sections following the table or in chapter 8 of the direct final rule TSD.

** Survey of Consumer Finances.

1. Product Cost

To calculate consumer product costs, DOE multiplied the manufacturer selling prices developed in the engineering analysis by the supply-chain markups described above (along with sales taxes). DOE used different markups for baseline products and higher-efficiency products, because DOE applies an incremental markup to the increase in MSP associated with higher-efficiency products. ALS supported DOE's approach, as it was employed for estimating future retail prices in other appliance rulemakings. (ALS, No. 13 at p. 10)

Examination of historical price data for a number of appliances that have been subject to energy conservation standards indicates that an assumption of constant real prices and costs may overestimate long-term trends in appliance prices. Economic literature and historical data suggest that the real costs of these products may in fact trend downward over time according to ''learning'' or ''experience'' curves. On February 22, 2011, DOE published a Notice of Data Availability (NODA, 76 FR 9696) stating that DOE may consider improving regulatory analysis by addressing equipment price trends. In the NODA, DOE proposed that when sufficiently long-term data are available on the cost or price trends for a given product, it would analyze the available data to forecast future trends.

Many commenters were supportive of DOE moving from an assumption-based equipment price trend forecasting method to a data-driven methodology for forecasting price trends. Other commenters were skeptical that DOE could accurately forecast price trends given the many variables and factors that can complicate both the estimation and the interpretation of the numerical price trend results and the relationship between price and cost. DOE evaluated these concerns and determined that retaining the assumption-based approach of a constant real price trend was not consistent with the historical data available for residential clothes washers.

In its analysis for today's notice, DOE performed an exponential fit on historical Producer Price Index (PPI) data for household laundry equipment from the Bureau of Labor Statistics' (BLS). (PPI data specific to residential clothes washers were not available.) The PPI data used cover the period 1991–2010. An inflation-adjusted price index for household laundry equipment was calculated by dividing the PPI series by the GDP price deflator for the same years. DOE forecast a price factor index using this exponential model.[27] The value for 2015 used in the LCC and PBP analysis is 0.882. Thus, product prices forecast for the LCC and PBP analysis are equal to 0.882 times the 2010 values for each efficiency level in each product class. DOE's forecast of product prices for clothes washers is described in further detail in appendix 8–E of the direct final rule TSD.[28]

[27] For the NIA, DOE also considered several alternative price trends consistent with the available data as sensitivity cases (see section IV.G.4).

[28] DOE recognizes that its price trend forecasting methods are likely to be modified as more data and information becomes available to enhance the statistical certainty of the trend estimate and the completeness of the model. Additional data should enable an improved evaluation of the potential impacts of more of the factors that can influence product price trends over time.

2. Installation Cost

Installation cost includes labor, overhead, and any miscellaneous materials and parts needed to install the product. DOE found no evidence that installation costs would be impacted with increased efficiency levels, so it did not include installation costs in its analysis.

3. Annual Energy Consumption

For each sampled household, DOE determined the energy consumption for a clothes washer at different efficiency levels using the approach described above in section IV.E.

4. Energy Prices

DOE derived average annual energy prices for 13 geographic areas consisting of the nine U.S. Census divisions, with four large states (New York, Florida, Texas, and California) treated separately. For Census divisions containing one of those large states, DOE calculated the regional average excluding the data for the large state.

DOE calculated average residential electricity prices for each of the 13 geographic areas using data from EIA's Form EIA–861 database (based on ''Annual Electric Power Industry Report'').[29] DOE calculated an average annual regional residential price by: (1) Estimating an average residential price for each utility (by dividing the residential revenues by residential sales); and (2) weighting each utility by the number of residential consumers it served in that region. The final rule analysis used the data for 2008, the most recent data available.

The Joint Comment stated that DOE should consider using regionally based, top-tier residential electricity prices rather than average rates because energy savings would occur at the highest rate the consumer might pay. The California Utilities stated that DOE's analysis should capture the value of energy over time. They pointed to California's use of time-dependent valuation of savings (TDV), which places a high value on energy savings that occur during high cost times of the day and year. (California Utilities, No. 19 at p. 6) ALS supported DOE's approach because has been employed for estimating current and forecasted energy prices in other appliance rulemakings. (ALS, No. 13 at p. 10)

DOE did not use marginal (*i.e.,* top-tier) electricity prices in the current analysis, because for an appliance such as a residential clothes washer, there is little difference between marginal and average electricity prices. The effect of ascending block rates, used by many utilities, is offset by two other features of rate structures: (1) Residential consumers tend to pay relatively high fixed charges, which raises the average price relative to the marginal energy price; and (2) seasonal rates also are common, with summer rates typically higher, and winter rates lower, than the average (this may be reversed in winter-peaking regions). Because clothes washer energy use is not seasonal, over the year the rate differences average out. DOE's analysis of the Edison Electric Institute's Typical Bills and Average Rates Reports for summer and winter 2008 confirms that, when averaged over the year and over a wide consumer base, as is appropriate for clothes washers, marginal and average rates are approximately equal.

5. Energy Price Projections

To estimate energy prices in future years, DOE multiplied the average regional energy prices discussed in section IV. F.4 by the forecasts of annual average residential energy price changes in the Reference case from *AEO2010,* which has an end year of 2035.[30] To estimate price trends after 2035, DOE applied the average annual rate of change in the *AEO2010 forecasts* from 2020 to 2035. The rates used were 1.14 percent for electricity price and 1.16 percent for natural gas price.

6. Water and Wastewater Prices

For today's direct final rule, DOE obtained data on water and wastewater prices for 2010 from the Water and Wastewater Rate Survey conducted by Raftelis Financial Consultants and the water utility association, AWWA. The survey, which analyzes each industry separately, covers approximately 308 water utilities and 228 wastewater utilities. The water survey includes, for each utility, the cost to consumers of purchasing a given volume of water or treating a given volume of wastewater. The data provide a division of the total consumer cost into fixed and volumetric charges. DOE's calculations use only the volumetric charge to calculate water and wastewater prices, because only this charge is affected by a change in water use. Average water and wastewater prices were estimated for each of four census regions. Each RECS household was assigned a water and wastewater price depending on its census region location.

Commenting on the framework document, AWWA stated that the Water and Wastewater Survey conducted by Raftelis and AWWA is the best available national survey of water and wastewater rates. AWWA also noted additional steps that DOE can take to make its incorporation of available water and sewer rates more robust. These include considering base charges that are embedded in the cost of customer service; capturing differences in rate structures at the community level; and accounting for variability in rate structures due to asset management systems at some utilities. (AWWA, No. 14 at p. 3)

In response, DOE believes, as stated above, that using only the volumetric charge to calculate water and wastewater prices is appropriate, because only this charge is affected by a change in water use. DOE was not able to capture differences and variability in rate structures to the degree suggested by AWWA because the Water and Wastewater Rate Survey does not have a large enough number of utilities to allow DOE to develop prices at a level more detailed than the Census region.

AWWA stated that while it is difficult to fully capture the true future cost of water in a national analysis, reliance on a simple extrapolation of current rate structures alone is inadequate. It suggested that DOE account for the need of water and wastewater systems to increase rates in the next 30 to 50 years as systems age. (AWWA, No. 14 at p. 2–3) DOE is not aware of any national-level long-term forecasts of water and wastewater prices. To forecast water and wastewater price trends, DOE used a price index for water and sewerage maintenance from the Bureau of Labor Statistics (BLS), and then adjusted the index for inflation using the Consumer Price Index. DOE developed a price trend based on 45 years of BLS data from 1975 to 2010.

DOE also used price information for households that use well water and a septic tank from the National Ground Water Association, as well as national cost data on residential septic systems from the National Onsite Wastewater Recycling Association (NOWRA).

Chapter 8 of the direct final rule TSD provides more detail about DOE's approach to developing water and wastewater prices.

7. Maintenance and Repair Costs

Repair costs are associated with repairing or replacing components that have failed in an appliance; maintenance costs are associated with maintaining the operation of the product. Typically, small incremental

[29] Available at: *www.eia.doe.gov/cneaf/electricity/page/eia861.html.*

[30] U.S. Energy Information Administration. *Annual Energy Outlook 2010.* Washington, DC. April 2010.

increases in product efficiency produce no, or only minor, changes in repair and maintenance costs compared to baseline efficiency products. In its preliminary analysis, DOE did not have information suggesting that those costs would change with higher efficiency levels.

AHAM and GE stated that information obtained from clothes washer manufacturers indicates that where higher efficiencies are provided via a different configuration (horizontal axis compared to vertical axis), the costs of maintenance and repair increase. (AHAM, No. 16 at p. 7; GE, No. 20 at p. 1) BSH stated that because front-loading units often are installed stacked with the dryer on top of the washer or built into cabinetry, a greater effort is required to access the appliances to perform service. (BSH, No. 11 at p. 6) Miele stated that there can be a higher repair cost for apartment-size front-loaders because they must be removed from the stacked installation to do the repair. (Miele, Public Meeting Transcript, No. 7 at p. 130) ALS suggested that high efficiency technologies may have greater frequency of maintenance. (ALS, No. 13 at p. 10) Whirlpool said that maintenance, repair, and installation costs could be twice current levels if exotic new technologies are required to meet new efficiency levels. (Whirlpool, No. 22 at p. 8) ASAP said that claims of significantly higher repair costs for front-loading machines must be evaluated critically and that recent data for front-loaders should be used. (ASAP, No. 14 at p. 6) Samsung agreed with the view that there is negligible difference in maintenance, repair, and installation costs for baseline and high efficiency units. (Samsung, No. 25 at p. 6)

DOE does not have any data indicating increases in maintenance and repair costs associated with the efficiency levels within each of the product classes considered in its analysis. (Differences in such costs between top- and front-loading washers are not relevant to the LCC analysis.) Therefore, DOE did not assume that more efficient washers in each product class would have greater repair or maintenance costs.

8. Product Lifetime

Because the lifetime of appliances varies depending on utilization and other factors, DOE develops a distribution of lifetimes from which specific values are assigned to the appliances in the samples. In the previous rulemaking for clothes washers, DOE estimated an average product lifetime of 14.1 years. 66 FR 3314.

Commenting on the framework document, AHAM and GE stated that DOE's estimate of 14 years overstates the average useful life of horizontal-axis products. They stated that, based on AHAM data, the average useful life of top-loading configurations is 14 years, while that of front-loading configurations is 11 years. (AHAM, No. 16 at p. 7; GE, No. 20 at p. 1) Samsung supported using DOE's estimated useful life of 14.1 years. (Samsung, No. 25 at p. 6) Whirlpool stated that the September 2008 issue of *Appliance* magazine cites an average life of 11 years, which is consistent with their experience. (Whirlpool, No. 22 at p. 8) ALS supported using an average product lifetime of 14 years, but for only the traditional top-loading models. They said that front-loading and new high efficiency top-loading designs may have shorter lifetimes because of greater design complexity, electronic components that are more expensive to repair, complaints about mold in door boot/seals, and issues concerning out-of-balance spin. (ALS, No. 13 at p. 11) The Joint Comment said that claims of substantially shorter product lifetimes for front-loaders must be evaluated critically. (Joint Comment, No. 15 at p. 6)

To substantiate the estimates for residential clothes washer lifetimes in the literature, DOE conducted an analysis of standard-capacity residential clothes washer lifetimes in the field based on a combination of shipments data and RECS 2005 data on the ages of the clothes washer products reported in the household stock. As described in chapter 8 of the direct final rule TSD, the analysis yielded an estimate of mean age for standard-capacity residential clothes washers of approximately 14.2 years. It also yielded a survival function that DOE incorporated as a probability distribution in its LCC analysis. Because the RECS data do not indicate whether the washer has top-loading or front-loading configuration, DOE was not able to derive separate lifetime estimates for these two product classes. DOE did not receive any data or analysis to support separate lifetimes for the different product classes.

See chapter 8 of the direct final rule TSD for further details on the method and sources DOE used to develop product lifetimes.

9. Discount Rates

In the calculation of LCC, DOE applies discount rates to estimate the present value of future operating costs. DOE estimated separate distributions of residential discount rates for clothes washers purchased as replacements and for washers purchased in new homes. To establish residential discount rates for the LCC analysis, DOE identified all debt or asset classes that might be used to purchase clothes washers, including household assets that might be affected indirectly. It estimated the average percentage shares of the various debt or asset classes for the average U.S. household using data from the Federal Reserve Board's *Survey of Consumer Finances* (SCF) for 1989, 1992, 1995, 1998, 2001, 2004, and 2007. Using the SCF and other sources, DOE then developed a distribution of rates for each type of debt and asset to represent the rates that may apply in the year in which amended standards would take effect. DOE assigned each sample household a specific discount rate drawn from one of the distributions. The average inflation-adjusted rate across all types of household debt and equity, weighted by the shares of each class, is 5.1 percent. DOE used the same approach for today's direct final rule. See chapter 8 in the direct final rule TSD for further details on the development of consumer discount rates.

10. Compliance Date of Amended Standards

In the context of EPCA, the compliance date is the future date when parties subject to the requirements of a new standard must comply. If no adverse comments are received in response to the direct final rule that may provide a reasonable basis for withdrawal under 42 U.S.C. 6295(o) or other applicable law, compliance with amended standards for residential clothes washers will be required on March 7, 2015. DOE calculated the LCC and PBP for clothes washers as if consumers would purchase new products in 2015. In the case of TSL 3, which includes a second set of standards for top-loading standard clothes washers that would require compliance on January 1, 2018, DOE calculated separate LCC and PBP for clothes washers meeting these standards and purchased in 2018.

11. Base-Case Efficiency Distribution

To accurately estimate the share of consumers that would be affected by a standard at a particular efficiency level, DOE's LCC analysis considered the projected distribution of product efficiencies that consumers purchase under the base case (*i.e.,* the case without new energy efficiency standards). DOE refers to this distribution of product efficiencies as a base-case efficiency distribution. DOE relied on data submitted by AHAM to estimate the base-case efficiency distributions for each of the product classes that were analyzed in the LCC and PBP analysis. To project the efficiency distributions in 2015, DOE considered the 2006–2008 trends and the potential effect of programs such as ENERGY STAR.

For front-loading clothes washers, the data from AHAM show some increase in the share of higher efficiency levels between 2006 and 2008. However, by 2008 over 95 percent of the front-loading clothes washer market was already at or above the 2011 ENERGY STAR criteria (Efficiency Level 4). Therefore, DOE believes that the ENERGY STAR qualification requirements are likely to have a limited impact in further expanding the market shares of higher efficiency front-loading clothes washers. Based on the above considerations, DOE assumed that the 2008 market shares would remain constant through 2015.

For top-loading clothes washers, the data from AHAM show an increase in the share of medium- and high-efficiency levels (Efficiency Levels 2–8) from 6.3 percent in 2006 to 8.5 percent in 2008. To estimate a trend from 2008 to 2015, DOE fit an exponential curve to the three data points that suggests the growth in share would level off at around 20 percent. The estimated total share of the medium- and high-efficiency levels in 2015 is 19.2 percent. DOE then disaggregated this total share into shares of specific levels using assumptions described in chapter 8 of the direct final rule TSD.

Table IV–19 shows the 2015 base-case efficiency distribution for top-loading and front-loading clothes washers.

TABLE IV–19—BASE-CASE EFFICIENCY DISTRIBUTION BY PRODUCT CLASS

Efficiency level	Top-loading standard size (percent)	Front-loading standard size (percent)	Top-loading compact size (percent)	Front-loading compact size (percent)
Baseline	40.4	0.0	100.0	100.0
1	40.4	0.0	0.0	0.0
2	2.8	0.0	0.0	
3	0.9	4.3		
4	0.9	24.0		
5	0.9	48.9		
6	9.1	11.4		
7	4.6	11.4		
8	0.0	0.0		

12. Inputs to Payback Period Analysis

The payback period is the amount of time it takes the consumer to recover the additional installed cost of more efficient products, compared to baseline products, through energy cost savings. Payback periods are expressed in years. Payback periods that exceed the life of the product mean that the increased total installed cost is not recovered in reduced operating expenses.

The inputs to the PBP calculation are the total installed cost of the product to the customer for each efficiency level and the average annual operating expenditures for each efficiency level. The PBP calculation uses the same inputs as the LCC analysis, except that discount rates are not needed.

13. Rebuttable-Presumption Payback Period

As noted above, EPCA, as amended, establishes a rebuttable presumption that a standard is economically justified if the Secretary finds that the additional cost to the consumer of purchasing a product complying with an energy conservation standard level will be less than three times the value of the energy (and, as applicable, water) savings during the first year that the consumer will receive as a result of the standard, as calculated under the test procedure in place for that standard. (42 U.S.C. 6295(o)(2)(B)(iii)) For each considered efficiency level, DOE determined the value of the first year's energy and water savings by calculating the quantity of those savings in accordance with the applicable DOE test procedure, and multiplying that amount by the average energy and water price forecast for the year in which compliance with the amended standard would be required. The results of the rebuttable payback period analysis are summarized in section V.B.1.c of this notice.

G. National Impact Analysis—National Energy Savings and Net Present Value Analysis

The national impact analysis (NIA) assesses the national energy savings (NES) and the national net present value (NPV) of total consumer costs and savings that would be expected to result from new or amended standards at specific efficiency levels. (''Consumer'' in this context refers to consumers of the product being regulated.) DOE calculates the NES and NPV based on projections of annual appliance shipments, along with the annual energy consumption and total installed cost data from the energy use and LCC analyses. For the present analysis, DOE forecasted the energy savings, operating cost savings, product costs, and NPV of consumer benefits for products sold from 2015 through 2044.

DOE evaluates the impacts of new and amended standards by comparing base-case projections with standards-case projections. The base-case projections characterize energy use and consumer costs for each product class in the absence of new or amended energy conservation standards. DOE compares these projections with projections characterizing the market for each product class if DOE adopted new or amended standards at specific energy efficiency levels (*i.e.,* the TSLs or standards cases) for that class. For the base-case forecast, DOE considers historical trends in efficiency and various forces that are likely to affect the mix of efficiencies over time. For the standards cases, DOE also considers how a given standard would likely affect the market shares of efficiencies greater than the standard.

DOE uses an MS Excel spreadsheet model to calculate the energy savings and the national consumer costs and savings from each TSL. The TSD and other documentation that DOE provides during the rulemaking help explain the models and how to use them, and interested parties can review DOE's analyses by changing various input quantities within the spreadsheet. The NIA spreadsheet model uses typical values (as opposed to probability distributions) as inputs.

For the results presented in today's notice, DOE used projections of energy prices and housing starts from the *AEO2010* Reference case. The Joint Comment stated that electricity prices should be subject to a sensitivity analysis and forecasts other than *AEO*. (Joint Comment, No. 15 at p. 5) As part of the NIA, DOE analyzed scenarios that used inputs from the *AEO2010* Low Economic Growth and High Economic Growth cases. Those cases have higher and lower energy price trends compared to the Reference case, as well as higher and lower housing starts, which result in higher and lower appliance shipments to new homes. NIA results based on these cases are presented in appendix 10–A of the direct final rule TSD. The range of forecasts in *AEO2010* is sufficiently broad that using other long-range energy forecasts would not provide added value to the sensitivity analysis.

Table IV–20 summarizes the inputs and methods DOE used for the NIA analysis for the direct final rule. Discussion of these inputs and methods follows the table. See chapter 10 of the direct final rule TSD for further details.

TABLE IV–20—SUMMARY OF INPUTS AND METHODS FOR THE NATIONAL IMPACT ANALYSIS

Inputs	Method
Shipments	Annual shipments from shipments model.
Compliance Date of Standard	2015.*
Base-Case Forecasted Efficiencies	Efficiency distributions are maintained unchanged during the forecast period.
Standards-Case Forecasted Efficiencies	Used a "roll-up" scenario for most efficiency levels and a "shift" scenario for highest efficiency levels.
Annual Energy Consumption per Unit	Annual weighted-average values as a function of IMEF.**
Total Installed Cost per Unit	Annual weighted-average values as a function of IMEF.**
	Incorporates forecast of future product prices based on historical data.
Annual Energy Cost per Unit	Annual weighted-average values as a function of the annual energy consumption per unit and energy prices.
Repair and Maintenance Cost per Unit	Annual values as a function of efficiency level.
Energy Prices	*AEO2010* forecasts (to 2035) and extrapolation through 2044.
Energy Site-to-Source Conversion Factor	Varies yearly and is generated by NEMS–BT.
Discount Rate	Three and seven percent real.
Present Year	Future expenses discounted to 2011, when the final rule will be published.

* For TSL 3, which includes two sets of standards for top-loading standard clothes washers, the compliance date for the second set of standards is in 2018.

** IMEF = integrated modified energy factor, which includes the energy used in the active, standby, and off modes.

1. Shipments

Forecasts of product shipments are needed to calculate the national impacts of standards on energy and water use, NPV, and future manufacturer cash flows. DOE develops shipment forecasts based on an analysis of key market drivers for residential clothes washers. In DOE's shipments model, shipments of products are driven by new construction and stock replacements. The shipments model takes an accounting approach, tracking market shares of each product class and the vintage of units in the existing stock. Stock accounting uses product shipments as inputs to estimate the age distribution of in-service product stocks for all years. The age distribution of in-service product stocks is a key input to calculations of both the NES and NPV, because operating costs for any year depend on the age distribution of the stock. DOE also considers the impacts on shipments from changes in product purchase price and operating cost associated with higher energy efficiency levels.

To forecast shipments under the base case, DOE utilized historical shipments data submitted by AHAM disaggregated by product class. AHAM and GE noted that they could not provide data on compact top-loading products given the few manufacturers and the resulting inability to aggregate the data. (AHAM, No. 16 at p. 8; GE, No. 20 at p. 1)

AWE suggested that DOE consider the trend in multi-family housing toward in-unit washers and away from common-area clothes washers. (AWE, No. 12 at p. 3) DOE considered trends away from common-area clothes washers in multi-family housing by looking at changes in the numbers of households with clothes washers. DOE used the data contained in the 2005 RECS to characterize ownership of residential clothes washers and usage in households of various types, including multi-family housing. For future trends, DOE captured in-unit washers within multi-family housing by estimating future clothes washer saturations in all new residential construction, including multi-family housing.

To estimate the effects on product shipments from increases in product price projected to accompany amended standards at higher efficiency levels, DOE applied a cross-price elasticity. Cross-price impacts measure the change in the market share of one washer configuration (*e.g.,* top loaders) caused by a change in the price of the other washer configuration (*e.g.,* front loaders). DOE estimated a logistic regression model equation that derives the relative probability of the market share of top- and front- loading clothes washers as a function of the monthly sales-weighted average price of top-loaders and front-loaders and the ratio of the monthly sales-weighted average of front-loader tub volume to the monthly sales-weighted average of top-loader tub volume. The equation indicates that front loader market share is positively correlated with top loader price and size and negatively correlated with front loader price. The regression results were used to derive the cross price impact of a change in the top-loading washer price on the front-loader market share (and vice versa).

DOE also applied a price elasticity parameter to estimate the effect of standards on each product class by itself. DOE estimated the price elasticity parameter using a regression analysis that used purchase price and efficiency data specific to residential clothes washers, as well as residential refrigerators and dishwashers, during 1980–2002. The estimated ''relative price elasticity'' incorporates the impacts from purchase price, operating cost, and household income, and it also declines over time. DOE estimated shipments in each standards case using the relative price elasticity along with the change in the relative price between a standards case and the base case.

For details on the shipments analysis, see chapter 9 of the direct final rule TSD.

2. Forecasted Efficiency in the Base Case and Standards Cases

A key component of the NIA is the trend in energy efficiency forecasted for the base case (without new or amended standards) and each of the standards cases. Section IV.F.11 described how DOE developed a base-case energy efficiency distribution (which yields a shipment-weighted average efficiency) for each of the considered product classes for the first year of the forecast period. To project the trend in efficiency over the entire forecast period, DOE considered recent trends and the potential effect of programs such as ENERGY STAR. As discussed in section IV.F.11, DOE did not find a basis for projecting an increase in the average efficiency of front-loading clothes washers. For top-loading clothes washers, DOE assumed that the growth in share of the medium- and high-efficiency levels would level off at around 20 percent. Although there is room for the shares of the higher efficiency levels to grow, DOE believes that the growth will be constrained by the likelihood that consumers with a strong interest in energy efficiency will purchase front-loading clothes washers instead of top-loading clothes washers.

The historical record suggests that the likely market response to new or amended standards is that lower efficiency baseline models will roll up to the standard efficiency level, and some products will exceed the minimum requirements. To estimate efficiency trends in the standards cases, DOE has used ''roll-up'' and/or ''shift'' scenarios in its standards rulemakings. Under the ''roll-up'' scenario, DOE assumes: (1) Product efficiencies in the base case that do not meet the standard level under consideration would ''roll-up'' to meet the new standard level; and (2) product efficiencies above the standard level under consideration would not be affected. Under the ''shift'' scenario, DOE re-orients the distribution above the new minimum energy conservation standard.

For the direct final rule, DOE primarily used a roll-up scenario to establish the distribution of efficiencies for the year that compliance with revised standards would be required and for subsequent years. It also considered the potential impacts of the ENERGY STAR program. Because ENERY STAR criteria in 2011 consist of an MEF ≥2.00 and a WF ≤6.0, DOE assumed that the ENERGY STAR program would not affect the front-loader or top-loader market for any new standards set at levels less efficient than the 2011 ENERGY STAR requirements. As a result, for standards set at top-loader efficiency levels 1 through 5 and front-loader efficiency levels 1 through 3, DOE estimated that efficiency distributions would remain unchanged from 2015 through 2044. For any new standards set at efficiency levels that meet the 2011 ENERGY STAR requirements, DOE assumed that the market share of efficiency levels beyond the standard will increase. The level of increase was set equal to the market share change from 2006 to 2008 for the efficiency level directly preceding the standard. Using the above criteria, DOE assumed that from 2015 to 2022 the shipment weighted integrated modified energy factor (SWIMEF) market share would grow linearly. In all cases, because DOE has insufficient information on which to forecast changes in the market beyond 2022, DOE assumed that after 2022 the market would remain unchanged through 2044.

The details of DOE's approach to forecast efficiency trends are described in chapter 10 of the direct final rule TSD.

3. Total Installed Cost per Unit

As discussed in section IV.F.1, in the analysis for today's notice, DOE developed a price trend based on historical PPI data for household laundry equipment. It used this trend to forecast the prices of clothes washers sold in each year in the forecast period (2015–2044). DOE applied the same values to forecast prices for each product class at each considered efficiency level.

To evaluate the impact of the uncertainty of the price trend estimates, DOE investigated the impact of different product price forecasts on the consumer net present value for the considered TSLs for residential clothes washers. DOE considered three product price forecast sensitivity cases: (1) A trend based on the experience curve approach;[31] (2) a trend based on the ''chained price index—other consumer durable goods except ophthalmic'' that was forecasted for *AEO2010;* and (3) constant prices at 2010 levels. The results of these sensitivity cases are described in appendix 10–C of the direct final rule TSD.

4. National Energy and Water Savings

For each year in the forecast period, DOE calculates the national energy and water savings (NES) for each standard level by multiplying the stock of products affected by the energy conservation standards by the per-unit annual energy savings. Cumulative energy and water savings are the sum of the NES for each year.

To estimate the national energy savings expected from appliance standards, DOE uses a multiplicative factor to convert site energy consumption (at the home) into primary or source energy consumption (the energy required to convert and deliver the site energy). These conversion factors account for the energy used at power plants to generate electricity and losses in transmission and distribution. The conversion factors vary over time because of projected changes in generation sources (*i.e.,* the power plant types projected to provide electricity to the country). The factors that DOE developed are marginal values, which represent the response of the system to an incremental decrease in consumption associated with appliance standards. For today's rule, DOE used annual site-to-source conversion factors based on the version of NEMS that corresponds to *AEO2010,* which provides energy forecasts through 2035. For 2036–2044, DOE used conversion factors that remain constant at the 2035 values.

Section 1802 of the Energy Policy Act of 2005 (EPACT 2005) directed DOE to contract a study with the National Academy of Science (NAS) to examine whether the goals of energy efficiency standards are best served by measuring energy consumed, and efficiency improvements, at the actual point of use or through the use of the full-fuel-cycle, beginning at the source of energy production. (Pub. L. 109–58 (August 8, 2005)). NAS appointed a committee on ''Point-of-Use and Full-Fuel-Cycle Measurement Approaches to Energy Efficiency Standards'' to conduct the study, which was completed in May 2009. The NAS committee defined full-fuel-cycle energy consumption as including, in addition to site energy use: Energy consumed in the extraction, processing, and transport of primary fuels such as coal, oil, and natural gas; energy losses in thermal combustion in power generation plants; and energy losses in transmission and distribution to homes and commercial buildings.

[31] In the experience curve method, the real product price (or proxy thereof) is related to the cumulative production or ''experience'' with a product. As experience accumulates, the cost of producing the next unit decreases. The percentage reduction in cost that occurs with each doubling of cumulative production is known as the learning or experience rate. In typical experience curve formulations, the experience rate parameter is derived using two historical data series: Price (or cost) and cumulative production, which is a function of shipments during a long time span.

In evaluating the merits of using point-of-use and full-fuel-cycle measures, the NAS committee noted that DOE uses what the committee referred to as ''extended site'' energy consumption to assess the impact of energy use on the economy, energy security, and environmental quality. The extended site measure of energy consumption includes the energy consumed during the generation, transmission, and distribution of electricity but, unlike the full-fuel-cycle measure, does not include the energy consumed in extracting, processing, and transporting primary fuels. A majority of the NAS committee concluded that extended site energy consumption understates the total energy consumed to make an appliance operational at the site. As a result, the NAS committee recommended that DOE consider shifting its analytical approach over time to use a full-fuel-cycle measure of energy consumption when assessing national and environmental impacts, especially with respect to the calculation of greenhouse gas emissions. The NAS committee also recommended that DOE provide more comprehensive information to the public through labels and other means, such as an enhanced Web site. For those appliances that use multiple fuels (*e.g.,* water heaters), the NAS committee indicated that measuring full-fuel-cycle energy consumption would provide a more complete picture of energy consumed and permit comparisons across many different appliances, as well as an improved assessment of impacts.

In response to the NAS committee recommendations, DOE issued a notice of proposed policy for incorporating a full-fuel cycle analysis into the methods it uses to estimate the likely impacts of energy conservation standards on energy use and emissions. 75 FR 51423 (Aug. 20, 2010). Specifically, DOE proposed to use full-fuel-cycle (FFC) measures of energy and greenhouse gas (GHG) emissions, rather than the primary (extended site) energy measures it currently uses. Additionally, DOE proposed to work collaboratively with the Federal Trade Commission to make FFC energy and GHG emissions data available to the public to enable consumers to make cross-class comparisons. On October 7, 2010, DOE held an informal public meeting to discuss and receive comments on its planned approach. The notice, a transcript of the public meeting, and all public comments received by DOE are available at: *http://www.regulations.gov/#!docketDetail;D=EERE-2010-BT-NOA-0028.* DOE intends to develop a final policy statement on the subject and then take steps to begin implementing that policy in rulemakings and other activities.

a. Accounting for Other Energy Impacts

In the framework document for residential clothes washers, DOE requested comment on the issue of embedded energy (*i.e.,* the energy required for water treatment and delivery). Earthjustice maintained that DOE's legal justification for not considering embedded energy ''ignores that EPCA not only provides ample authority for DOE to consider this impact, but actually commands its consideration in weighing the economic justification for efficiency standards.'' (Earthjustice, No. 17 at p. 10) The California Utilities said that DOE should attempt to address the issue of embedded energy in water in its rulemaking analyses. (California Utilities, No. 19 at p. 5)

In response, DOE notes that EPCA directs DOE to consider (when determining whether a standard is economically justified) ''the total projected amount of energy, or as applicable, water, savings likely to result directly from the imposition of the standard.'' 42 U.S.C. 6295(o)(2)(B)(i)(III) DOE interprets ''directly from the imposition of the standard'' to include energy used in the generation, transmission, and distribution of fuels used by appliances. In addition, DOE is evaluating the full-fuel-cycle measure, which includes the energy consumed in extracting, processing, and transporting primary fuels. Unlike the energy used for water treatment and delivery, both DOE's current accounting of primary energy savings and the full-fuel-cycle measure are directly linked to the energy used by appliances.

Several interested parties commented that DOE's calculation of energy consumption should include the energy used in the manufacture, distribution, and ultimate recycling of residential clothes washers. (AWE, No. 12 at p. 2; Joint Comment, No. 15 at p. 6; Earthjustice, No. 17 at pp. 9–10) Both DOE's current accounting of primary energy savings and the full-fuel-cycle measure are directly linked to the energy used by appliances. The imposition of an energy efficiency standard for residential clothes washers would not lead directly to energy savings in the manufacture, distribution and recycling of clothes washers. DOE believes that any such savings would be both indirect and difficult to determine. Thus, DOE did not consider such energy use in the NIA pursuant to 42 U.S.C. 6295(o)(2)(B)(i)(III).

5. Net Present Value of Consumer Benefit

The inputs for determining the net present value (NPV) of the total costs and benefits experienced by consumers of considered appliances are: (1) Total annual installed cost, (2) total annual savings in operating costs, and (3) a discount factor. DOE calculates net savings each year as the difference between the base case and each standards case in total savings in operating costs and total increases in installed costs. DOE calculates operating cost savings over the life of each product shipped during the forecast period.

In calculating the NPV, DOE multiplies the net savings in future years by a discount factor to determine their present value. For today's direct final rule, DOE estimated the NPV of appliance consumer benefits using both a 3-percent and a 7-percent real discount rate. DOE uses these discount rates in accordance with guidance provided by the Office of Management and Budget (OMB) to Federal agencies on the development of regulatory analysis.[32] The discount rates for the determination of NPV are in contrast to the discount rates used in the LCC analysis, which are designed to reflect a consumer's perspective. The 7-percent real value is an estimate of the average before-tax rate of return to private capital in the U.S. economy. The 3-percent real value represents the ''social rate of time preference,'' which is the rate at which society discounts future consumption flows to their present value.

The California Utilities stated that because 3 percent is closer to the OMB's current estimated 30-year real discount rate, DOE should give primary weight to calculations based on the 3-percent real rate. (California Utilities, No. 19 at p. 6)

DOE notes that OMB Circular A–4 references an earlier Circular A–94, which states that a real discount rate of 7 percent should be used as a base case for regulatory analysis. The 7-percent rate is an estimate of the average before-tax rate of return on private capital in the U.S. economy. It approximates the opportunity cost of capital and, according to Circular A–94, is the appropriate discount rate whenever the primary effect of a regulation is to displace or alter the use of capital in the

[32] OMB Circular A–4 (Sept. 17, 2003), section E, ''Identifying and Measuring Benefits and Costs. Available at: *www.whitehouse.gov/omb/memoranda/m03-21.html.*

private sector. In preparing Circular A–4, OMB found that the average rate of return on capital remains near the 7-percent rate estimated earlier. Circular A–4 also states that when a regulation primarily and directly affects private consumption, a lower discount rate (the social rate of time preference) is appropriate. It suggests that the real rate of return on long-term government debt may provide a fair approximation of the social rate of time preference, and states that during the past 30 years, this rate has averaged about 3 percent in real terms on a pre-tax basis. Circular A–4 concludes that ''for regulatory analysis, [agencies] should provide estimates of net benefits using both 3 percent and 7 percent.'' Consistent with the OMB guidance, for today's rule DOE provided and considered results derived using discount rates of 3 percent and 7 percent.

6. Benefits From Effects of Standards on Energy Prices

Reduction in electricity consumption associated with amended standards for residential clothes washers could reduce the electricity prices charged to consumers in all sectors of the economy and thereby reduce their electricity expenditures.

Commenting on the framework document, the California Utilities stated that the electricity price mitigation effects produced by new standards for clothes washers should be documented and the value of reduced electricity bills to all consumers quantified as a benefit. (California Utilities, No. 19 at p. 6)

For the direct final rule, DOE used NEMS–BT to assess the impacts of the reduced need for new electric power plants and infrastructure projected to result from clothes washer standards. In NEMS–BT, changes in power generation infrastructure affect utility revenue requirements, which in turn affect electricity prices. DOE estimated the impact on electricity prices associated with each considered TSL. Although the aggregate benefits for electricity users are potentially large, there may be negative effects on some of the actors involved in electricity supply, such as actors involved in power plant construction and fuel suppliers. Because there is uncertainty about the extent to which the benefits for electricity users from reduced electricity prices would be a transfer from actors involved in electricity supply to electricity consumers, DOE is continuing to investigate the extent to which electricity price changes projected to result from standards represent a net gain to society.

H. Consumer Subgroup Analysis

In analyzing the potential impact of new or amended standards on consumers, DOE evaluates the impact on identifiable subgroups of consumers (*e.g.,* low-income households) that may be disproportionately affected by a national standard. DOE evaluates impacts on particular subgroups of consumers primarily by analyzing the LCC impacts and PBP for those particular consumers from alternative standard levels. Chapter 11 in the direct final rule TSD describes the consumer subgroup analysis.

In response to the framework document, interested parties requested that DOE consider a number of subgroups for analysis. The Joint Comment said that renters and disabled homeowners should be considered as LCC subgroups. (Joint Comment, No. 15 at p. 6) AHAM and Whirlpool stated that DOE should consider low-income households as a consumer subgroup, because they are affected by the cost increases engendered by efficiency increases. (AHAM, No. 24 at p. 3; Whirlpool, No. 22 at p. 9) ALS supported considering subgroups comprising low-income households and senior citizens. (ALS, No. 13 at p. 12) Whirlpool said that DOE should consider a consumer subgroup comprising families with young children. (Whirlpool, No. 22 at p. 9)

For this rule, DOE analyzed the impacts of the considered standard levels on low-income households and senior-only households. DOE did not examine renters as a subgroup. DOE notes that, in most cases, renters pay the electricity bill but do not own the clothes washer in their home. To some extent, the higher cost of a more-efficient clothes washer incurred by the building owner would likely be passed on to the renter through increased rent. Because DOE is not aware of information that would allow it to reliably assess the extent to which such ''pass-through'' would occur, it was not able to quantitatively analyze the impacts of alternative standard levels on renters. DOE did not consider families with children as a subgroup. To the extent such families have low income, they are already included in the analysis of low-income households. DOE had no information to support the contention that families with children would otherwise be negatively affected by a standard. Lastly, DOE did not have any information with which to analyze disabled people as a subgroup.

I. Manufacturer Impact Analysis

The following sections address the various steps taken to analyze the impacts of the amended standards on manufacturers. These steps include conducting a series of analyses, interviewing manufacturers, and evaluating the comments received from interested parties during this rulemaking.

1. Overview

In determining whether an amended energy conservation standard for residential clothes washers subject to this rulemaking is economically justified, DOE is required to consider ''the economic impact of the standard on the manufacturers and on the consumers of the products subject to such standard.'' (42 U.S.C. 6295(o)(2)(B)(i)(I)) The statute also calls for an assessment of the impact of any lessening of competition as determined by the Attorney General that is likely to result from the adoption of a standard. (42 U.S.C. 6295(o)(2)(B)(i)(V)) DOE conducted the MIA to estimate the financial impact of amended energy conservation standards on manufacturers, and to assess the impacts of such standards on employment and manufacturing capacity.

The MIA is both a quantitative and qualitative analysis. The quantitative part of the MIA relies on the Government Regulatory Impact Model (GRIM), an industry cash-flow model customized for the residential clothes washers covered in this rulemaking. See section IV.I.2 below, for details on the GRIM analysis. The qualitative part of the MIA addresses factors such as product characteristics, characteristics of particular firms, and market trends. The complete MIA is discussed in chapter 12 of the direct final rule TSD. DOE conducted the MIA in the three phases described below.

a. Phase 1, Industry Profile

In Phase 1 of the MIA, DOE prepared a profile of the residential clothes washer industry based on the market and technology assessment prepared for this rulemaking. Before initiating the detailed impact studies, DOE collected information on the present and past market structure and characteristics of the industry, tracking trends in market share, product attributes, product shipments, manufacturer markups, and the cost structure for various manufacturers.

The profile also included a top-down analysis of manufacturers in the industry using Security and Exchange

Commission 10–K filings,[33] Standard & Poor's stock reports,[34] and corporate annual reports released by both public and privately held companies. DOE used this and other publicly available information to derive preliminary financial inputs for the GRIM (*e.g.,* revenues, cost of goods sold, depreciation, SG&A, and research and development (R&D) expenses).

b. Phase 2, Industry Cash Flow Analysis

Phase 2 focused on the financial impacts of potential amended energy conservation standards on the industry as a whole. Amended energy conservation standards can affect manufacturer cash flows in three distinct ways: (1) By creating a need for increased investment, (2) by raising production costs per unit, and (3) by altering revenue due to higher per-unit prices and/or possible changes in sales volumes. DOE used the GRIM to model these effects in a cash-flow analysis of the residential clothes washer industry. In performing this analysis, DOE used the financial values derived during Phase 1 and the shipment assumptions from the NIA.

c. Phase 3, Sub-Group Impact Analysis

Using average cost assumptions to develop an industry-cash-flow estimate may not adequately assess differential impacts of amended energy conservation standards among manufacturer subgroups. For example, small businesses, manufacturers of niche products, or companies exhibiting a cost structure that differs significantly from the industry average could be more negatively affected. During the manufacturer interviews, DOE discussed financial topics specific to each manufacturer and obtained each manufacturer's view of the industry as a whole. DOE reports the MIA impacts of amended energy conservation standards by grouping together the impacts on manufacturers of certain product classes. While DOE did not identify any other subgroup of manufacturers of residential clothes washers that would warrant a separate analysis, DOE specifically investigated impacts on small business manufacturers. See section VI.B for more information.

The MIA also addresses the direct employment impacts in manufacturing of clothes washers. DOE uses census data and information gained through manufacturer interviews in conjunction with the GRIM to estimate the domestic labor expenditures and number of domestic production workers in the base case and at each TSL from 2011 to 2044.

2. GRIM Analysis

DOE uses the GRIM to quantify the changes in cash flow that result in a higher or lower industry value. The GRIM analysis is a standard, annual cash-flow analysis that incorporates manufacturer costs, markups, shipments, and industry financial information as inputs, and models changes in costs, distribution of shipments, investments, and manufacturer margins that could result from amended energy conservation standards. The GRIM spreadsheet uses the inputs to arrive at a series of annual cash flows, beginning with the base year of the analysis, 2011 (which accounts for the investments needed to bring products into compliance), and continuing to 2044. DOE calculated INPVs by summing the stream of annual discounted cash flows during this period. DOE uses the industry average weighted average cost of capital (WACC) of 8.5 percent, as this represents the minimum rate of return necessary to cover the debt and equity obligations manufacturers use to finance operations.

DOE used the GRIM to compare INPV in the base case with INPV at various TSLs (the standards cases). The difference in INPV between the base and standards cases represents the financial impact of the amended standard on manufacturers. DOE collected this information from a number of sources, including publicly available data and interviews with a number of manufacturers. Additional details about the GRIM can be found in chapter 12 of the direct final rule TSD.

a. GRIM Key Inputs

Manufacturer Production Costs

Changes in the manufacturer production costs (MPCs) of residential clothes washers can affect revenues, gross margins, and cash flow of the industry, making these product cost data key GRIM inputs for DOE's analysis. DOE used the MPCs calculated in the engineering analysis for each efficiency level, as described in section IV.C above, and further detailed in chapter 5 of the direct final rule TSD. DOE used the AHAM data submittal to determine the MPCs at most efficiency levels for top-loading and front-loading standard product classes. To supplement the AHAM submittal and calculate max-tech MPCs for these product classes, DOE also conducted product tear downs to generate MPCs using a manufacturing cost model. DOE created separate cost curves for top-loading and front-loading compact product classes using data from tear-downs to develop baseline MPCs and applied the incremental costs that correspond to the proposed design options from the standard product classes. The cost model also disaggregated the MPCs into material, labor, overhead, and depreciation.

Base-Case Shipments Forecast

The GRIM estimates manufacturer revenues based on total unit shipment forecasts and the distribution of these values by efficiency level and product class. Changes in the efficiency mix at each standard level affect manufacturer finances. For this analysis, the GRIM uses the NIA shipments forecasts from 2011 to 2044, the end of the analysis period.

To calculate shipments, DOE developed a single shipment model for all residential clothes washers and disaggregated total shipments into front-loading and top-loading clothes washers, and assigned shipments to both the standard and compact product classes. In the base case, DOE forecasted change in market share of each product class by utilizing historical shipments data submitted by AHAM.

Product and Capital Conversion Costs

Amended energy conservation standards will cause manufacturers to incur conversion costs to bring their production facilities and product designs into compliance. For the MIA, DOE classified these costs into two major groups: (1) Product conversion costs and (2) capital conversion costs. Product conversion costs are investments in research, development, testing, marketing, and other non-capitalized costs focused on making product designs comply with the amended energy conservation standard. Capital conversion costs are investments in property, plant, and equipment to adapt or change existing production facilities so that new product designs can be fabricated and assembled.

DOE based the conversion cost estimates required to meet each TSL on the AHAM data submittal for all product classes. Using the AHAM data submittal for both the product and capital conversion costs ensures that the costs required to meet amended energy conservation standards are consistent with the incremental costs to reach those efficiencies. DOE validated these costs in manufacturer interviews and through the product teardown analysis.

At each top-loading and front-loading standard efficiency level, DOE matched

[33] Available online at *www.sec.gov.*

[34] Available online at *www2.standardandpoors.com.*

the IMEF efficiency level to the corresponding MEF metric and used the aggregated total industry capital and product conversion cost from the May 2010 AHAM submittal. DOE multiplied each aggregated capital and product conversion total for these product classes by 1.05 to account for the non-AHAM member shipments. For the new max-tech levels revised using the AHAM data submittal, DOE scaled the aggregated total conversion costs at the next lowest efficiency level by the same percentage increase in production costs. DOE did not increase the required product and capital conversion costs for efficiency levels that do not contribute to a change in active mode efficiency to ensure that the costs required are consistent with the incremental costs to meet amended energy conservation standards and because, as described in section IV.C.3, the standby power technology options would require minimal product development.

For the top-loading compact product class, DOE scaled the top-loading standard conversion costs for the same efficiency level by the relative number of compact platforms. DOE did not include conversion costs for the front-loading compact product classes because the design options analyzed to improve efficiency would require minimal changes to baseline products.

DOE took a number of steps to analyze the conversion costs in the AHAM data submittal. DOE reviewed the AHAM conversion costs during manufacturer interviews to understand the magnitude and cost of the required conversions for individual manufacturers. DOE also reviewed public information in the CEC, ENERGY STAR, and CEE product databases as well as manufacturer Web sites to understand which product lines manufacturers would need to upgrade at each efficiency level. DOE also reviewed the AHAM submittal in conjunction with the technology options and information learned during product teardowns for multiple product lines.

DOE's estimates of the total capital conversion and production conversion costs by TSL can be found in section V.B.2 of today's direct final rule. The estimates of the total capital conversion and product conversion costs by product class and efficiency level can be found in chapter 12 of the direct final rule TSD.

b. GRIM Scenarios

Standards-Case Shipment Forecasts

The MIA results presented in section V.B.2 all use shipments from the reference NIA scenario in the GRIM. To determine efficiency distributions in the standards case for the reference NIA scenario, DOE analyzed the roll-up scenario. In this scenario, DOE assumed that product efficiencies in the base case that did not meet the standard would roll up to meet the new standard in the compliance year. See section IV.G.2 for a description of the standards case efficiency distribution. For standards-case shipments, DOE used a relative price elasticity that considers the possibility of higher first costs lowering total shipments. The reference NIA scenario also accounted for cross-price elasticity between top-loading and front-loading products to analyze the respective market share of each product class as prices change relative to one another.

The reference NIA scenario used historical data to derive a price scaling index to forecast product costs. The MPCs and MSPs in the GRIM use the default price forecast for all scenarios. See section IV.G.4 for a discussion of DOE's price forecasting methodology.

Markup Scenarios

MSP is equal to MPC times a manufacturer markup. The MSP includes direct manufacturing production costs (*i.e.,* labor, material, and overhead estimated in DOE's MPCs) and all non-production costs (*i.e.,* SG&A, R&D, and interest), along with profit.

To calculate the baseline manufacturer markup, DOE evaluated publicly available financial information for manufacturers of major household appliances whose product offerings include residential clothes washers. DOE also received feedback supporting the 1.22 baseline manufacturer markup during manufacturer interviews. In the base case for all three GRIM markup scenarios, DOE assumed that the products that meet the January 2011 ENERGY STAR criteria earn a moderately higher manufacturer markup than ''baseline'' products that fall below those efficiencies. Additionally, products that meet the CEE Tier 2 and Tier 3 criteria earn an incrementally higher markup than those that meet the 2011 ENERGY STAR criteria.

For the MIA, DOE modeled three standards-case markup scenarios to represent the uncertainty regarding the potential impacts on prices and profitability for manufacturers following the implementation of amended energy conservation standards: (1) A no commoditization markup scenario, (2) a tiered markup scenario, and (3) and a tiered markup with margin pressure scenario. Modifying these markups from the base case to the standards cases yields different sets of impacts on manufacturers' changing industry revenue and cash flow.

The no commoditization scenario assumes that the base-case markup structure (with baseline, ENERGY STAR, and CEE Tier 2 and Tier 3 markups) is maintained in the standards case. This scenario represents the upper bound of industry profitability because manufacturers are able to fully pass through additional costs from amended standards to their customers. In addition to fully passing through higher production costs, manufacturers continue to earn premium markups after standards for products that are no longer differentiated by the ENERGY STAR and CEE programs.

The tiered markup scenario also starts with the three different product markups in the base case (baseline, ENERGY STAR, and CEE Tier 2 and Tier 3 markups). In the standards case, the tiered markup scenario considers the situation in which the breadth of a manufacturer's portfolio of products shrinks and amended standards result in higher-tier products moving to lower tiers. As a result, higher efficiency products that previously commanded the ENERGY STAR and CEE Tier 2 and Tier 3 markups are assigned the ENERGY STAR and baseline markups, respectively. This scenario models a reduction in markups that manufacturers may experience as standards increase and reflects one of the industry's key concerns about product commoditization at higher efficiency levels as efficiency differentiators are eliminated.

DOE also modeled a lower bound profitability scenario. In the tiered markup with margin pressure scenario, the markups of products that exceed the minimum energy conservation standards similarly move to lower efficiency tiers as standards eliminate current efficiency differentiators. In this scenario, the manufacturer markups at the new minimum standard are also lowered. For both top-loading and front-loading clothes washers, manufacturers are able to maintain only the operating profit of the baseline product in absolute dollars. For products at the new minimum energy conservation standards, the higher production costs and the investments required to comply with the amended energy conservation standard do not yield additional operating profit. This scenario models concerns that higher production costs for minimally compliant products could greatly hurt manufacturer profitability because a large segment of the market is greatly impacted by increases in first costs and there would be tremendous pressure to keep entry level products close to today's prices.

3. Discussion of Comments

During the framework public meeting, interested parties commented on the assumptions and results of the manufacturer impacts presented in the framework document. Commenters discussed several topics, including the cumulative regulatory burden on manufacturers, manufacturer tax credits, and manufacturer subgroups. DOE addresses these comments below.

a. Cumulative Regulatory Burden

DOE requested comment in the framework document on other regulations that it should consider in its examination of cumulative regulatory burden. DOE received a number of comments from interested parties.

AHAM stated that the International Association of Plumbing and Manufacturing Officials (IAPMO) recently released a draft version of ''The Green Plumbing and Mechanical Model Supplement'' for comment. The draft suggests that local municipalities may adopt a requirement for a WF of 5.0 or less. AHAM commented that if this proposal moves forward, it will introduce substantial additional regulatory burden for clothes washer manufacturers, as these requirements are substantially lower than 2011 ENERGY STAR levels. (AHAM, No. 15 at p. 5) Whirlpool stated that the proliferation of green building standards from entities such as *the* U.S. Green Building Council (USGBC), EPA, National Association of Home Builders (NAHB), and now IAPMO, creates an additional burden on manufacturers. (Whirlpool, No. 22 at p. 7) Conversely, ASAP argued that the IAPMO specifications referred to by AHAM are voluntary codes that local communities can consider. (ASAP, Public Meeting Transcript, No. 7 at p. 96) ASAP also commented that misapplying voluntary criteria in an attempt to write local standards is a hazard regardless of efficiency standards. (ASAP, Public Meeting Transcript, No. 7 at p. 96)

AHAM and GE stated that CEE Tiers continue to be raised in response to DOE standards levels, and local municipalities may require a CEE Tier rating for various incentives. In general, CEE Tiers are some percentage of a DOE standard and do not have strong data to support the levels. AHAM and GE commented that CEE Tiers may push the technology beyond practical performance and/or price points. (AHAM, No. 16 at p. 5; AHAM, Public Meeting Transcript, No. 7 at p. 95; GE, No. 20 at p. 1) ASAP commented that DOE is concerned with outside regulatory changes, and the CEE Tiers Program is not a regulatory program. (ASAP, Public Meeting Transcript, No. 7 at p. 96)

For the cumulative regulatory burden, DOE attempts to quantify or describe the impacts of other Federal regulations that have a compliance date within approximately three years of the compliance date of this rulemaking. While DOE describes voluntary programs that influence the efficiency of clothes washers in the cumulative burden and acknowledges that these programs can impact the product offerings of residential clothes washer manufacturers, DOE does not quantify the costs to comply with future voluntary programs because they are outside the scope of the cumulative regulatory burden. DOE notes that a WF of 5.0 or less considered by IAPMO corresponds to the front-loading standard size standards in the direct final rule and in the Joint Petition for 2015. DOE also notes that 42 U.S.C. 6297 describes EPCA's preemption of state and local regulation of appliance efficiency, including such requirements in State or local building codes.

ALS commented on the cumulative regulatory burden of the Restriction of Hazardous Substances (RoHS) Directive already existing in Europe and similar legislation that has been proposed in some states in the United States. (ALS, No. 13 at p. 12) Whirlpool stated that DOE should consider the increasing regulation of materials and RoHS proposals in its analysis of residential clothes washers. (Whirlpool, No. 22 at p. 7) AHAM commented that RoHS, and other hazardous substance issues are substantial regulatory burdens that are accumulating on manufacturers. (AHAM, Public Meeting Transcript, No. 7 at p. 165)

Most manufacturers of residential clothes washers that sell products in the United States also sell products in the European Union and must comply with the RoHS directive for those products sold in the European Union. While the potential restrictions of other hazardous substances and the potential for states to implement similar bans are also concerns for manufacturers, there is currently no corresponding Federal ban on many of the substances found in the RoHS directive. Therefore, DOE does not account for RoHS compliance costs in its calculation of product conversion costs.

AHAM stated that EPA is requiring the transition away from hydrochlorofluorocarbons (HCFCs), a shift to which the home appliance industry must devote resources. (AHAM, Public Meeting Transcript, No. 7 at p. 165) In response, DOE notes that residential clothes washers do not use HCFCs, and none of the design options analyzed by DOE would require changes to clothes washers due to the EPA phase-out.

Several manufacturers commented on the burden imposed by UL standards. ALS stated that a cumulative regulatory burden is imposed by the revision of UL Standard 2158 for clothes dryer safety, which requires fire containment test compliance by March 20, 2013. (ALS, No. 13 at p. 12) Whirlpool is concerned with the cumulative regulatory burden of new UL standards on entrapment for both clothes washers and dishwashers, new UL fire containment standards for clothes dryers, and a number of other safety standards for both products and components that are propagated by UL. (Whirlpool, No. 22 at p. 7) AHAM stated that there are several UL safety and functional standards that draw resources from manufacturers. BSH stated that UL 2157 and UL 2158 have been revised and present a regulatory burden to laundry appliance manufacturers. (BSH, No. 11 at p. 5) Miele stated that UL 2157 may require redesign of door lock mechanisms to prevent child entrapment, and that a similar effort is underway for dishwashers. UL 2158 was just revised, which, according to Miele will also cause a major redesign for fire containment in clothes dryer manufacturers. (Miele, Public Meeting Transcript, No. 7 at p. 165)

In the clothes dryer rulemaking, DOE accounted for the conversion costs for manufacturers to comply with the revisions to UL 2158 as mentioned in the comments from interested parties. DOE notes that the UL 2157 and 2158 are not Federal regulations. In contrast to the RoHS Directive requirements discussed previously, UL certification is a *de facto* requirement for selling products in the U.S. because many local building codes require all installed products to meet safety regulations. DOE has included the UL certification costs for both UL 2157 and UL 2158 as a sensitivity scenario in the GRIM, but does not include the UL conversion costs in the main MIA results. Refer to chapter 12 of the direct final rule TSD for more information about how DOE calculated the UL conversion costs.

AHAM, ALS, GE, and Whirlpool stated that the existing DOE rulemakings for commercial clothes washer and residential clothes dryer minimum standards represent a cumulative regulatory burden. Some of these commenters added that the DOE refrigerator and room air conditioner rulemaking result in additional regulatory burdens. (AHAM, No. 16 at p. 6; AHAM, Public Meeting Transcript, No. 7 at p. 96; ALS, No. 13 at p. 12; GE, No. 20 at p. 1; Whirlpool, No. 22 at p. 7)

DOE agrees that these rulemakings are a part of the cumulative regulatory burden on manufacturers. DOE has attempted to quantify the impact of the other DOE energy conservation standards that have a compliance date within approximately three years of the compliance date of this rulemaking in chapter 12 of the direct final rule TSD.

AHAM added that cumulative regulatory burden is made even more demanding by the current economic conditions, and this rulemaking should explicitly consider cumulative regulatory impact in the economic justification analysis. (AHAM, Public Meeting Transcript, No. 7 at p. 96) PG&E stated that its understanding is that DOE compares the standards-case impacts to the base-case impacts, so that events such as the recession and other regulatory burdens that are independent of this rulemaking would not be considered. (PG&E, Public Meeting Transcript, No. 7 at p. 167) ASAP questioned how DOE intends to deal with the effects of the economic downturn and the potential recovery on shipment forecasts, and whether there is some sort of consistent approach DOE is considering with its other rulemakings. (ASAP, Public Meeting Transcript, No. 7 at p. 101)

DOE considers the cumulative regulatory burden on manufacturers as part of its statutory criteria to justify any energy conservation standard—the economic impact on manufacturers and consumers (42 U.S.C. 6295(o)(2)(B)(i)). DOE considers the cumulative regulatory burden in the qualitative part of its MIA analysis, though it attempts to quantify the cumulative regulatory burden whenever possible. In the MIA, DOE also modeled the impacts of amended energy conservation standards on residential clothes washer manufacturers from base year to the end of the analysis period (2011–2044). DOE used the most current information that is publicly available in many of its estimates and analyses, inputs that take the current economic downturn into consideration. For example, DOE used financial parameters like standard R&D to model the cash-flow impacts on the industry. To calculate the estimates of the financial parameters used in the GRIMs, DOE examined the latest six years of SEC 10–K data. These estimates were meant to reflect the parameters that are representative of each industry over the long-term and are not specifically attributable to current economic conditions.

As in other rulemakings, DOE used AHAM data for historical shipments. That data reflects the economic downturn for residential products including clothes washers. DOE also considers standards-case impacts with respect to the base case as part of the NIA (see section IV.G.2).

b. Manufacturer Tax Credits

DOE requested input on any ''market pull'' programs, such as manufacturer tax credits, that promote the adoption of more efficient residential clothes washers.

ASAP stated that DOE should find an effective way to address the effects of manufacturer tax incentives on conversion costs and the production credits available under current law for the production of high efficiency machines. (ASAP, Public Meeting Transcript, No. 7 at p. 83) The Joint Comment stated that DOE must fully account for the effects of Federal production tax credits in the MIA. Federal production tax credits for manufacturers of high efficiency appliances, including residential clothes washers, were first enacted in 2005 and then extended and expanded in 2008. The Joint Comment further stated that production tax credits provided manufacturers with a substantial incentive to continue to increase production of efficient front-loaders and top-loaders through 2010. According to the Joint Comment, these tax credits should substantially off-set the conversion capital requirements and product conversion expenses of meeting higher standards that are key inputs to the MIA. (Joint Comment, No. 15 at p. 7) Earthjustice commented that it would seem inconsistent to consider the tax credits for purposes of the MIA, and not to also consider that the tax credits may have an impact on the price of the product. (Earthjustice, Public Meeting Transcript, No. 7 at p. 83) SCE questioned whether DOE captures any positive manufacturer impacts due to the standards rulemaking. (SCE, Public Meeting Transcript, No. 7 at p. 166)

DOE considers all relevant manufacturer impacts, both positive and negative. For example, DOE's analysis includes the effects of any manufacturer production tax credits that may benefit certain manufacturers. ASAP and the Joint Comment above refer to tax credits that applied to residential clothes washers. However, these tax credits expired in 2010. Because 2011 is the base year to which industry cash flows are discounted on this rulemaking, any Federal production tax credits received by the industry fall outside of the analysis period and are not considered in the INPV analysis. While there are tax credits in proposed legislation, DOE is not aware of any existing Federal production tax credits that would substantially offset the required conversion costs for manufacturers. Federal production tax credits and other market pull programs such as ENERGY STAR and the CEE Tiers have helped spur the development and acceptance of more efficient products which DOE has accounted for in the market distribution of current products in the base case. However, such tax credits and other market pull programs would not substantially defray the capital conversion costs required if all products were required to meet the given efficiency.

c. Manufacturer Subgroups

DOE requested comment on appropriate manufacturer subgroups, if any, that DOE should consider in its manufacturer subgroup analysis for residential clothes washers. ALS suggested that low-volume manufacturers with less than 5 percent market share, including itself, be considered a manufacturer subgroup. (ALS, No. 13 at p. 12) ALS also stated that it is a highly leveraged small company that doesn't have the resources that the three major residential clothes washer manufacturers do. (ALS, Public Meeting Transcript, No. 7 at p. 165) AHAM stated that smaller niche manufacturers should be considered as a manufacturer subgroup. AHAM commented that these manufacturers often have less access to the newer technologies, and, in this economic climate, have fewer resources available for research and development of products. (AHAM, Public Meeting Transcript, No. 7 at p. 163) Whirlpool stated that it is unaware of any manufacturer subgroups that would be impacted differently from other manufacturers under this rulemaking. (Whirlpool, No. 22 at p. 10)

In the commercial clothes washers (CCW) final rule, DOE described the disproportionate impacts on the Low Volume Manufacturer (LVM) in the NOPR and TSD. DOE considered this manufacturer to be low-volume because its annual shipments in the combined residential and CCW market were significantly lower than those of its larger competitors. However, unlike its larger rivals, most of the LVM's unit shipments were in the CCW market, where the LVM had significant market share. Historically, this company derived 22 percent of its total revenue from the sale of front- and top-loading clothes washers and 87 percent of that revenue was from the commercial market. As a result, DOE believed that the LVM could be affected disproportionately by any rulemaking concerning CCWs compared to its competitors, for whom CCWs represent less than 2 percent of total clothes washer sales. 75 FR 1122, 1137 (Jan. 8, 2010). However, DOE does not believe that a Low Volume subgroup is warranted for residential clothes washers because the CCW LVM has a small presence in the residential clothes washer market and residential clothes washers represent a small portion of overall clothes washer sales and a smaller portion of total revenue. DOE also notes that ALS, AHAM, and many other manufacturers signed the Joint Petition that included residential clothes washer standards identical to those in today's direct final rule. DOE also describes the potential impacts on the small business manufacturer it identified in section VI.B but does not report impacts on any other subgroups of manufacturers.

d. Miscellaneous

ASAP asked whether and how overseas manufacturers are engaged in the manufacturer interview process. (ASAP, Public Meeting Transcript, No. 7 at p. 108)

DOE invited as many domestic and international clothes washer manufacturers that sell products in the U.S. as it could identify to participate in the rulemaking process. DOE considered inputs from and interviewed the two international manufacturers that responded to its requests for participation. DOE notes that one of these manufacturers has domestic production.

4. Manufacturer Interviews

DOE interviewed manufacturers representing more than 80 percent of residential clothes washer sales. These interviews were in addition to those DOE conducted as part of the engineering analysis. DOE used these interviews to tailor the GRIM to incorporate unique financial characteristics of the industry. All interviews provided information that DOE used to evaluate the impacts of potential amended energy conservation standards on manufacturer cash flows, manufacturing capacities, and employment levels. See appendix 12–A of the direct final rule TSD for additional information on the MIA interviews. The following sections describe the most significant issues identified by manufacturers.

a. Potentially Large Conversion Costs

Manufacturers indicated that they were greatly concerned about the potential for this rulemaking to require significant product and capital conversion costs. Introducing new residential clothes washer platforms involves very large upfront costs. These capital and product development costs can be justified because a basic platform typically undergoes incremental changes over a number design cycles and the initial investment can be at least partially spread over all these shipments. Many of the existing residential clothes washer platforms have some designs options available that would necessitate only these incremental types of changes. Substantially higher efficiencies, however, could potentially necessitate a drum or cabinet capacity change. In this case, rather than requiring alteration of the current platform, the required changes would likely require design of a completely new platform. A new platform would require replacing most production equipment at a very large capital cost. Manufacturers also indicated that these initial costs for a new basic platform could result in a substantial shift in employment. Some manufacturers were also concerned that devoting resources to efficiency improvements could hurt their products in the market because these efforts could come at the expense of other features.

b. Product Classes

Manufacturers were divided on the need to retain top-loading and front-loading standard-size product classes. In general, manufacturers who produce top-loading clothes washers favored retaining the two distinct product classes. Manufacturers who produce only front-loading clothes washers were less concerned with maintaining the method of access as a product class distinction.

While all manufacturers agreed front-loading clothes washers are an important product offering, many manufacturers also stated that top-loading clothes washers are an important option for consumers because they have lower cycle times, lower price points, lower installation costs because they do not require a pedestal, are easier to load, are easier to add garments mid-cycle, and have less vibration. Some manufacturers in favor of maintaining the separate product classes also stated that eliminating top-loading clothes washers would harm lower-income customers who typically purchase baseline clothes washers. In addition, because front-loading clothes washers are mature in the marketplace, consumers are aware of the benefits of top-loading clothes washers, high efficiency top-loading products, and front-loading clothes washers and have the ability to choose higher efficiency products in either configuration.

c. Wash Performance

Manufacturers were concerned that efficiency gains over time have limited the potential to improve efficiency without negatively impacting wash performance (and the consumer). Many manufacturers were concerned that a test procedure that did not take a minimum wash performance into consideration, coupled with a more stringent energy conservation standard, could force manufacturers to limit water to a level that would harm consumers. For example, over-sudsing could be more commonplace. Also, water levels could be reduced to the point where cold water would no longer sufficiently clean clothes. Either one of these issues would result in lost energy savings as consumers either rewashed clothes or no longer selected cold water wash cycles. Consequently, many manufacturers supported adding a performance metric to the test procedure to ensure that consumers would genuinely benefit from improved efficiency.

d. Tub Capacity Measurement

Many manufacturers mentioned that different companies use inconsistent approaches in measuring tub capacity. While manufacturers offered slightly different suggestions for how to measure capacity, most were supportive of eliminating the ambiguity. Manufacturers hoped this issue would be resolved before the implementation of these amended energy conservation standards because the modified energy factor and water factor calculations are dependent on measured capacity.

e. ENERGY STAR

Manufacturers stated that the ENERGY STAR program is also a part of their overall energy strategy. To be competitive, many manufacturers must take ENERGY STAR levels into consideration when designing new clothes washers. One manufacturer mentioned that the costs associated with designing new products to meet ENERGY STAR levels were not reflected in DOE's incremental cost tables.

Another manufacturer mentioned that ENERGY STAR is an important purchasing decision, especially in the front-loading clothes washer market. The manufacturer expressed concern that standards that are too aggressive could put the future of the ENERGY STAR program for residential clothes washers in jeopardy. In turn, that could impact local rebates that enable manufacturers to offer products that meet the minimum efficiency standards.

J. Employment Impact Analysis

DOE considers employment impacts in the domestic economy as one factor in selecting a proposed standard. Employment impacts include direct and indirect impacts. Direct employment impacts are any changes in the number of employees of manufacturers of the products subject to standards, their suppliers, and related service firms. The MIA addresses those impacts. Indirect employment impacts are changes in national employment that occur due to the shift in expenditures and capital investment caused by the purchase and operation of more efficient appliances. Indirect employment impacts from standards consist of the jobs created or eliminated in the national economy, other than in the manufacturing sector being regulated, due to: (1) Reduced spending by end users on energy; (2) reduced spending on new energy supply by the utility industry; (3) increased consumer spending on the purchase of new products; and (4) the effects of those three factors throughout the economy.

One method for assessing the possible effects on the demand for labor of such shifts in economic activity is to compare sector employment statistics developed by the Labor Department's Bureau of Labor Statistics (BLS). BLS regularly publishes its estimates of the number of jobs per million dollars of economic activity in different sectors of the economy, as well as the jobs created elsewhere in the economy by this same economic activity. Data from BLS indicate that expenditures in the utility sector generally create fewer jobs (both directly and indirectly) than expenditures in other sectors of the economy.[35] There are many reasons for these differences, including wage differences and the fact that the utility sector is more capital-intensive and less labor-intensive than other sectors. Energy conservation standards have the effect of reducing consumer utility bills. Because reduced consumer expenditures for energy likely lead to increased expenditures in other sectors of the economy, the general effect of efficiency standards is to shift economic activity from a less labor-intensive sector (*i.e.,* the utility sector) to more labor-intensive sectors (*e.g.,* the retail and service sectors). Thus, based on the BLS data alone, DOE believes net national employment may increase because of shifts in economic activity resulting from amended standards for clothes washers.

For the standard levels considered in today's direct final rule, DOE estimated indirect national employment impacts using an input/output model of the U.S. economy called Impact of Sector Energy Technologies version 3.1.1 (ImSET). ImSET is a special-purpose version of the ''U.S. Benchmark National Input-Output'' (I–O) model, which was designed to estimate the national employment and income effects of energy-saving technologies. The ImSET software includes a computer-based I–O model having structural coefficients that characterize economic flows among the 187 sectors. ImSET's national economic I–O structure is based on a 2002 U.S. benchmark table, specially aggregated to the 187 sectors most relevant to industrial, commercial, and residential building energy use. DOE notes that ImSET is not a general equilibrium forecasting model. Given the relatively small change to expenditures due to energy conservation standards and the resulting small changes to employment, however, DOE believes that the size of any forecast error caused by using ImSET will be small.

For more details on the employment impact analysis, see chapter 13 of the direct final rule TSD.

K. Utility Impact Analysis

The utility impact analysis estimates several important effects on the utility industry of the adoption of new or amended standards. For this analysis, DOE used the NEMS–BT model to generate forecasts of electricity consumption, electricity generation by plant type, and electric generating capacity by plant type, that would result from each TSL. DOE obtained the energy savings inputs associated with efficiency improvements to considered products from the NIA. DOE conducts the utility impact analysis as a scenario that departs from the latest *AEO* Reference case. In the analysis for today's rule, the estimated impacts of standards are the differences between values forecasted by NEMS–BT and the values in the *AEO2010* Reference case.

As part of the utility impact analysis, DOE used NEMS–BT to assess the impacts on electricity prices of the reduced need for new electric power plants and infrastructure projected to result from the considered standards. In NEMS–BT, changes in power generation infrastructure affect utility revenue requirements, which in turn affect electricity prices. DOE estimated the change in electricity prices projected to result over time from each TSL. For further discussion, see section IV.G.5. For more details on the utility impact analysis, see chapter 14 of the direct final rule TSD.

In the framework document, DOE requested comment on the utility impact analysis, and in response received several comments from efficiency advocates and utilities. The California Utilities recommended that DOE evaluate how the standard will affect water and wastewater utilities, including their water infrastructure requirements. (California Utilities, No. 19 at p. 6) The Joint Comment stated that a new standard has the potential to have a substantial impact on the capital and operating cost profiles of water and wastewater utilities over the thirty-year period of analysis. (Joint Comment, No. 15 at p. 8)

DOE acknowledges that clothes washer standards could affect water and wastewater utilities. However, to analyze water and wastewater utility impacts, an analytical tool comparable to NEMS would be needed to account properly for the nationwide effects of standards on water and wastewater delivery and treatment. At this time, DOE does not have such a tool or access to any other means to quantify the water and wastewater utility impacts from potential clothes washer standards.

L. Emissions Analysis

In the emissions analysis, DOE estimated the reduction in power sector emissions of CO_2, NO_X, and Hg from amended energy conservation standards for clothes washers. DOE used the NEMS–BT computer model, which is run similarly to the *AEO* NEMS, except that clothes washer energy use is reduced by the amount of energy saved (by fuel type) due to each TSL. The inputs of national energy savings come from the NIA spreadsheet model, while the output is the forecasted physical emissions. The net benefit of each TSL is the difference between the forecasted emissions estimated by NEMS–BT at each TSL and the *AEO2010* Reference Case. NEMS–BT tracks CO_2 emissions using a detailed module that provides results with broad coverage of all sectors and inclusion of interactive effects. For today's rule, DOE used the version of NEMS–BT based on *AEO2010,* which incorporated projected effects of all emissions regulations promulgated as of Jan. 31, 2010.

[35] See Bureau of Economic Analysis, *Regional Multipliers: A User Handbook for the Regional Input-Output Modeling System (RIMS II).* Washington, DC. U.S. Department of Commerce, 1992.

SO_2 emissions from affected electric generating units (EGUs) are subject to nationwide and regional emissions cap and trading programs, and DOE has determined that these programs create uncertainty about the impact of energy conservation standards on SO_2 emissions. Title IV of the Clean Air Act sets an annual emissions cap on SO_2 for affected EGUs in the 48 contiguous States and the District of Columbia (DC). SO_2 emissions from 28 eastern States and DC are also limited under the Clean Air Interstate Rule (CAIR, 70 FR 25162 (May 12, 2005)), which created an allowance-based trading program that would gradually replace the Title IV program in those States and DC. Although CAIR was remanded to EPA by the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit), see *North Carolina* v. *EPA,* 550 F.3d 1176 (D.C. Cir. 2008), it remained in effect temporarily, consistent with the D.C. Circuit's earlier opinion in *North Carolina* v. *EPA,* 531 F.3d 896 (D.C. Cir. 2008). On July 6, 2010, EPA issued the Transport Rule proposal, a replacement for CAIR. 75 FR 45210 (Aug. 2, 2010). On July 6, 2011 EPA issued a replacement for CAIR, the Cross-State Air Pollution Rule. 76 FR 48208 (August 8, 2011). (See *http://www.epa.gov/crossstaterule/*). On December 30, 2011, however, the D.C. Circuit stayed the new rules while a panel of judges reviews them, and told EPA to continue enforcing CAIR (see *EME Homer City Generation* v. *EPA,* No. 11–1302, Order at *2 (D.C. Cir. Dec. 30, 2011)). The *AEO2010* NEMS–BT used for today's direct final rule assumes the implementation of CAIR.

The attainment of emissions caps typically is flexible among EGUs and is enforced through the use of emissions allowances and tradable permits. Under existing EPA regulations, any excess SO_2 emissions allowances resulting from the lower electricity demand caused by the imposition of an efficiency standard could be used to permit offsetting increases in SO_2 emissions by any regulated EGU. However, if the standard resulted in a permanent increase in the quantity of unused emissions allowances, there would be an overall reduction in SO_2 emissions from the standards. While there remains some uncertainty about the ultimate effects of efficiency standards on SO_2 emissions covered by the existing cap-and-trade system, the NEMS–BT modeling system that DOE uses to forecast emissions reductions currently indicates that no physical reductions in power sector emissions would occur for SO_2.

As discussed above, the *AEO2010* NEMS–BT used for today's NOPR assumes the implementation of CAIR, which established a cap on NO_X emissions in 28 eastern States and the District of Columbia. With CAIR in effect, the energy conservation standards for clothes washers are expected to have little or no physical effect on NO_X emissions in those States covered by CAIR, for the same reasons that they may have little effect on SO_2 emissions. However, the standards would be expected to reduce NO_X emissions in the 22 States not affected by CAIR. For these 22 States, DOE used the NEMS–BT to estimate NO_X emissions reductions from the standards considered in today's direct final rule.

On December 21, 2011, EPA announced national emissions standards for hazardous air pollutants (NESHAPs) for mercury and certain other pollutants emitted from coal and oil-fired EGUs. 76 FR 24976. The NESHAPs do not include emissions caps and, as such, DOE's energy conservation standards would likely reduce Hg emissions. For the emissions analysis for this rulemaking, DOE estimated mercury emissions reductions using NEMS–BT based on *AEO2010,* which does not incorporate the NESHAPs. DOE expects that future versions of the NEMS–BT model will reflect the implementation of the NESHAPs.

M. Monetizing Carbon Dioxide and Other Emissions Impacts

As part of the development of this direct final rule, DOE considered the estimated monetary benefits likely to result from the reduced emissions of CO_2 and NO_X that are expected to result from each of the considered TSLs. In order to make this calculation similar to the calculation of the NPV of consumer benefit, DOE considered the reduced emissions expected to result over the lifetime of products shipped in the forecast period for each TSL. This section summarizes the basis for the monetary values used for each of these emissions and presents the benefits estimates considered.

For today's direct final rule, DOE is relying on a set of values for the social cost of carbon (SCC) that was developed by an interagency process. A summary of the basis for these values is provided below, and a more detailed description of the methodologies used is provided in appendix 15–A of the direct final rule TSD.

1. Social Cost of Carbon

Under Executive Order 12866, agencies must, to the extent permitted by law, ''assess both the costs and the benefits of the intended regulation and, recognizing that some costs and benefits are difficult to quantify, propose or adopt a regulation only upon a reasoned determination that the benefits of the intended regulation justify its costs.'' The purpose of the SCC estimates presented here is to allow agencies to incorporate the monetized social benefits of reducing CO_2 emissions into cost-benefit analyses of regulatory actions that have small, or ''marginal,'' impacts on cumulative global emissions. The estimates are presented with an acknowledgement of the many uncertainties involved and with a clear understanding that they should be updated over time to reflect increasing knowledge of the science and economics of climate impacts.

As part of the interagency process that developed these SCC estimates, technical experts from numerous agencies met on a regular basis to consider public comments, explore the technical literature in relevant fields, and discuss key model inputs and assumptions. The main objective of this process was to develop a range of SCC values using a defensible set of input assumptions grounded in the existing scientific and economic literatures. In this way, key uncertainties and model differences transparently and consistently inform the range of SCC estimates used in the rulemaking process.

a. Monetizing Carbon Dioxide Emissions

The SCC is an estimate of the monetized damages associated with an incremental increase in carbon emissions in a given year. It is intended to include (but is not limited to) changes in net agricultural productivity, human health, property damages from increased flood risk, and the value of ecosystem services. Estimates of the SCC are provided in dollars per metric ton of carbon dioxide.

When attempting to assess the incremental economic impacts of carbon dioxide emissions, the analyst faces a number of serious challenges. A recent report from the National Research Council [36] points out that any assessment will suffer from uncertainty, speculation, and lack of information about (1) future emissions of greenhouse gases, (2) the effects of past and future emissions on the climate system, (3) the impact of changes in climate on the physical and biological environment,

[36] National Research Council. *Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use.* National Academies Press: Washington, DC. 2009.

and (4) the translation of these environmental impacts into economic damages. As a result, any effort to quantify and monetize the harms associated with climate change will raise serious questions of science, economics, and ethics and should be viewed as provisional.

Despite the serious limits of both quantification and monetization, SCC estimates can be useful in estimating the social benefits of reducing carbon dioxide emissions. Consistent with the directive quoted above, the purpose of the SCC estimates presented here is to make it possible for agencies to incorporate the social benefits from reducing carbon dioxide emissions into cost-benefit analyses of regulatory actions that have small, or ''marginal,'' impacts on cumulative global emissions. Most Federal regulatory actions can be expected to have marginal impacts on global emissions.

For such policies, the agency can estimate the benefits from reduced (or costs from increased) emissions in any future year by multiplying the change in emissions in that year by the SCC value appropriate for that year. The net present value of the benefits can then be calculated by multiplying each of these future benefits by an appropriate discount factor and summing across all affected years. This approach assumes that the marginal damages from increased emissions are constant for small departures from the baseline emissions path, an approximation that is reasonable for policies that have effects on emissions that are small relative to cumulative global carbon dioxide emissions. For policies that have a large (non-marginal) impact on global cumulative emissions, there is a separate question of whether the SCC is an appropriate tool for calculating the benefits of reduced emissions. This concern is not applicable to this notice, and DOE does not attempt to answer that question here.

At the time of the preparation of this notice, the most recent interagency estimates of the potential global benefits resulting from reduced CO_2 emissions in 2010, expressed in 2010$, were $4.9, $22.3, $36.5, and $67.6 per metric ton avoided. For emission reductions that occur in later years, these values grow in real terms over time. Additionally, the interagency group determined that a range of values from 7 percent to 23 percent should be used to adjust the global SCC to calculate domestic effects,[37] although preference is given to consideration of the global benefits of reducing CO_2 emissions.

It is important to emphasize that the interagency process is committed to updating these estimates as the science and economic understanding of climate change and its impacts on society improves over time. Specifically, the interagency group has set a preliminary goal of revisiting the SCC values within 2 years or at such time as substantially updated models become available, and to continue to support research in this area. In the meantime, the interagency group will continue to explore the issues raised by this analysis and consider public comments as part of the ongoing interagency process.

b. Social Cost of Carbon Values Used in Past Regulatory Analyses

To date, economic analyses for Federal regulations have used a wide range of values to estimate the benefits associated with reducing carbon dioxide emissions. In the final model year 2011 CAFE rule, the U.S. Department of Transportation (DOT) used both a ''domestic'' SCC value of $2 per ton of CO_2 and a ''global'' SCC value of $33 per ton of CO_2 for 2007 emission reductions (in 2007$), increasing both values at 2.4 percent per year.[38] DOT also included a sensitivity analysis at $80 per ton of CO_2. See *Average Fuel Economy Standards Passenger Cars and Light Trucks Model Year 2011,* 74 FR 14196 (March 30, 2009) (Final Rule); Final Environmental Impact Statement Corporate Average Fuel Economy Standards, Passenger Cars and Light Trucks, Model Years 2011–2015 at 3–90 (Oct. 2008) (Available at: *www.nhtsa.gov/fuel-economy*). A domestic SCC value is meant to reflect the value of damages in the United States resulting from a unit change in carbon dioxide emissions, while a global SCC value is meant to reflect the value of damages worldwide.

A 2008 regulation proposed by DOT assumed a domestic SCC value of $7 per ton of CO_2 (in 2006$) for 2011 emission reductions (with a range of $0 − $14 for sensitivity analysis), also increasing at 2.4 percent per year. See *Average Fuel Economy Standards, Passenger Cars and Light Trucks, Model Years 2011–2015,* 73 FR 24352 (May 2, 2008) (Proposed Rule); Draft Environmental Impact Statement Corporate Average Fuel Economy Standards, Passenger Cars and Light Trucks, Model Years 2011–2015 at 3–58 (June 2008) (Available at: *http://www.nhtsa.gov/fuel-economy*). A regulation for packaged terminal air conditioners and packaged terminal heat pumps finalized by DOE in October of 2008 used a domestic SCC range of $0 to $20 per ton CO_2 for 2007 emission reductions (in 2007$), 73 FR 58772, 58814 (Oct. 7, 2008). In addition, EPA's 2008 Advance Notice of Proposed Rulemaking for Greenhouse Gases identified what it described as ''very preliminary'' SCC estimates subject to revision. See *Regulating Greenhouse Gas Emissions Under the Clean Air Act,* 73 FR 44354 (July 30, 2008). EPA's global mean values were $68 and $40 per ton CO_2 for discount rates of approximately 2 percent and 3 percent, respectively (in 2006$ for 2007 emissions).

In 2009, an interagency process was initiated to offer a preliminary assessment of how best to quantify the benefits from reducing carbon dioxide emissions. To ensure consistency in how benefits are evaluated across agencies, the Administration sought to develop a transparent and defensible method, specifically designed for the rulemaking process, to quantify avoided climate change damages from reduced CO_2 emissions. The interagency group did not undertake any original analysis. Instead, it combined SCC estimates from the existing literature to use as interim values until a more comprehensive analysis could be conducted. The outcome of the preliminary assessment by the interagency group was a set of five interim values: Global SCC estimates for 2007 (in 2006 dollars) of $55, $33, $19, $10, and $5 per ton of CO_2. These interim values represent the first sustained interagency effort within the U.S. government to develop an SCC for use in regulatory analysis. The results of this preliminary effort were presented in several proposed and final rules and were offered for public comment in connection with proposed rules, including the joint EPA–DOT fuel economy and CO_2 tailpipe emission proposed rules.

c. Current Approach and Key Assumptions

Since the release of the interim values, the interagency group reconvened on a regular basis to generate improved SCC estimates, which were used in this direct final rule. Specifically, the group considered public comments and further explored the technical literature in relevant fields. The interagency group relied on three integrated assessment models (IAMs) commonly used to estimate the SCC: The FUND, DICE, and PAGE

[37] It is recognized that this calculation for domestic values is approximate, provisional, and highly speculative. There is no a priori reason why domestic benefits should be a constant fraction of net global damages over time.

[38] Throughout this section, references to tons of CO_2 refer to metric tons.

models.[39] These models are frequently cited in the peer-reviewed literature and were used in the last assessment of the Intergovernmental Panel on Climate Change. Each model was given equal weight in the SCC values that were developed.

Each model takes a slightly different approach to model how changes in emissions result in changes in economic damages. A key objective of the interagency process was to enable a consistent exploration of the three models while respecting the different approaches to quantifying damages taken by the key modelers in the field. An extensive review of the literature was conducted to select three sets of input parameters for these models: Climate sensitivity, socio-economic and emissions trajectories, and discount rates. A probability distribution for climate sensitivity was specified as an input into all three models. In addition, the interagency group used a range of scenarios for the socio-economic parameters and a range of values for the discount rate. All other model features were left unchanged, relying on the model developers' best estimates and judgments.

The interagency group selected four SCC values for use in regulatory analyses. Three values are based on the average SCC from three integrated assessment models, at discount rates of 2.5, 3, and 5 percent. The fourth value, which represents the 95th percentile SCC estimate across all three models at a 3-percent discount rate, is included to represent higher-than-expected impacts from temperature change further out in the tails of the SCC distribution.

TABLE IV–21—SOCIAL COST OF CO_2, 2010–2050
[In 2007 dollars per metric ton]

	Discount rate			
	5% Avg	3% Avg	2.5% Avg	3% 95th
2010	4.7	21.4	35.1	64.9
2015	5.7	23.8	38.4	72.8
2020	6.8	26.3	41.7	80.7
2025	8.2	29.6	45.9	90.4
2030	9.7	32.8	50.0	100.0
2035	11.2	36.0	54.2	109.7
2040	12.7	39.2	58.4	119.3
2045	14.2	42.1	61.7	127.8
2050	15.7	44.9	65.0	136.2

It is important to recognize that a number of key uncertainties remain, and that current SCC estimates should be treated as provisional and revisable since they will evolve with improved scientific and economic understanding. The interagency group also recognizes that the existing models are imperfect and incomplete. The National Research Council report mentioned above points out that there is tension between the goal of producing quantified estimates of the economic damages from an incremental ton of carbon and the limits of existing efforts to model these effects. There are a number of concerns and problems that should be addressed by the research community, including research programs housed in many of the agencies participating in the interagency process to estimate the SCC.

DOE recognizes the uncertainties embedded in the estimates of the SCC used for cost-benefit analyses. As such, DOE and others in the U.S. Government intend to periodically review and reconsider those estimates to reflect increasing knowledge of the science and economics of climate impacts, as well as improvements in modeling. In this context, statements recognizing the limitations of the analysis and calling for further research take on exceptional significance.

In summary, in considering the potential global benefits resulting from reduced CO_2 emissions, DOE used the most recent values identified by the interagency process, adjusted to 2010$ using the GDP price deflator. For each of the four cases specified, the values used for emissions in 2010 were $4.9, $22.3, $36.5, and $67.6 per metric ton avoided (values expressed in 2010$).[40] To monetize the CO_2 emissions reductions expected to result from amended standards for clothes washers, DOE used the values identified in Table A1 of the ''Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866,'' which is reprinted in appendix 16–A of the direct final rule TSD, appropriately adjusted to 2010$. To calculate a present value of the stream of monetary values, DOE discounted the values in each of the four cases using the specific discount rate that had been used to obtain the SCC values in each case.

Commenting on the framework document, Whirlpool stated that CO_2 emissions should not be monetized because the market value cannot be readily determined, the impact is negligible, and it is already included in energy savings. (Whirlpool, No. 22 at p. 6) DOE acknowledges that the market value of future CO_2 emissions reductions is uncertain, and for this reason it uses a wide range of potential values, as described above. The impact of revised standards clothes washers on future CO_2 emissions, described in section V.B.6 of this notice, is not negligible. In addition, the value of CO_2 emissions reductions is not included in energy cost savings because the energy prices that DOE used to calculate those savings do not include any taxes or other charges to account for the CO_2 emissions associated with the use of electricity or natural gas by residential clothes washers.

2. Valuation of Other Emissions Reductions

DOE investigated the potential monetary benefit of reduced NO_X emissions from the TSLs it considered. As noted above, amended energy conservation standards would reduce NO_X emissions in those 22 States that are not affected by the CAIR, in addition to the reduction in site NO_X emissions nationwide. DOE estimated the monetized value of NO_X emissions

[39] The models are described in appendix 15–A of the direct final rule TSD.

[40] Table A1 presents SCC values through 2050. For DOE's calculation, it derived values after 2050 using the 3-percent per year escalation rate used by the interagency group.

reductions resulting from each of the TSLs considered for today's direct final rule based on environmental damage estimates from the literature. Available estimates suggest a very wide range of monetary values, ranging from $370 per ton to $3,800 per ton of NO_X from stationary sources, measured in 2001$ (equivalent to a range of $450 to $4,623 per ton in 2010$).[41] In accordance with OMB guidance, DOE conducted two calculations of the monetary benefits derived using each of the economic values used for NO_X, one using a real discount rate of 3 percent and another using a real discount rate of 7 percent.[42]

DOE is aware of multiple agency efforts to determine the appropriate range of values used in evaluating the potential economic benefits of reduced Hg emissions. DOE has decided to await further guidance regarding consistent valuation and reporting of Hg emissions before it once again monetizes Hg in its rulemakings.

V. Analytical Results

The following section addresses the results from DOE's analyses with respect to potential energy conservation standards for residential clothes washers of this rulemaking. It addresses the TSLs examined by DOE, the projected impacts of each of these levels if adopted as energy conservation standards for clothes washers, and the standards levels that DOE sets forth in today's direct final rule. Additional details regarding DOE's analyses are contained in the publicly available direct final rule TSD supporting this notice.

A. Trial Standard Levels

DOE analyzed the benefits and burdens of a number of TSLs for residential clothes washers, the products that are the subject of today's direct final rule. Each TSL DOE analyzed is described below. DOE attempted to limit the number of TSLs considered for the final rule by excluding efficiency levels that do not exhibit significantly different economic and/or engineering characteristics from the efficiency levels already selected as a TSL. Although DOE presents the results for only those efficiency levels in TSL combinations in today's final rule, DOE presents the results for all efficiency levels that it analyzed in the final rule TSD.

Table V–1 presents the TSLs and the corresponding product class efficiency levels for clothes washers.

For standard-size products, TSL 1 consists of the efficiency levels that are two levels above the baseline levels (which are considered Efficiency Level 0). TSL 2 represents an intermediary point between the efficiency levels chosen for TSL 1 and the efficiency levels recommended in the Joint Petition. TSL 3 consists of the efficiency levels recommended in the Joint Petition. In the case of TSL 3, for top-loading standard clothes washers, one set of values would apply starting in 2015, and another set would apply starting in 2018. TSL 4 consists of the efficiency levels that are one level below the max-tech efficiency levels. TSL 5 consists of the max-tech efficiency levels.

For top-loading compacts, TSL 1, TSL 2 and the 2015 level of TSL 3 consists of Efficiency Level 1, and TSL 4 and TSL 5 and the 2018 level of TSL 3 consist of Efficiency Level 2. For front-loading compacts, all TSLs consist of Efficiency Level 1.

TABLE V–1—TRIAL STANDARD LEVELS FOR RESIDENTIAL CLOTHES WASHERS

TSL	Top-loading standard			Front-loading standard		
	Efficiency level	IMEF ft³/kWh/cycle	Standby W	Efficiency level	IMEF ft³/kWh/cycle	Standby W
1	2	1.29	0.00	2	1.41	0.08
2	5	1.37	0.08	4	1.66	0.08
3*	2	1.29	0.00	5	1.84	0.08
3**	6	1.57	0.08			
4	7	1.83	0.08	7	2.20	0.08
5	8	2.04	0.08	8	2.46	0.08
	Top-loading compact			Front-loading compact		
1	1	0.86	0.00	1	1.13	0.08
2	1	0.86	0.00	1	1.13	0.08
3*	1	0.86	0.00	1	1.13	0.08
3**	2	1.15	2.30			
4	2	1.15	2.30	1	1.13	0.08
5	2	1.15	2.30	1	1.13	0.08

* 2015 levels.
** 2018 levels.

[41] For additional information, refer to U.S. Office of Management and Budget, Office of Information and Regulatory Affairs. *2006 Report to Congress on the Costs and Benefits of Federal Regulations and Unfunded Mandates on State, Local, and Tribal Entities.* 2006. Washington, DC.

[42] OMB, Circular A–4: Regulatory Analysis (Sept. 17, 2003).

B. Economic Justification and Energy Savings

1. Economic Impacts on Individual Consumers

a. Life-Cycle Cost and Payback Period

Consumers affected by new or amended standards usually experience higher purchase prices and lower operating costs. Generally, the impacts on individual consumers are best captured by changes in life-cycle cost (LCC) and by the payback period (PBP). Therefore, DOE calculated the LCC and PBP analyses for the potential standard levels considered in this rulemaking. DOE's LCC and PBP analyses provided key outputs for each TSL, which are reported by clothes washer product class in Table V–2 through Table V–5. Each table includes the average total LCC and the average LCC savings, as well as the fraction of product consumers for which the LCC will decrease (net benefit), increase (net cost), or exhibit no change (no impact) relative to the base-case forecast. The last column in the tables contains the median PBP for the consumer purchasing a design that complies with the TSL. DOE presents the median PBP because it is the most statistically robust measure of the PBP. The results for each potential standard level are relative to the efficiency distribution in the base case (no amended standards). DOE based the LCC and PBP analyses on the range of energy consumption under conditions of actual product use.

TABLE V–2—LCC AND PBP RESULTS FOR TOP-LOADING STANDARD CLOTHES WASHERS

TSL	IMEF	Life-cycle cost *2010$*			LCC Savings				Payback period *years*
		Installed cost	Discounted operating cost	LCC	Average savings *2010$*	Percent of households that experience			Median
						Net cost	No impact	Net benefit	
1	1.29	425	1,317	1,743	268	0.7	19.5	79.8	0.4
2	1.37	433	1,340	1,773	243	5.6	15.1	79.3	0.7
3*	1.29	425	1,317	1,743	268	0.7	19.5	79.8	0.4
3**	1.57	448	1,182	1,630	366	3.4	14.1	82.5	0.9
4	1.83	496	1,003	1,499	491	8.1	4.6	87.4	1.8
5	2.04	508	958	1,466	524	9.5	0.0	90.5	1.9

*2015 levels.
**2018 levels.

TABLE V–3—LCC AND PBP RESULTS FOR FRONT-LOADING STANDARD CLOTHES WASHERS

TSL	IMEF	Life-cycle cost *2010$*			LCC Savings				Payback period *years*
		Installed cost	Discounted operating cost	LCC	Average savings *2010$*	Percent of households that experience			Median
						Net cost	No impact	Net benefit	
1	1.41	867	1,214	2,081	0	0.0	100.0	0.0	NA
2	1.66	874	1,088	1,961	2.2	0.1	96.0	3.9	0.9
3	1.84	888	946	1,835	37	1.5	72.4	26.1	1.3
4	2.20	938	900	1,838	35	45.1	11.6	43.3	9.2
5	2.46	964	807	1,771	102	29.6	0.0	70.4	5.2

TABLE V–4—LCC AND PBP RESULTS FOR TOP-LOADING COMPACT CLOTHES WASHERS

TSL	IMEF	Life-cycle cost *2010$*			LCC Savings				Payback period *years*
		Installed cost	Discounted operating cost	LCC	Average savings *2010$*	Percent of households that experience			Median
						Net cost	No impact	Net benefit	
1	0.86	426	988	1,414	159	1.5	0.0	98.5	0.5
2	0.86	426	988	1,414	159	1.5	0.0	98.5	0.5
3*	0.86	426	988	1,414	159	1.5	0.0	98.5	0.5
3**	1.15	480	781	1,261	312	12.6	0.0	87.4	2.1
4	1.15	480	781	1,261	312	12.6	0.0	87.4	2.1
5	1.15	480	781	1,261	312	12.6	0.0	87.4	2.1

*2015 levels.
**2018 levels.

TABLE V–5—LCC AND PBP RESULTS FOR FRONT-LOADING COMPACT CLOTHES WASHERS

TSL	IMEF	Life-cycle cost *2010$*			LCC Savings				Payback period *years*
		Installed cost	Discounted operating cost	LCC	Average savings *2010$*	Percent of households that experience			Median
						Net cost	No impact	Net benefit	
1	1.13	865	694	1,559	54	0.0	0.0	100.0	0.8
2	1.13	865	694	1,559	54	0.0	0.0	100.0	0.8
3	1.13	865	694	1,559	54	0.0	0.0	100.0	0.8
4	1.13	865	694	1,559	54	0.0	0.0	100.0	0.8

TABLE V–5—LCC AND PBP RESULTS FOR FRONT-LOADING COMPACT CLOTHES WASHERS—Continued

TSL	IMEF	Life-cycle cost *2010$*			LCC Savings				Payback period *years*
		Installed cost	Discounted operating cost	LCC	Average savings *2010$*	Percent of households that experience			Median
						Net cost	No impact	Net benefit	
5	1.13	865	694	1,559	54	0.0	0.0	100.0	0.8

b. Consumer Sub-Group Analysis

As described in section IV.H, DOE determined the impact of the considered TSLs on low-income households and senior-only households. Table V–6 compares the average LCC savings at each efficiency level for the two consumer subgroups, along with the average LCC savings for the entire sample for each product class for clothes washers. For compacts, DOE also analyzed impacts on multi-family consumers, since they are most likely to use compact washers. In general, the average LCC savings for low-income households and senior-only households at the considered efficiency levels are not substantially different from the average for all households. Chapter 11 of the direct final rule TSD presents the complete LCC and PBP results for the consumer subgroups.

TABLE V–6—CLOTHES WASHERS: COMPARISON OF AVERAGE LCC SAVINGS FOR CONSUMER SUBGROUPS AND ALL HOUSEHOLDS

TSL	Top-loading standard				Front-loading standard			
	IMEF	Senior	Low-income	All	IMEF	Senior	Low-income	All
1	1.29	163	240	268	1.41	0	0	0
2	1.37	142	203	243	1.66	1.3	2.5	2.2
3 *	1.29	163	240	268	1.84	22	36	37
3 **	1.57	214	319	366				
4	1.83	275	437	491	2.20	6.0	39	35
5	2.04	291	466	524	2.46	38	109	102

TSL	Top-loading compact					Front-loading compact				
	IMEF	Senior	Low-income	Multi-family	All	IMEF	Senior	Low-income	Multi-family	All
1	0.86	99	150	127	159	1.13	41	57	48	54
2	0.86	99	150	127	159	1.13	41	57	48	54
3 *	0.86	99	150	127	159	1.13	41	57	48	54
3 **	1.15	163	275	227	312	1.13				
4	1.15	163	275	227	312	1.13	41	57	48	54
5	1.15	163	275	227	312	1.13	41	57	48	54

* Refers to 2015 levels for top-loading washers.
** Refers to 2018 levels for top-loading washers.

c. Rebuttable Presumption Payback

As discussed above, EPCA provides a rebuttable presumption that an energy conservation standard is economically justified if the increased purchase cost for a product that meets the standard is less than three times the value of the first-year energy savings resulting from the standard. In calculating a rebuttable presumption payback period for the considered standard levels, DOE used discrete values rather than distributions for input values, and, as required by EPCA, based the energy use calculation on the DOE test procedures for residential clothes washers. As a result, DOE calculated a single rebuttable presumption payback value, and not a distribution of payback periods, for each efficiency level. Table V–7 presents the average rebuttable presumption payback periods for those efficiency levels where the increased purchase cost for a product that meets a standard at that level is less than three times the value of the first-year energy savings resulting from the standard.

TABLE V–7—CLOTHES WASHERS: EFFICIENCY LEVELS HAVING REBUTTABLE PBPS LESS THAN THREE YEARS

TSL	Top-loading standard		Front-loading standard		Top-loading compact		Front-loading compact	
	IMEF	PBP *years*	IMEF	PBP *years*	IMEF	PBP *years*	IMEF	PBP *years*
1	1.29	0.7	1.41	0.3	0.86	0.30	1.13	0.7
2	1.37	0.8	1.66	0.7	0.86	0.30	1.13	0.7
3 *	1.29	0.7	1.84	0.5	0.86	0.30	1.13	0.7
3 **	1.57	1.7			1.15	1.31	1.13	0.7
4	1.83	2.1	2.20	1.1	1.15	1.31	1.13	0.7
5	2.04	2.2	2.46	1.2	1.15	1.31	1.13	0.7

* Refers to 2015 levels for top-loading washers.
** Refers to 2018 levels for top-loading washers.

While DOE examined the rebuttable-presumption criterion, it considered whether the standard levels considered for today's rule are economically justified through a more detailed analysis of the economic impacts of those levels pursuant to 42 U.S.C. 6295(o)(2)(B)(i). The results of that analysis serve as the basis for DOE to evaluate the economic justification for a potential standard level (thereby supporting or rebutting the results of any preliminary determination of economic justification).

2. Economic Impacts on Manufacturers

DOE performed an MIA to estimate the impact of amended energy conservation standards on manufacturers of residential clothes washers. The section below describes the expected impacts on manufacturers at each TSL. Chapter 12 of the direct final rule TSD explains the analysis in further detail.

a. Industry Cash Flow Analysis Results

The tables below depict the financial impacts on manufacturers (represented by changes in INPV) and the conversion costs DOE estimates manufacturers would incur at each TSL. Each set of results below shows INPV impacts under a different set of assumptions: The first table reflects the lower (least severe) bound of impacts and the third table represents the upper (most severe) bound. As described in section IV.I, DOE modeled three different scenarios using different markup assumptions to evaluate this range of cash-flow impacts on the industry. These assumptions correspond to the bounds of a range of market responses that DOE anticipates could occur in the standards case. Each scenario results in a unique set of cash flows and corresponding industry value at each TSL.

The INPV results refer to the difference in industry value between the base case and the standards case, which DOE calculated by summing the discounted industry cash flows from the base year (2011) through the end of the analysis period. The discussion also notes the difference in cash flow between the base case and the standards case in the year before the compliance date of potential amended energy conservation standards. This figure provides a proxy for the magnitude of the required conversion costs relative to the cash flow generated by the industry in the base case.

To assess the lower end of the range of potential impacts on the residential clothes washer industry, DOE modeled the no commoditization markup scenario. The no commoditization scenario assumes that the baseline manufacturer markup structure does not change in the standards case. In this scenario, the higher markup for the 2011 ENERGY STAR level and the additional markup for CEE Tier 2 and Tier 3 products continue in the standards case. This scenario also assumes that manufacturers would be able to fully pass the higher production costs required for more efficient products on to their customers in the standards case. In general, the more standards reduce the ability to differentiate on efficiency and the larger the product price increases, the less likely manufacturers are to achieve the cash flow from operations calculated in this scenario because the less likely it is that manufacturers would be able to fully mark up these larger cost increases.

DOE also assessed two tiered markup scenarios, the tiered markup scenario and the tiered markup scenario with margin impacts. The latter represents the upper bound of the range of potential impacts on the industry. In the standards case, both tiered markup scenarios consider the situation in which the breadth of a manufacturer's portfolio of products shrinks as amended standards result in the elimination of lower efficiency tiers from the market and the erosion of premium markups for higher-tier products. These scenarios model a reduction in markups that manufacturers may experience under more stringent amended energy conservation standards as premium products earn the same markups previously held by lower efficiency tiers. In the tiered markup scenario with margin impacts, no additional operating profit is earned on the higher production costs of products that meet the minimum energy conservation standard in the standards case, eroding profit margins as a percentage of total revenue. In addition, as base-case efficiency differentiators are eliminated in the standards case, products that previously earned a premium markup move to lower efficiency markup tiers.

DOE used the reference NIA shipment scenario for all MIA scenarios used to characterize the potential INPV impacts. The shipment forecast is an important driver of the INPV results below (Table V–8 through Table V–10). The reference NIA shipment scenario includes two elasticity effects: (1) A relative price elasticity, which assumes higher product prices in the standards case result in lower shipments, and, in turn, lower industry revenue and INPV and (2) a cross-price elasticity, which changes the relative market share of top-loading and front-loading clothes washers as price increases alter their relative costs to consumers. The reference NIA shipment scenario also includes the default price forecast as described in chapter 10 of the direct final rule TSD.

TABLE V–8—MANUFACTURER IMPACT ANALYSIS FOR RESIDENTIAL CLOTHES WASHERS—NO COMMODITIZATION MARKUP SCENARIO

	Units	Base case	Trial standard level				
			1	2	3	4	5
INPV	(*2010$ millions*)	2,585.7	2,529.4	2,571.3	2,682.0	2,790.7	2,841.2
Change in INPV	(*2010$ millions*)		(56.3)	(14.3)	96.4	205.0	255.5
	(*%*)		−2.2%	−0.6%	3.7%	7.9%	9.9%
Product Conversion Costs	(*2010$ millions*)		22.6	41.6	107.5	204.3	210.8
Capital Conversion Costs	(*2010$ millions*)		81.2	107.7	311.0	487.4	502.9
Total Conversion Costs.	(*2010$ millions*)		103.9	149.3	418.5	691.8	713.7

TABLE V–9—MANUFACTURER IMPACT ANALYSIS FOR RESIDENTIAL CLOTHES WASHERS—TIERED MARKUP SCENARIO

	Units	Base case	Trial standard level				
			1	2	3	4	5
INPV	(*2010$ millions*)	2,585.7	2,529.4	2,110.0	1,762.8	1,453.0	1,417.5
Change in INPV	(*2010$ millions*)		(56.3)	(475.7)	(822.9)	(1,132.7)	(1,168.1)
	(*%*)		−2.2%	−18.4%	−31.8%	−43.8%	−45.2%
Product Conversion Costs	(*2010$ millions*)		22.6	41.6	107.5	204.3	210.8
Capital Conversion Costs	(*2010$ millions*)		81.2	107.7	311.0	487.4	502.9
Total Conversion Costs.	(*2010$ millions*)		103.9	149.3	418.5	691.8	713.7

TABLE V–10—MANUFACTURER IMPACT ANALYSIS FOR RESIDENTIAL CLOTHES WASHERS—TIERED MARKUP SCENARIO WITH MARGIN IMPACTS

	Units	Base case	Trial standard level				
			1	2	3	4	5
INPV	(*2010$ millions*)	2,585.7	2,521.7	2,095.3	1,726.9	1,329.3	1,250.4
Change in INPV	(*2010$ millions*)		(64.0)	(490.3)	(858.8)	(1,256.4)	(1,335.3)
	(*%*)		−2.5%	−19.0%	−33.2%	−48.6%	−51.6%
Product Conversion Costs	(*2010$ millions*)		22.6	41.6	107.5	204.3	210.8
Capital Conversion Costs	(*2010$ millions*)		81.2	107.7	311.0	487.4	502.9
Total Conversion Costs.	(*2010$ millions*)		103.9	149.3	418.5	691.8	713.7

At TSL 1, DOE estimates impacts on INPV to range −$56.3 million to −$64.0 million, or a change in INPV of −2.2 percent to −2.5 percent. At this level, industry free cash flow is estimated to decrease by approximately 20.2 percent to $170.0 million, compared to the base-case value of $213.1 million in the year leading up to the amended energy conservation standards.

Because the top-loading and front-loading standard clothes washers comprise over 98 percent of the total residential clothes washer shipments, the vast majority of the INPV impacts come from the standard-size product classes. At TSL 1, most impacts on both INPV and free cash flow stem from the modest changes required for top-loading standard clothes washers because all of the front-loading standard residential clothes washers on the market today already meet standards at this level. For top-loading clothes washers, of which only 13 percent of the market currently meets standards proposed at TSL 1, the impacts on INPV and free cash flow arise from increases in upfront investment for product development and, to a lesser extent, the per-unit component costs required to achieve this efficiency level. TSL 1 would require investments in product redesign and improvements to facilities totaling approximately $103.9 million in an industry with base-case annual revenues of more than $4.4 billion in the year the standards go into effect. Regarding increases in component costs, the design options used to meet standards at TSL 1 include component changes such as electronic controls, agitator modification, and basket modifications. For top-loading standard residential clothes washers, these changes contribute only $8.44 (3.4 percent) to arrive at an MPC of $256.09. In summation, the cumulative effect on INPV and free cash flow is minimal largely because all front-loading standard products and some top-loading standard products already meet the efficiencies required at TSL 1, and the design changes for the top-loading standard products that do not meet the efficiency required at TSL1 would impose minimal costs. Further, as the efficiencies required at TSL 1 are well below ENERGY STAR levels, manufacturers are likely to retain the premiums they currently see across the full range of product efficiencies.

At TSL 2, DOE estimates impacts on INPV to range −$14.3 million to −$490.3 million, or a change in INPV of −0.6 percent to −19.0 percent. At this level, industry free cash flow is estimated to decrease by approximately

28.4 percent to $152.6 million, compared to the base-case value of $213.1 million in the year leading up to the amended energy conservation standards.

Because the top-loading and front-loading standard clothes washers comprise over 98 percent of the total residential clothes washer shipments, the vast majority of the INPV impacts come from the standard-size product classes. At TSL 2, the impacts on INPV and free cash flow result from higher per-unit costs for both top-loading and front-loading standard-sized product classes as well as increases in product and capital conversion costs for both of these product classes. The design options used to meet standards at TSL 2 for top-loading standard-size products include additional component changes to enable higher spin speeds and better control beyond the improvements to electronic controls and the agitator and basket associated with TSL 1. For front-loading standard-size products, TSL 2 is achieved by the use of an electronic user interface. The resulting MPC for top-loading standard residential clothes washers is approximately $261.88 at TSL 2, a $14.23 (5.7 percent) increase over current baseline units and similar to the incremental costs at TSL 1. For front-loading standard residential clothes washers, the MPC is approximately $524.33, a $6.20 (1.2 percent) increase from the baseline. The product redesign and incorporation of these changes into manufacturing lines requires approximately $149.3 million in total conversion costs—a $45.4 million increase from TSL 1. TSL 2 brings all front-loading standard washers up to current ENERGY STAR standard levels. The most severe impact to INPV at TSL 2 is the result of margin compression on front-loading standard clothes washers as manufacturers forfeit premiums and cut into margins as they try to maintain a marginally compliant competitively priced entry level product. While only a small fraction of front-loading clothes washers (4 percent of shipments) would be impacted in the standards case at TSL2, in the tiered markup scenario with margin compression the profitability impacts on front-loading clothes washers has a disproportionately large negative impact on INPV because most of the market is ENERGY STAR compliant in the base case.

At TSL 3, DOE estimates impacts on INPV to range $96.4 million to −$858.8 million, or a change in INPV of 3.7 percent to −33.2 percent. At this level, industry free cash flow is estimated to decrease by approximately 3.6 percent to $205.5 million, compared to the base-case value of $213.1 million in the year leading up to the amended energy conservation standards in 2015.

At TSL3, the largest impacts to free cash flow and INPV stem from the substantial upfront investments required to achieve this efficiency level. While the efficiency requirements for top-loading standard clothes washers in 2015 require incremental changes to existing products, the 2018 efficiency requirements for top-loading standard clothes washers are more substantial. Because only 9 percent of current shipments of top-loading standard clothes washers meet the 2018 efficiency standards established at TSL 3, manufacturing products to meet the 2018 standards would require large investments in product redesign and conversion of facilities. Substantial investments would also be required for manufacturers to meet the 2015 front-loading standard. The total conversion cost required to meet the 2015 and 2018 standards at TSL 3 is approximately $418.5 million—a substantial fraction of overall industry value and $269.2 million higher than at TSL 2. Less than 25 percent of the conversion costs associated with TSL 3 can be attributed to the 2015 compliance for top-loading standard products.. This is a considerably smaller factor than at TSL 1 and TSL 2 at which 97 percent and 81 percent of conversion costs can be attributed to standard top-loading compliance, respectively. The design options used to meet the 2015 front-loading and 2018 top-loading standards at TSL 3 include larger unit capacities, damping systems, and reinforced structural elements. Substantial changes to existing production facilities would be required to manufacture products to incorporate the 2015 front-loading and 2018 top-loading design options. Several manufacturers have already introduced products that meet the 2015 front-loading standard and 2018 top-loading standard efficiency levels, which mitigates the required changes to production facilities for these manufacturers. The compliance dates of TSL 3 also mitigate the effect of the large conversion costs required to meet the 2018 top-loading standards, subjecting the impact on cash flows to greater discounting while also allowing manufactures to delay or spread out their conversion costs. At TSL 3, the MPC for top-loading standard residential clothes washers is $256.09 to meet the 2015 energy conservation standard and $272.93 to meet the 2018 energy conservation standard. For front-loading standard residential clothes washers the MPC is approximately $535.38 to meet the 2015 energy conservation standard. For the 2015 standard this is a $8.44 (3.4 percent) increase for top-loading standard clothes washers and a $17.25 (3.3 percent) increase for front-loading standard clothes washers. For the 2018 energy conservation standard for top-loading standard clothes washers, this is a $25.28 (10.2 percent) increase. In the scenario in which manufacturers see no commoditization of higher efficiency clothes washers, the modest increases to MPC translate to higher margins sufficient to offset the initial capital investments and product design costs over the 30 year analysis period. In contrast in the tiered mark up scenario, because TSL 3 sets standards for top-loading standard clothes washers at current ENERGY STAR levels and standards for front-loading standard clothes washers above these levels, manufacturers lose their premium markup for high efficiency standard-size product classes leading to a substantial reduction in future revenues and subsequently in INPV.

At TSL 4, DOE estimates impacts on INPV to range $205.0 million to −$1,256.4 million, or a change in INPV of 7.9 percent to −48.6 percent. At this level, industry free cash flow is estimated to decrease by approximately 130.7 percent to −$65.5 million, compared to the base-case value of $213.1 million in the year leading up to the amended energy conservation standards.

Much like TSL 3, the impacts to INPV at TSL 4 result primarily from the substantial upfront investments required to achieve the amended efficiency levels for standard-size products, the incremental increases in per-unit costs, and the potential margin impacts. For top-loading units, in contrast to TSL 3, manufacturers are required to cover the conversion costs for all products by 2015. Manufacturing products to meet standards for both standard-size product classes at TSL 4 may require a complete platform overhaul, resulting in significant investments in both product redesign and the conversion of facilities. The total conversion cost required to meet standards at TSL 4 is approximately $691.8 million—a $273.3 million increase from TSL 3. The design options used to meet standards at TSL 4 include changes such as larger capacity, accelerometers, and better control technology beyond what is required for TSL 3. The resulting MPC for top-loading standard residential clothes washers at TSL 4 is approximately $308.30, and approximately $572.01 for front-loading standard residential clothes washers. This is a $60.65 (24.5 percent) and a $53.88 (10.4 percent) increase from the baseline for top-loading and front-loading standard residential clothes washers, respectively. This increase in MPC translates to a 3.5 percent decrease in 2015 shipments. However, the impact on INPV arising from a decrease in shipments from price elasticity is minor in comparison to that stemming from product commoditization and margin impacts as analyzed in the tiered markup scenario with margin impacts for standard-sized product classes. As TSL 4 brings standards for both top-loading and front-loading standard products above current ENERGY STAR levels, the fraction of products that are eligible for any additional markup above the baseline is further reduced as manufacturers sacrifice margins as they continue to seek to maintain a low-price-point basic product offering.

At TSL 5, DOE estimates impacts on INPV to range $255.5 million to −$1,335.3 million, or a change in INPV of 9.9 percent to −51.6 percent. At this level, industry free cash flow is estimated to decrease by approximately 134.9 percent to −$74.3 million, compared to the base-case value of $213.1 million in the year leading up to the amended energy conservation standards.

TSL 5 represents the max-tech efficiency level for both top-loading and front-loading standard clothes washers. The effects on INPV result from similar sources as TSL 4, including the substantial upfront investments required to achieve the amended efficiency levels, the incremental increases in per-unit costs, and the potential margin impacts. These effects, however, are compounded by the higher upfront investments for facility improvements and product development, the additional increases to the MPC, and the collapse of manufacturer margins as analyzed in the tiered markup scenario with margin impacts. At present, the market share of commercially available residential clothes washers that conform to this standard is negligible. As such, standards will affect nearly all platforms and manufacturers will incur substantial conversion costs associated with total redesigns and improvements to all production facilities. The total conversion cost required to meet standards at TSL 5 is approximately $713.7 million—a $21.9 million increase from TSL 4. TSL 5 does not delay compliance for the more stringent standard either top-loading product class, so manufacturers will incur all product and capital conversion costs by 2015, leading to a larger negative impact on INPV. The MPC for top-loading standard residential clothes washers is approximately $317.44 at TSL 5, and approximately $591.64 for front-loading standard residential clothes washers. This is a $69.79 (28.2 percent) and a $73.51 (14.2 percent) increase from the baseline for top-loading and front-loading standard residential clothes washers, respectively. However, the increase in per-unit production costs at TSL 5 relative to those at TSL 4 is comparatively small and involves only minimal incremental design options such as changes to load size sensors and more precise dispensing of laundry detergent and additives. With the increase in MPCs, 2015 shipments are forecast to decrease by approximately 4.4 percent at TSL 5. However, the impact on INPV arising from a decrease in shipments from price elasticity is minor in comparison to that stemming from product commoditization and margin impacts as analyzed in the tiered markup scenario with margin impacts. Where TSL 4 still provided some room for markups above the most basic units, TSL 5 sets the standard for all products as high as technically feasible, leaving manufacturers no ability to differentiate products by efficiency. Thus, all margins collapse to their lowest levels.

b. Impacts on Employment

DOE used the GRIM to estimate the domestic labor expenditures and number of domestic production workers in the base case and at each TSL from 2011 to 2044. DOE used statistical data from the most recent U.S. Census Bureau's 2009 ''Annual Survey of Manufacturers,'' the results of the engineering analysis, and interviews with manufacturers to determine the inputs necessary to calculate industry-wide labor expenditures and domestic employment levels. Labor expenditures for the manufacture of a product are a function of the labor intensity of the product, the sales volume, and an assumption that wages in real terms remain constant.

In the GRIM, DOE used the labor content of each product and the manufacturing production costs from the engineering analysis to estimate the annual labor expenditures in the residential clothes washer industry. DOE used Census data and interviews with manufacturers to estimate the portion of the total labor expenditures that is attributable to domestic labor.

The production worker estimates in this section cover only workers up to the line-supervisor level who are directly involved in fabricating and assembling a product within an Original Equipment Manufacturer (OEM) facility. Workers performing services that are closely associated with production operations, such as material handing with a forklift, are also included as production labor. DOE's estimates account only for production workers who manufacture the specific products covered by this rulemaking.

The employment impacts shown in Table V–11 represent the potential production employment that could result following amended energy conservation standards. The upper end of the results in this table estimates the total potential increase in the number of production workers after amended energy conservation standards. To calculate the total potential increase, DOE assumed that manufacturers continue to produce the same scope of covered products in domestic production facilities and domestic production is not shifted to lower-labor-cost countries. Because there is a real risk of manufacturers evaluating sourcing decisions in response to amended energy conservation standards, the lower end of the range of employment results in Table V–11 includes the estimated total number of U.S. production workers in the industry who could lose their jobs if all existing production were moved outside of the United States. While the results present a range of employment impacts following the compliance date of amended energy conservation standards, the discussion below also includes a qualitative discussion of the likelihood of negative employment impacts at the various TSLs. Finally, the employment impacts shown are independent of the employment impacts from the broader U.S. economy, which are documented in chapter 13 of the direct final rule TSD.

Using the GRIM, DOE estimates that in the absence of amended energy conservation standards, there would be 8,990 domestic production workers involved in manufacturing residential clothes washers in 2015. Using 2009 Census Bureau data and interviews with manufacturers, DOE estimates that approximately 70 percent of residential clothes washers sold in the United States are manufactured domestically. Table V–11 shows the range of the impacts of potential amended energy conservation standards on U.S. production workers in the clothes washer industry.

TABLE V–11—POTENTIAL CHANGES IN THE TOTAL NUMBER OF DOMESTIC RESIDENTIAL CLOTHES WASHER PRODUCTION WORKERS IN 2015

	Base case	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5
Total Number of Domestic Production Workers in 2015 (without changes in production locations)	8,990	9,058	9,164	9,080	9,376	8,604
Potential Changes in Domestic Production Workers in 2015*	....	68–(8,890)	174–(8,890)	90–(8,890)	386–(8,890)	(386)–(8,890)

* DOE presents a range of potential employment impacts. Numbers in parentheses indicate negative numbers.

All examined TSLs show relatively minor impacts on domestic employment levels relative to total industry employment at the lower end of the range of impacts. At all TSLs, most of the design options analyzed by DOE do not greatly alter the labor content of the final product. For example, more complex wash cycles or larger basket sizes involve one-time changes to the final product but do not significantly change the number of steps required for the final assembly of the clothes washer (which would add labor). Because many manufacturers have recently introduced high efficiency products in the United States that meet or exceed the standards in today's final rule, it is unlikely today's direct final rule would greatly impact the sourcing decisions of these manufacturers. However, at higher TSLs, some of the design options analyzed greatly impact the ability of manufacturers to make product changes within existing platforms. The very large upfront capital costs at these levels (especially for introducing new front-loading clothes washer platforms) could influence the decision of manufacturers to relocate some or all of the domestic production of these clothes washers to lower labor cost countries.

c. Impacts on Manufacturing Capacity

Most shipments of top-loading residential clothes washers fall below the 2015 and 2018 amended energy conservation standards. However, in response to the EISA 2007 water factor requirements, multiple manufacturers have modified baseline products to comply with these more stringent regulations. These changes were incremental modifications to lower-efficiency platforms. The 2015 efficiency requirements would also involve modifications to lower-end platforms for top-loading clothes washers for all manufacturers, but would similarly not require completely new platforms at a significantly higher upfront cost. In addition, multiple manufacturers have recently introduced new top-loading clothes washers that meet substantially higher efficiencies than lower-end products at the baseline efficiency today. The introduction of these platforms mitigates the required capital conversion costs for the industry to meet the 2018 top-loading energy conservation standards. DOE believes that the mitigated capital conversion costs for manufacturers that have already introduced high-efficiency top-loading clothes washers, as well as the additional 3 years for all remaining manufacturers to meet the more efficient standards for top-loading clothes washers in 2018, will allow the industry to meet demand and continue to offer a full range of products after the compliance date.

More than 70 percent of front-loading shipments current meet the front-loading energy conservation standards in today's direct final rule. In addition, every manufacturer that ships front-loading clothes washers offers products at the amended energy conservation standard. Since manufacturers will not have to make extensive platform changes but will need to increase the production of existing product by the 2015 compliance date, the experience of multiple front-loading manufacturers that already produce standards-compliant front-loading clothes washers will allow the industry to meet the amended energy conservation standards proposed in the direct final rule.

d. Impacts on Sub-Groups of Manufacturers

Using average cost assumptions to develop an industry cash-flow estimate may not be adequate for assessing differential impacts among manufacturer subgroups. Small manufacturers, niche equipment manufacturers, and manufacturers exhibiting a cost structure substantially different from the industry average could be affected disproportionately. DOE analyzed the impacts to small business, as discussed in section VI.B. DOE did not identify any other subgroups for residential clothes washers for this rulemaking.

e. Cumulative Regulatory Burden

While any one regulation may not impose a significant burden on manufacturers, the combined effects of several impending regulations may have serious consequences for some manufacturers, groups of manufacturers, or an entire industry. Assessing the impact of a single regulation may overlook this cumulative regulatory burden. In addition to energy conservation standards, other regulations can significantly affect manufacturers' financial operations. Multiple regulations affecting the same manufacturer can strain profits and can lead companies to abandon product lines or markets with lower expected future returns than competing products. For these reasons, DOE conducts an analysis of cumulative regulatory burden as part of its rulemakings pertaining to appliance efficiency.

Manufacturers provided comment on some of these regulations during the framework stage of this rulemaking. DOE summarizes and addresses these comments in section IV.I.3.a. For the cumulative regulatory burden, DOE attempts to quantify or describe the impacts of other Federal regulations that have a compliance date within approximately 3 years of the compliance date of this rulemaking. Most of the major regulations that meet this criteria identified by DOE are other energy conservation standards for products and equipment made by manufacturers of residential clothes washers. See chapter 12 of the direct final rule TSD for the results of DOE's analysis of the cumulative regulatory burden.

3. National Impact Analysis

a. Significance of Energy Savings

To estimate the energy savings through 2044 attributable to potential standards for clothes washers, DOE compared the energy consumption of those products under the base case to their anticipated energy consumption under each TSL. Table V–12 presents DOE's forecasts of the national energy savings for each TSL for clothes washers, and Table V–13 presents forecasts of the national water savings.[43] The savings were calculated using the approach described in section IV.G. Chapter 10 of the direct final rule TSD presents tables that also show the magnitude of the energy savings if the savings are discounted at rates of 7 percent and 3 percent. Discounted energy savings represent a policy perspective in which energy savings realized farther in the future are less significant than energy savings realized in the nearer term.

TABLE V–12—CLOTHES WASHERS: CUMULATIVE NATIONAL ENERGY SAVINGS

Energy (quads)	Trial standard level				
	1	2	3	4	5
Standard Size	1.52	1.43	1.98	2.81	3.27
Compact Size	0.04	0.04	0.05	0.05	0.05

TABLE V–13—CLOTHES WASHERS: CUMULATIVE NATIONAL WATER SAVINGS

Water (trillion gallons)	Trial standard level				
	1	2	3	4	5
Standard Size	1.12	1.06	3.01	5.31	6.87
Compact Size	−0.01	−0.01	0.02	0.02	0.02

b. Net Present Value of Consumer Costs and Benefits

DOE estimated the cumulative NPV to the nation of the total costs and savings for consumers that would result from particular standard levels for clothes washers. In accordance with the OMB's guidelines on regulatory analysis (OMB Circular A–4, section E, September 17, 2003), DOE calculated NPV using both a 7-percent and a 3-percent real discount rate. The 7-percent rate is an estimate of the average before-tax rate of return to private capital in the U.S. economy, and reflects the returns to real estate and small business capital as well as corporate capital. DOE used this discount rate to approximate the opportunity cost of capital in the private sector, since recent OMB analysis has found the average rate of return to capital to be near this rate. In addition, DOE used the 3-percent rate to capture the potential effects of standards on private consumption (*e.g.,* through higher prices for products and the purchase of reduced amounts of energy). This rate represents the rate at which society discounts future consumption flows to their present value. This rate can be approximated by the real rate of return on long-term government debt (*i.e.,* yield on Treasury notes minus annual rate of change in the Consumer Price Index), which has averaged about 3 percent on a pre-tax basis for the last 30 years.

Table V–14 shows the consumer NPV results for each TSL DOE considered for clothes washers, using a 3-percent and a 7-percent discount rate. The impacts are counted over the lifetime of products purchased in 2015–2044.

TABLE V–14—CLOTHES WASHERS: CUMULATIVE NET PRESENT VALUE OF CONSUMER BENEFITS, 3- AND 7-PERCENT DISCOUNT RATE*

Discount rate	Trial standard level				
	1	2	3	4	5
	Billion 2010$				
3 percent:					
Standard	19.9	18.1	30.7	41.0	49.9
Compact	0.32	0.32	0.56	0.58	0.58
7 percent:					
Standard	8.6	7.6	12.8	16.2	19.7
Compact	0.14	0.14	0.23	0.24	0.24

* The impacts are counted over the lifetime of products purchased in 2015–2044.

The NPV results presented in Table V–14 are based on the default product price trend. As discussed in section IV.G.3, DOE developed several sensitivity cases with alternative forecasts of future prices of clothes washers. The impact of these alternative forecasts on the NPV results is presented in appendix 10–C of the direct final rule TSD.

Circular A–4 requires agencies to present analytical results, including separate schedules of the monetized benefits and costs that show the type and timing of benefits and costs. Circular A–4 also directs agencies to consider the variability of key elements underlying the estimates of benefits and costs. DOE believes its standard 30-year analysis is fully compliant with Circular A–4. For this rulemaking, DOE undertook an additional sensitivity analysis of its standard 30-year analysis, in compliance with Circular A–4, using a 9-year analytical period. The choice of a 9-year period is a proxy for the

[43] National energy and water savings are cumulative over a 30-year period. Any savings for products entering the housing stock in this 30-year period which occur beyond the 30-year time limit are not reported in the national totals.

timeline in EPCA for the review of the energy conservation standard established in this direct final rule and potential revision of and compliance with a new standard for clothes washers.[44] The review timeframe established in EPCA generally does not overlap with the product lifetime, product manufacturing cycles or other factors specific to residential clothes washers. Thus, this information is presented for informational purposes only and is not indicative of any change in DOE's analytical methodology.

The sensitivity analysis results based on a 9-year analytical period are presented below. Table V–15 presents DOE's forecasts of the national energy savings for each TSL for clothes washers, and Table V–16 presents forecasts of the national water savings.[45] Table V–17 shows the consumer NPV results for each TSL DOE considered for clothes washers, using a 3-percent and a 7-percent discount rate. For determination of the NPV, the impacts are counted over the lifetime of products purchased in 2015–2023 (note that the average lifetime of a clothes washer is 14.2 years, which is longer than the 9-year analysis period; thus, the NPV estimate incorporates all of the operating cost savings of clothes washers purchased in the 9 year analytical period).

TABLE V–15—CLOTHES WASHERS: CUMULATIVE NATIONAL ENERGY SAVINGS, NINE-YEAR ANALYSIS PERIOD

Energy (quads)	Trial standard level				
	1	2	3	4	5
Standard Size	0.23	0.21	0.27	0.41	0.48
Compact Size	0.01	0.01	0.01	0.01	0.01

TABLE V–16—CLOTHES WASHERS: CUMULATIVE NATIONAL WATER SAVINGS, NINE-YEAR ANALYSIS PERIOD

Water (trillion gallons)	Trial standard level				
	1	2	3	4	5
Standard Size	0.17	0.14	0.37	0.78	1.02
Compact Size	0.00	0.00	0.00	0.00	0.00

TABLE V–17—CLOTHES WASHERS: CUMULATIVE NET PRESENT VALUE OF CONSUMER BENEFITS, 3- AND 7-PERCENT DISCOUNT RATES, NINE-YEAR ANALYSIS PERIOD*

Discount rate	Trial standard level				
	1	2	3	4	5
	Billion 2010$				
3 percent:					
Standard	7.40	6.48	10.60	14.21	17.35
Compact	0.12	0.12	0.18	0.21	0.21
7 percent:					
Standard	4.31	3.68	5.99	7.53	9.18
Compact	0.07	0.07	0.10	0.12	0.12

* The impacts are counted over the lifetime of products purchased in 2015–2023.

c. Indirect Impacts on Employment

DOE develops estimates of the indirect employment impacts of potential standards on the economy in general. As discussed above, DOE expects energy conservation standards for clothes washers to reduce energy bills for consumers of those products, and the resulting net savings to be redirected to other forms of economic activity. Those shifts in spending and economic activity could affect the demand for labor. As described in section IV.J, DOE used an input/output model of the U.S. economy to estimate indirect employment impacts of the TSLs that DOE considered in this rulemaking. DOE understands that there are uncertainties involved in projecting employment impacts, especially changes in the later years of the analysis. Therefore, DOE generated results for near-term timeframes (2015–2020), where these uncertainties are reduced.

The results suggest that today's standards are likely to have negligible impact on the net demand for labor in the economy. The net change in jobs is so small that it would be imperceptible in national labor statistics and might be offset by other, unanticipated effects on employment. Chapter 13 of the direct final rule TSD presents more detailed results.

4. Impact on Utility or Performance of Products

As presented in section III.D.1.d of this notice, DOE concluded that the TSL adopted in this direct final rule would

[44] EPCA requires DOE to review its standards at least once every 6 years, and requires, for certain products including clothes washers, a 3 year period after any new standard is promulgated before compliance is required, except that in no case may any new standards be required within 6 years of the compliance date of the standards established in this direct final rule. While adding a 6-year review to the 3-year compliance period adds up to 9 years, DOE notes that it may undertake reviews at any time within the 6 year period and that the 3-year compliance date may yield to the 6-year backstop. A 9-year analysis period does not reflect the variability that may occur in the timing of standards reviews and the fact that for some consumer products, the compliance period is 5 years rather than 3 years.

[45] National energy and water savings are cumulative over the 9-year period. Any savings for products entering the housing stock in this 9-year period which occur beyond the 9-year time limit are not reported in the national totals.

not reduce the utility or performance of the clothes washers under consideration in this rulemaking. Manufacturers of these products currently offer units that meet or exceed today's standards. (42 U.S.C. 6295(o)(2)(B)(i)(IV))

5. Impact of Any Lessening of Competition

DOE has also considered any lessening of competition that is likely to result from amended standards. The Attorney General determines the impact, if any, of any lessening of competition likely to result from a proposed standard, and transmits such determination to DOE, together with an analysis of the nature and extent of such impact. (42 U.S.C. 6295(o)(2)(B)(i)(V) and (B)(ii))

DOE published a NOPR containing energy conservation standards identical to those set forth in today's direct final rule and transmitted a copy of today's direct final rule and the accompanying TSD to the Attorney General, requesting that the DOJ provide its determination on this issue. DOE will consider DOJ's comments on the rule in determining whether to proceed with the direct final rule. DOE will also publish and respond to DOJ's comments in the **Federal Register** in a separate notice.

6. Need of the Nation To Conserve Energy

An improvement in the energy efficiency of the products subject to today's rule is likely to improve the security of the nation's energy system by reducing overall demand for energy. Reduced electricity demand may also improve the reliability of the electricity system. As a measure of this reduced demand, Table V–18 presents the estimated reduction in electricity generating capacity in 2044 for the TSLs that DOE considered in this rulemaking.

TABLE V–18—REDUCTION IN ELECTRIC GENERATING CAPACITY IN 2044 UNDER TRIAL STANDARD LEVELS FOR CLOTHES WASHERS

	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5
	Gigawatts				
Clothes Washers	0.882	1.01	1.30	1.64	1.86

Energy savings from amended standards for clothes washers are expected to produce environmental benefits in the form of reduced emissions of air pollutants and greenhouse gases associated with electricity production. Table V–19 provides DOE's estimate of cumulative CO_2, NO_X, and Hg emissions reductions that would be expected to result from the TSLs considered in this rulemaking. In the emissions analysis (chapter 15 of the direct final rule TSD), DOE reports annual CO_2, NO_X, and Hg emissions reductions for each TSL.

As discussed in section IV.L, DOE has not reported SO_2 emissions reductions from power plants because SO_2 emissions caps have created uncertainty about the effect of energy conservation standards on the overall level of SO_2 emissions in the United States. DOE also did not include NO_X emissions reduction from power plants in States subject to CAIR because the emissions caps mandated by CAIR mean that an energy conservation standard would not affect the overall level of NO_X emissions in those States.[46]

TABLE V–19—EMISSIONS REDUCTION ESTIMATED FOR CLOTHES WASHER TRIAL STANDARD LEVELS

[Cumulative in 2015–2044]

	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5
CO_2 (*million metric tons*)	87.65	81.96	112.90	155.51	178.82
NO_X (*thousand tons*)	73.46	68.07	94.16	130.10	149.70
Hg (*tons*)	0.198	0.226	0.269	0.364	0.413

DOE also estimated monetary benefits likely to result from the reduced emissions of CO_2 and NO_X that DOE estimated for each of the TSLs considered for clothes washers. As discussed in section IV.M, DOE used values for the SCC developed by an interagency process. The four values for CO_2 emissions reductions resulting from that process (expressed in 2010$) are $4.9/ton (the average value from a distribution that uses a 5-percent discount rate), $22.3/ton (the average value from a distribution that uses a 3-percent discount rate), $36.5/ton (the average value from a distribution that uses a 2.5-percent discount rate), and $67.6/ton (the 95th-percentile value from a distribution that uses a 3-percent discount rate). These values correspond to the value of emission reductions in 2010; the values for later years are higher due to increasing damages as the magnitude of climate change increases. For each of the four cases, DOE calculated a present value of the stream of annual values using the same discount rate as used in the studies upon which the dollar-per-ton values are based. Table V–20 presents the global values of CO_2 emissions reductions at each TSL. DOE calculated domestic values as a range from 7 percent to 23 percent of the global values. Those results are presented in Table V–21.

[46] The analysis for today's rule assumes the implementation of CAIR and does not take into account the recently issued (July 6, 2011) Cross-State Air Pollution Rule. In future rulemakings, DOE will adjust its relevant models to reflect the implementation of the Cross-State Air Pollution Rule.

TABLE V–20—ESTIMATES OF GLOBAL PRESENT VALUE OF CO_2 EMISSIONS REDUCTIONS UNDER CLOTHES WASHER TRIAL STANDARD LEVELS

TSL	Million 2010$			
	5% discount rate, average*	3% discount rate, average*	2.5% discount rate, average*	3% discount rate, 95th percentile*
1	410	2143	3645	6527
2	384	2007	3414	6112
3	530	2777	4727	8457
4	729	3813	6488	11613
5	838	4386	7462	13357

* Columns are labeled by the discount rate used to calculate the SCC and whether it is an average value or drawn from a different part of the distribution.

TABLE V–21—ESTIMATES OF DOMESTIC PRESENT VALUE OF CO_2 EMISSIONS REDUCTIONS UNDER CLOTHES WASHER TRIAL STANDARD LEVELS

TSL	Million 2010$*			
	5% discount rate, average**	3% discount rate, average**	2.5% discount rate, average**	3% discount rate, 95th percentile**
1	29 to 94	150 to 493	255 to 838	457 to 1501.
2	27 to 88	140 to 462	239 to 785	428 to 1406.
3	37 to 122	194 to 639	331 to 1087	592 to 1945.
4	51 to 168	267 to 877	454 to 1492	813 to 2671.
5	59 to 193	307 to 1009	522 to 1716	935 to 3072.

* Domestic values are presented as a range between 7 percent and 23 percent of the global values.
** Columns are labeled by the discount rate used to calculate the SCC and whether it is an average value or drawn from a different part of the distribution.

DOE is well aware that scientific and economic knowledge about the contribution of CO_2 and other GHG emissions to changes in the future global climate and the potential resulting damages to the world economy continues to evolve rapidly. Thus, any value placed in this rulemaking on reducing CO_2 emissions is subject to change. DOE, together with other Federal agencies, will continue to review various methodologies for estimating the monetary value of reductions in CO_2 and other GHG emissions. This ongoing review will consider the comments on this subject that are part of the public record for this and other rulemakings, as well as other methodological assumptions and issues. However, consistent with DOE's legal obligations, and taking into account the uncertainty involved with this particular issue, DOE has included in this final rule the most recent values and analyses resulting from the ongoing interagency review process.

DOE also estimated a range for the cumulative monetary value of the economic benefits associated with NO_X emissions reductions anticipated to result from amended standards for clothes washers. The dollar-per-ton values that DOE used are discussed in section IV.M. Table V–22 presents the cumulative present values for each TSL calculated using 3-percent and 7-percent discount rates.

TABLE V–22—ESTIMATES OF PRESENT VALUE OF NO_X EMISSIONS REDUCTIONS UNDER CLOTHES WASHER TRIAL STANDARD LEVELS

TSL	3% discount rate *million 2010$*	7% discount rate *million 2010$*
1	22 to 224	9 to 97.
2	20 to 207	9 to 90.
3	28 to 286	12 to 122.
4	39 to 396	17 to 171.
5	44 to 456	19 to 197.

The NPV of the monetized benefits associated with emissions reductions can be viewed as a complement to the NPV of the consumer savings calculated for each TSL considered in this rulemaking. Table V–23 shows an example of the calculation of the combined NPV including benefits from emissions reductions for the case of TSL 3 for front-loading clothes washers. Table V–24 and Table V–25 present the NPV values that result from adding the estimates of the potential economic benefits resulting from reduced CO_2 and NO_X emissions in each of four valuation scenarios to the NPV of consumer savings calculated for each TSL considered in this rulemaking, at both a 7-percent and a 3-percent discount rate. The CO_2 values used in the columns of each table correspond to the four scenarios for the valuation of CO_2 emission reductions presented in section IV.M.

TABLE V–23—ADDING NET PRESENT VALUE OF CONSUMER SAVINGS TO PRESENT VALUE OF MONETIZED BENEFITS FROM CO_2 AND NO_X EMISSIONS REDUCTIONS AT TSL 3

Category	Present value *(billion 2010$)*	Discount rate *(%)*
Benefits		
Operating Cost Savings	15.3	7
	35.4	3

TABLE V–23—ADDING NET PRESENT VALUE OF CONSUMER SAVINGS TO PRESENT VALUE OF MONETIZED BENEFITS FROM CO_2 AND NO_X EMISSIONS REDUCTIONS AT TSL 3—Continued

Category	Present value *(billion 2010$)*	Discount rate *(%)*
CO_2 Reduction Monetized Value (at $4.9/t)*	0.53	5
CO_2 Reduction Monetized Value (at $22.3/t)*	2.78	3
CO_2 Reduction Monetized Value (at $36.5/t)*	4.73	2.5
CO_2 Reduction Monetized Value (at $67.6/t)*	8.46	3
NO_X Reduction Monetized Value (at $2,537/Ton)*	0.07	7
	0.16	3
Costs		
Total Incremental Installed Costs	2.30	7
	4.15	3
Net Benefits/Costs		
Net Benefits, Including CO_2 and NO_X**	15.9	7
	34.2	3

* These values represent global values (in 2010$) of the social cost of CO_2 emissions in 2010 under several scenarios. See section IV.M for a discussion of the derivation of these values. The value for NO_X (in 2010$) is the average of the low and high values used in DOE's analysis.
** Net Benefits for both the 3% and 7% cases utilize the central estimate of social cost of CO_2 emissions calculated at a 3% discount rate, which is equal to $21.4/ton in 2010 (in 2010$).

TABLE V–24—RESULTS OF ADDING NET PRESENT VALUE OF CONSUMER SAVINGS (AT 7% DISCOUNT RATE) TO NET PRESENT VALUE OF MONETIZED BENEFITS FROM CO_2 AND NO_X EMISSIONS REDUCTIONS UNDER CLOTHES WASHER TRIAL STANDARD LEVELS

TSL	Consumer NPV at 7% discount rate added with:			
	SCC Value of $4.9/metric ton CO_2* and low value for NO_X** *billion 2010$*	SCC Value of $22.3/metric ton CO_2* and medium value for NO_X** *billion 2010$*	SCC Value of $36.5/metric ton CO_2* and medium value for NO_X** *billion 2010$*	SCC Value of $67.6/metric ton CO_2* and high value for NO_X** *billion 2010$*
1	9.1	10.9	12.4	15.4
2	8.2	9.8	11.2	14.0
3	13.6	15.9	17.8	21.6
4	17.2	20.3	23.0	28.2
5	20.8	24.4	27.5	33.5

* These label values represent the global SCC of CO_2 in 2010, in 2010$. Their present values have been calculated with scenario-consistent discount rates. See section IV.M for a discussion of the derivation of these values.
** Low Value corresponds to $450 per ton of NO_X emissions. Medium Value corresponds to $2,537 per ton of NO_X emissions. High Value corresponds to $4,623 per ton of NO_X emissions.

TABLE V–25—RESULTS OF ADDING NET PRESENT VALUE OF CONSUMER SAVINGS (AT 3% DISCOUNT RATE) TO NET PRESENT VALUE OF MONETIZED BENEFITS FROM CO_2 AND NO_X EMISSIONS REDUCTIONS UNDER CLOTHES WASHER TRIAL STANDARD LEVELS

TSL	Consumer NPV at 3% discount rate added with:			
	SCC Value of $4.9/metric ton CO_2* and low value for NO_X** *billion 2010$*	SCC Value of $22.3/metric ton CO_2* and medium value for NO_X** *billion 2010$*	SCC Value of $36.5/metric ton CO_2* and medium value for NO_X** *billion 2010$*	SCC Value of $67.6/metric ton CO_2* and high value for NO_X** *billion 2010$*
1	20.6	22.4	23.9	26.9
2	18.9	20.6	22.0	24.8
3	31.8	34.2	36.2	40.0
4	42.4	45.6	48.3	53.6
5	51.4	55.1	58.2	64.3

* These label values represent the global SCC of CO_2 in 2010, in 2010$. Their present values have been calculated with scenario-consistent discount rates. See section IV.M for a discussion of the derivation of these values.
** Low Value corresponds to $450 per ton of NO_X emissions. Medium Value corresponds to $2,537 per ton of NO_X emissions. High Value corresponds to $4,623 per ton of NO_X emissions.

Although adding the value of consumer savings to the values of emission reductions provides a valuable perspective, two issues should be considered. First, the national operating cost savings are domestic U.S. consumer monetary savings that occur as a result of market transactions, while the value of CO_2 reductions is based on a global value. Second, the assessments of operating cost savings and CO_2 savings are performed with different methods that use quite different time frames for analysis. The national operating cost savings is measured for the lifetime of products shipped in 2015–2044. The SCC values, on the other hand, reflect the present value of all future climate-related impacts resulting from the emission of one ton of carbon dioxide in each year. These impacts continue well beyond 2100.

7. Other Factors

The Secretary of Energy, in determining whether a standard is economically justified, may consider any other factors that the Secretary deems to be relevant. (42 U.S.C. 6295(o)(2)(B)(i)(VI))) In developing the direct final rule, DOE has also considered the Joint Petition submitted to DOE. DOE recognizes the value of consensus agreements submitted by parties in accordance with 42 U.S.C. 6295(p)(4) and has weighed the value of such consensus in establishing the standards set forth in today's final rule. DOE has encouraged the submission of consensus agreements as a way to get diverse interested parties together, to develop an independent and probative analysis useful in DOE standard setting, and to expedite the rulemaking process. DOE also believes that standard levels recommended in the consensus agreement may increase the likelihood for regulatory compliance, while decreasing the risk of litigation.

C. Conclusion

When considering proposed standards, the new or amended energy conservation standard that DOE adopts for any type (or class) of covered product shall be designed to achieve the maximum improvement in energy efficiency that the Secretary determines is technologically feasible and economically justified. (42 U.S.C. 6295(o)(2)(A)) In determining whether a standard is economically justified, the Secretary must determine whether the benefits of the standard exceed its burdens to the greatest extent practicable, in light of the seven statutory factors discussed previously. (42 U.S.C. 6295(o)(2)(B)(i)) The new or amended standard must also ''result in significant conservation of energy.'' (42 U.S.C. 6295(o)(3)(B))

The Department considered the impacts of standards at each trial standard level, beginning with maximum technologically feasible level, to determine whether that level was economically justified. Where the max-tech level was not justified, DOE then considered the next most efficient level and undertook the same evaluation until it reached the highest efficiency level that is both technologically feasible and economically justified and saves a significant amount of energy.

To aid the reader as DOE discusses the benefits and/or burdens of each trial standard level, tables present a summary of the results of DOE's quantitative analysis for each TSL. In addition to the quantitative results presented in the tables, DOE also considers other burdens and benefits that affect economic justification. Those include the impacts on identifiable subgroups of consumers, such as low-income households and seniors, who may be disproportionately affected by a national standard. Section V.B.1 presents the estimated impacts of each TSL for these subgroups.

As background for the consideration of benefits from energy efficiency standards, DOE notes that the economics literature provides a wide-ranging discussion of how consumers trade off upfront costs and energy savings in the absence of government intervention. Much of this literature attempts to explain why consumers appear to undervalue energy efficiency improvements. This undervaluation suggests that regulation that promotes energy efficiency can produce significant net private gains (as well as producing social gains by, for example, reducing pollution). There is evidence that consumers undervalue future energy savings as a result of (1) a lack of information; (2) a lack of sufficient salience of the long-term or aggregate benefits; (3) excessive focus on the short term, in the form of inconsistent weighting of future energy cost savings relative to available returns on other investments; (4) computational or other difficulties associated with the evaluation of relevant tradeoffs; and (5) a divergence in incentives (that is, renter vs. owner or builder vs. purchaser). Other literature indicates that with less than perfect foresight and a high degree of uncertainty about the future, consumers may trade off these types of investments at a higher than expected rate between current consumption and uncertain future energy cost savings.

In DOE's current regulatory analysis, potential changes in the benefits and costs of a regulation due to changes in consumer purchase decisions are included in two ways. First, if consumers forego a purchase of a product in the standards case, this decreases sales for product manufacturers and the cost to manufacturers is included in the MIA. Second, DOE accounts for energy savings attributable only to products actually used by consumers in the standards case; if a regulatory option decreases the number of products used by consumers, this decreases the potential energy savings from an energy conservation standard. DOE provides detailed estimates of shipments and changes in the volume of product purchases in chapter 9 of the direct final rule TSD. However, DOE's current analysis does not explicitly control for heterogeneity in consumer preferences, preferences across subcategories of products or specific features, or consumer price sensitivity variation according to household income (Reiss and White, 2005).[47]

While DOE is not prepared at present to provide a fuller quantifiable framework for estimating the benefits and costs of changes in consumer purchase decisions due to an energy conservation standard, DOE is committed to developing a framework that can support empirical quantitative tools for improved assessment of the consumer welfare impacts of appliance standards. DOE has posted a paper that discusses the issue of consumer welfare impacts of appliance energy efficiency standards, and potential enhancements to the methodology by which these impacts are defined and estimated in the regulatory process.[48]

DOE also conducted an analysis of the impacts on consumer welfare of the standards on clothes washers that required compliance in January 2007. This analysis assumes consumers made washer purchase decisions optimally (*i.e.,* taking full account of the tradeoff between up-front cost and future energy costs) and infers welfare implications based on price and quantity changes that occurred around the time of the standard change. The analysis assumes the 2007 policy change sharply reduced supply of low-efficiency units, which in turn sharply increased demand for higher-efficiency units.

The analysis used market survey data on total sales of washers purchased in the United States, with measures for units sold and average price broken down by washer brand and model. Values are reported for each month. The data include a limited number of attributes for each model, plus a measure of energy efficiency in terms of kilowatt-hours per year (kWh/y) for standard usage. The analysis used the

[47] P.C. Reiss and M.W. White. Household Electricity Demand, Revisited. *Review of Economic Studies* (2005) 72, 853–883.

[48] Alan Sanstad. ''Notes on the Economics of Household Energy Consumption and Technology Choice.'' Lawrence Berkeley National Laboratory. 2010. Available online at: *www1.eere.energy.gov/buildings/appliance_standards/pdfs/consumer_ee_theory.pdf.*

kWh/y measure to proxy for washers that may have been closer and farther from the 2007 standard and ENERGY STAR specifications.

The net change in consumer welfare can be inferred from (a) the gain and/or loss from consumer welfare from increased purchases of higher-efficiency units minus (b) the loss in consumer welfare from reduced purchase of lower-efficiency units. Because washer units banned from manufacture in 2007 were still available for purchase for some months after the ban, observed changes in prices and quantities of the lower efficiency units facilitates estimation of (b). The data show that prices for these units increased slightly while quantities sold declined sharply. This suggests consumer welfare losses in (a) were modest. The data further show that prices of higher-efficiency units declined with the 2007 standard, in some cases markedly so. These price declines suggest that the welfare gains in (a) are quite substantial, and although the total gain cannot be inferred, any lower-bound estimate would indicate that these gains far exceed losses in (b).

These inferred gains to consumers from the 2007 change in standards appears to have less to do with energy efficiency than with the way standards affect costs of production for high-efficiency units, and possibly with the way standards influence competition among washer-producing firms (*e.g.,* see Ronnen, 1991).[49] As the scale of production of high efficiency units increased, production costs and/or markups by washer manufacturers fell, thereby increasing consumer welfare. The analysis is described in appendix 8–F of the direct final rule TSD.

DOE welcomes comments on approaches for improved assessment of the consumer welfare impacts of appliance standards.

1. Benefits and Burdens of TSLs Considered for Residential Clothes Washers

Table V–26 and Table V–27 summarize the quantitative impacts estimated for each TSL for residential clothes washers. The efficiency levels contained in each TSL are described in section V.A.

TABLE V–26—SUMMARY OF RESULTS FOR CLOTHES WASHER TRIAL STANDARD LEVELS: NATIONAL IMPACTS

Category	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5
National Energy Savings (*quads*)	1.56	1.46	2.04	2.87	3.32.
National Water Savings (trillion gal.)	1.11	1.05	3.03	5.33	6.89.
NPV of Consumer Benefits (*2010$ billion*):					
3% discount rate	20.2	18.5	31.29	41.60	50.48.
7% discount rate	8.7	7.77	13.01	16.42	19.92.
Cumulative Emissions Reduction:					
CO_2 (*million metric tons*)	87.65	81.96	112.90	155.51	178.82.
NO_X (*thousand tons*)	73.46	68.07	94.16	130.10	149.70.
Hg (*tons*)	0.198	0.226	0.269	0.364	0.413.
Value of Cumulative Emissions Reduction:					
CO_2 (*2010$ million*) *	410 to 6527	384 to 6112	530 to 8457	729 to 11613	838 to 13357.
NO_X − 3% discount rate (*2010$ million*)	22 to 224	20 to 207	28 to 286	39 to 396	44 to 456.
NO_X − 7% discount rate (*2010$ million*)	9 to 97	9 to 90	12 to 122	17 to 171	19 to 197.
Generation Capacity Reduction (*GW*) **	0.882	1.01	1.30	1.64	1.86.

Parentheses indicate negative (−) values.
* Range of the economic value of CO_2 reductions is based on estimates of the global benefit of reduced CO_2 emissions.
** Changes in 2044.

TABLE V–27—SUMMARY OF RESULTS FOR CLOTHES WASHER TRIAL STANDARD LEVELS: CONSUMER AND MANUFACTURER IMPACTS

Category	TSL 1	TSL 2	TSL 3*	TSL 4	TSL 5
Manufacturer Impacts					
Industry NPV (2010$ million)	(56.3) − (64.0)	(14.3) − (490.3)	96.4 − (858.8)	205.0 − (1,256.4)	255.5 − (1,335.3)
Industry NPV (% change)	(2.2) − (2.5)	(0.6) − (19.0)	3.7 − (33.2)	7.9 − (48.6)	9.9 − (51.6)
Consumer Mean LCC Savings (2010$)					
Top-Loading Standard Clothes Washer	268	243	268/366	491	524
Front-Loading Standard Clothes Washer	NA **	2.2	37	35	102
Top-Loading Compact Clothes Washer	159	159	159/312	312	312
Front-Loading Compact Clothes Washer	54	54	54	54	54
Consumer Median PBP (years)					
Top-Loading Standard Clothes Washer	0.4	0.7	0.4/0.9	1.8	1.9
Front-Loading Standard Clothes Washer	NA *	0.9	1.3	9.2	5.2
Top-Loading Compact Clothes Washer	0.5	0.5	0.5/2.1	2.1	2.1

[49] Uri Ronnen. Minimum quality standards, fixed costs, and competition. *RAND Journal of Economics.* Vol. 22, No. 4, Winter 1991.

TABLE V–27—SUMMARY OF RESULTS FOR CLOTHES WASHER TRIAL STANDARD LEVELS: CONSUMER AND MANUFACTURER IMPACTS—Continued

Category	TSL 1	TSL 2	TSL 3 *	TSL 4	TSL 5
Front-Loading Compact Clothes Washer	0.8	0.8	0.8	0.8	0.8
Distribution of Consumer LCC Impacts					
Top-Loading Standard Clothes Washer:					
Net Cost (%)	0.7	5.6	0.7/3.4	8.1	9.5
No Impact (%)	19.5	15.1	19.5/14.1	4.6	0.0
Net Benefit (%)	79.8	79.3	79.8/82.5	87.4	90.5
Front-Loading Standard Clothes Washer:					
Net Cost (%)	0.0	0.1	1.5	45.1	29.6
No Impact (%)	100.0	96.0	72.4	11.6	0.0
Net Benefit (%)	0.0	3.9	26.1	43.3	70.4
Top-Loading Compact Clothes Washer:					
Net Cost (%)	1.5	1.5	1.5/12.6	12.6	12.6
No Impact (%)	0.0	0.0	0.0	0.0	0.0
Net Benefit (%)	98.5	98.5	98.5/87.4	87.4	87.4
Front-Loading Compact Clothes Washer:					
Net Cost (%)	0.0	0.0	0.0	0.0	0.0
No Impact (%)	0.0	0.0	0.0	0.0	0.0
Net Benefit (%)	100.0	100.0	100.0	100.0	100.0

Parentheses indicate negative (−) values.

* For top-loading clothes washers under TSL 3, the first number for consumer impacts refers to the standard in 2015, and the second number refers to the standard in 2018.

** The standard level is the same as the baseline efficiency level, so no consumers are impacted and therefore calculation of a payback period is not applicable.

DOE first considered TSL 5, which represents the max-tech efficiency levels. TSL 5 would save 3.32 quads of energy and 6.89 trillion gallons of water, amounts DOE considers significant. Under TSL 5, the NPV of consumer benefit would be $19.92 billion, using a discount rate of 7 percent, and $50.48 billion, using a discount rate of 3 percent.

The cumulative emissions reductions at TSL 5 are 179 Mt of CO_2, 150 thousand tons of NO_X, and 0.413 ton of Hg. The estimated monetary value of the CO_2 emissions reductions at TSL 5 ranges from $838 million to $13,357 million. Total generating capacity in 2043 is estimated to decrease by 1.86 GW under TSL 5.

At TSL 5, the average LCC impact is a savings (LCC decrease) of $524 for top-loading standard clothes washers, a savings of $102 for front-loading standard clothes washers, a savings of $312 for top-loading compact clothes washers, and a savings of $54 for front-loading compact clothes washers. The median payback period is 1.9 years for top-loading standard clothes washers, 5.2 years for front-loading standard clothes washers, 2.1 years for top-loading compact clothes washers, and 0.8 years for front-loading compact clothes washers. A significant fraction of consumers, however, experience an LCC increase or net cost under TSL 5 for all product classes except front-loading compact: 9.5 percent for top-loading standard clothes washers, 30 percent for front-loading standard clothes washers, and 13 percent for top-loading compact clothes washers. In addition, because TSL 5 significantly raises the first cost of both top-loading and front-loading clothes washers, DOE is concerned some low-income consumers may be compelled to delay or forgo new purchases, using commercial coin laundries or repairing their existing clothes washers instead.

At TSL 5, the projected change in INPV ranges from an increase of $255.5 million to a decrease of $1,335.3 million. At this TSL, manufacturers would have to overhaul both their front-loading and top-loading platforms by the 2015 compliance date to meet demand. Redesigning all units to meet the current max-tech efficiency levels would require considerable capital and product conversion expenditures. DOE believes that the scope of the redesigns necessary to meet TSL 5 by 2015 also heightens concerns over supply chain and operational risk. DOE estimates that complete platform redesigns would cost the industry over $700 million in product and capital conversion costs. These costs alone represent a substantial portion of the total value of the industry. In addition, manufacturers could face a substantial impact on profitability at TSL 5. Because manufacturers earn a premium for ENERGY STAR products and additional profit for products that exceed the ENERGY STAR level, collapsing the market to one commodity product makes it unlikely that manufacturers could maintain their base-case profitability on these products after compliance with the standards is required. As a result, DOE expects that TSL 5 would yield impacts closer to the high end of the range of INPV impacts. If the high end of the range of impacts is reached, as DOE expects, TSL 5 could result in a net loss of 51.6 percent in INPV to clothes washer manufacturers.

The Secretary concludes that at TSL 5 for residential clothes washers, the benefits of energy savings, water savings, positive NPV of consumer benefits, generating capacity reductions, emission reductions, and the estimated monetary value of the CO_2 emissions reductions would be outweighed by the significant fraction of consumers that experience an increase in life-cycle cost and the impacts on manufacturers, including the conversion costs and profit margin impacts that could result in a very large reduction in INPV for the manufacturers and the risk of manufacturer capacity constraints resulting from the necessary changes by 2015. Consequently, the Secretary has concluded that TSL 5 is not economically justified.

DOE next considered TSL 4. TSL 4 would save 2.87 quads of energy and 5.33 trillion gallons of water, amounts DOE considers significant. Under TSL 4, the NPV of consumer benefit would be 16.42 billion, using a discount rate of 7 percent, and $41.60 billion, using a discount rate of 3 percent.

The cumulative emissions reductions at TSL 4 are 156 Mt of CO_2, 130 thousand tons of NO_X, and 0.364 tons of Hg. The estimated monetary value of the CO_2 emissions reductions at TSL 4 ranges from $729 million to $11,613 million. Total generating capacity in 2044 is estimated to decrease by 1.64 GW under TSL 4.

At TSL 4, the average LCC impact is a savings of $491 for top-loading standard clothes washers, a savings of $35 for front-loading standard clothes washers, a savings of $312 for top-loading compact clothes washers, and a savings of $54 for front-loading compact clothes washers. The median payback period is 1.8 years for top-loading standard clothes washers, 9.2 years for front-loading standard clothes washers, 2.1 years for top-loading compact clothes washers, and 0.8 years for front-loading compact clothes washers. A significant fraction of consumers, however, experience an LCC net cost for all product classes except front-loading compact: 8 percent for top-loading standard clothes washers, 45 percent for front-loading standard clothes washers, and 13 percent for top-loading compact clothes washers. In addition, TSL 4 significantly raises the first cost of both top-loading and front-loading clothes washers, and DOE is concerned some low-income consumers may be compelled to delay or forgo new purchases.

At TSL 4, the projected change in INPV ranges from an increase of $205.0 million to a decrease of $1,256.4 million. At this TSL, manufacturers would be required to overhaul both front-loading and top-loading platforms by the 2015 compliance date to meet demand. DOE estimates that it would cost the industry approximately $692 million in product and capital conversion costs at TSL 4. These costs reflect substantial platform changes to both top-loading and front-loading clothes washers by 2015, represent a significant portion of the total value of the industry, and trigger capacity concerns in light of the magnitude and timing of the necessary changes. In addition, manufacturers could face a substantial impact on profitability at TSL 4. Because manufacturers earn a premium for ENERGY STAR products and additional profit for products that exceed the ENERGY STAR level, collapsing the market to a few commodity products without efficiency differentiators makes it unlikely that manufactures could maintain their base-case profitability on these products after standards. Because of the effect, DOE expects that TSL 4 would yield impacts closer to the high end of the range of INPV impacts. If the high end of the range of impacts is reached, as DOE expects, TSL 4 could result in a net loss of 48.6 percent in INPV to clothes washer manufacturers.

The Secretary concludes that at TSL 4 for residential clothes washers, the benefits of energy savings, water savings, positive NPV of consumer benefits, generating capacity reductions, emission reductions, and the estimated monetary value of the CO_2 emissions reductions would be outweighed by the economic burden on a significant fraction of consumers due to the large increase in product cost and the impacts on manufacturers, including the conversion costs and profit margin impacts that could result in a very large reduction in INPV for manufacturers and the risk of manufacturer capacity constraints resulting from the necessary changes by 2015. Consequently, the Secretary has concluded that TSL 4 is not economically justified.

DOE then considered TSL 3. TSL 3 would save 2.04 quads of energy and 3.03 trillion gallons of water, amounts DOE considers significant. Under TSL 3, the NPV of consumer benefit would be $13.01 billion, using a discount rate of 7 percent, and $31.29 billion, using a discount rate of 3 percent.

The cumulative emissions reductions at TSL 3 are 113 Mt of CO_2, 94.2 thousand tons of NO_X, and 0.269 ton of Hg. The estimated monetary value of the CO_2 emissions reductions at TSL 3 ranges from $530 million to $8,457 million. Total generating capacity in 2045 is estimated to decrease by 1.30 GW under TSL 3.

At TSL 3, the average LCC impact is a savings of $268 in 2015 and $366 in 2018 for top-loading standard clothes washers, a savings of $37 for front-loading standard clothes washers, a savings of $159 in 2015 and $312 in 2018 for top-loading compact clothes washers, and a savings of $54 for front-loading compact clothes washers. The median payback period is 0.4 years in 2015 and 0.9 years in 2018 for top-loading standard clothes washers, 1.3 years for front- loading standard clothes washers, 0.5 years in 2015 and 2.1 years in 2018 for top-loading compact clothes washers, and 0.8 years for front-loading compact clothes washers. The fraction of consumers experiencing an LCC cost is small—less than 1 percent in 2015 and 3 percent in 2018 for top-loading standard clothes washers, 1.5 percent for front-loading standard clothes washers, 1.5 percent in 2015 and 13 percent in 2018 for top-loading compact clothes washers. No consumers experience a LCC cost for front-loading compact clothes washers. The much lower first cost of washers meeting TSL 3, combined with the fact that the vast majority of consumers experience either net LCC benefits or no impacts at TSL 3, mitigates DOE's concern that some low-income consumers would be compelled to delay or forgo new purchases.

At TSL 3, the projected change in INPV ranges from an increase of $96.4 million to a decrease of $858.8 million. For most manufacturers, the efficiency levels for top-loading clothes washers at TSL 3 correspond to incremental product conversion by 2015 and a platform redesign by 2018. These compliance dates mitigate capacity risk to manufacturers and their supply chains and afford manufacturers the flexibility to spread capital requirements, engineering resources, and other conversion activities over a longer period of time depending on the individual needs of each manufacturer. These factors at TSL3 mitigate DOE's concerns about manufacturers' ability to match production capacity to market demand. At TSL 3, DOE recognizes the risk of negative impacts if manufacturers' expectations concerning reduced profit margins are realized. However, the additional flexibility of the compliance dates and range of efficiency levels above TSL 3 afford manufacturers room to maintain higher value products. Therefore, DOE expects impacts to be closer to the low end of the range of impacts.

The Secretary concludes that at TSL 3 for residential clothes washers, the benefits of energy savings, water savings, positive NPV of consumer benefits, generating capacity reductions, emission reductions, the estimated monetary value of the CO_2 emissions reductions, and favorable consumer LCC savings and payback period for more than 97 percent of consumers outweigh the LCC costs for less than 3 percent of consumers and the conversion costs and profit margin impacts that could result in a reduction in INPV for manufacturers.

In addition, the efficiency levels in TSL 3 correspond to the recommended levels in the Joint Petition, which DOE believes sets forth a statement by interested persons that are fairly representative of relevant points of view (including representatives of manufacturers of covered products, States, and efficiency advocates) and contains recommendations with respect to an energy conservation standard that are in accordance with 42 U.S.C. 6295(o). Moreover, DOE has encouraged the submission of consensus agreements as a way for diverse interested parties to develop an independent and probative analysis useful in DOE standard setting and to expedite the rulemaking process. DOE also believes that the standard levels recommended in the consensus agreement may increase the likelihood for regulatory compliance, while decreasing the risk of litigation.

After considering the analysis, comments on the framework document, and the benefits and burdens of TSL 3, the Secretary concludes that this TSL will offer the maximum improvement in efficiency that is technologically feasible and economically justified, and will result in the significant conservation of energy. Therefore, DOE adopts TSL 3 for residential clothes washers. The amended energy conservation standards for residential clothes washers, which are a minimum allowable integrated modified energy factor (IMEF) and maximum allowable integrated water factor (IWF), are shown in Table V–28.

TABLE V–28—AMENDED ENERGY CONSERVATION STANDARDS FOR RESIDENTIAL CLOTHES WASHERS

Product class	Effective March 7, 2015		Effective January 1, 2018	
	Minimum IMEF*	Maximum IWF†	Minimum IMEF*	Maximum IWF†
1. Top-loading, Compact (less than 1.6 ft^3 capacity)	0.86	14.4	1.15	12.0
2. Top-loading, Standard	1.29	8.4	1.57	6.5
3. Front-loading, Compact (less than 1.6 ft^3 capacity)	1.13	8.3	N/A	
4. Front-loading, Standard	1.84	4.7	N/A	

* IMEF (integrated modified energy factor) is calculated as the clothes container capacity in cubic feet divided by the sum, expressed in kilowatt-hours (kWh), of: (1) The total weighted per-cycle hot water energy consumption; (2) the total weighted per-cycle machine electrical energy consumption; (3) the per-cycle energy consumption for removing moisture from a test load; and (4) the per-cycle standby and off mode energy consumption.

† IWF (integrated water consumption factor) is calculated as the sum, expressed in gallons per cycle, of the total weighted per-cycle water consumption for all wash cycles divided by the clothes container capacity in cubic feet.

2. Summary of Benefits and Costs (Annualized) of the Standards

The benefits and costs of today's standards can also be expressed in terms of annualized values. The annualized monetary values are the sum of (1) the annualized national economic value, expressed in 2010$, of the benefits from operating products that meet the proposed standards (consisting primarily of operating cost savings from using less energy and water, minus increases in product purchase costs, which is another way of representing consumer NPV), and (2) the monetary value of the benefits of emission reductions, including CO_2 emission reductions.[50] The value of the CO_2 reductions, otherwise known as the Social Cost of Carbon (SCC), is calculated using a range of values per metric ton of CO_2 developed by a recent interagency process.

Although combining the values of operating savings and CO_2 reductions provides a useful perspective, two issues should be considered. First, the national operating savings are domestic U.S. consumer monetary savings that occur as a result of market transactions, while the value of CO_2 reductions is based on a global value. Second, the assessments of operating cost savings and SCC are performed with different methods that use quite different time frames for analysis. The national operating cost savings is measured for the lifetime of products shipped in 2015–2044. The SCC values, on the other hand, reflect the present value of all future climate-related impacts resulting from the emission of one ton of carbon dioxide in each year. These impacts continue well beyond 2100.

Table V–29 shows the annualized values for clothes washers. Using a 7-percent discount rate for benefits and costs other than CO_2 reductions, for which DOE used a 3-percent discount rate along with the SCC series corresponding to a value of $22.3/ton in 2010, the cost of the standards for clothes washers in today's rule is $185 million per year in increased equipment costs, while the annualized benefits are $1,234 million per year in reduced equipment operating costs, $141.7 million in CO_2 reductions, and $5.4 million in reduced NO_X emissions. In this case, the net benefit amounts to $1.20 billion per year. Using a 3-percent discount rate for all benefits and costs and the SCC series corresponding to a value of $22.3/ton in 2010, the cost of the standards for clothes washers in today's rule is $212 million per year in increased equipment costs, while the benefits are $1,808 million per year in reduced operating costs, $141.7 million in CO_2 reductions, and $8.0 million in reduced NO_X emissions. In this case, the net benefit amounts to $1.75 billion per year.

[50] DOE used a two-step calculation process to convert the time-series of costs and benefits into annualized values. First, DOE calculated a present value in 2011, the year used for discounting the NPV of total consumer costs and savings, for the time-series of costs and benefits using discount rates of 3 and 7 percent for all costs and benefits except for the value of CO_2 reductions. For the latter, DOE used a range of discount rates, as shown in Table V–29. From the present value, DOE then calculated the fixed annual payment over a 30-year period that yields the same present value. The fixed annual payment is the annualized value. Although DOE calculated annualized values, this does not imply that the time-series of cost and benefits from which the annualized values were determined is a steady stream of payments.

TABLE V–29—ANNUALIZED BENEFITS AND COSTS OF AMENDED STANDARDS (TSL 3) FOR CLOTHES WASHERS SOLD IN 2015–2044

	Discount rate	Monetized (million 2010$/year)		
		Primary estimate*	Low net benefits estimate*	High net benefits estimate*
Benefits				
Operating Cost Savings	7%	1234	1101	1379.
	3%	1808	1587	2042.
CO_2 Reduction at $4.9/t**	5%	34.5	31.7	37.4.
CO_2 Reduction at $22.3/t**	3%	142	130	154.
CO_2 Reduction at $36.5/t**	2.5%	226	207	246.
CO_2 Reduction at $67.6/t**	3%	431	396	469.
NO_X Reduction at $2,537/t**	7%	5.40	5.03	5.82.
	3%	8.01	7.39	8.68.
Total †	7% plus CO_2 range	1274 to 1671	1137 to 1502	1423 to 1854.
	7%	1381	1236	1539.
	3% plus CO_2 range	1851 to 2248	1626 to 1991	2089 to 2520.
	3%	1958	1725	2205.
Costs				
Incremental Product Costs	7%	185	258	200.
	3%	212	309	230.
Total Net Benefits				
Total †	7% plus CO_2 range	1088 to 1485	880 to 1244	1223 to 1654.
	7%	1196	978	1339.
	3% plus CO_2 range	1639 to 2036	1317 to 1682	1859 to 2291.
	3%	1746	1416	1976.

* The Primary, Low Benefit, and High Benefit Estimates utilize forecasts of energy prices and housing starts from the *AEO2010* Reference case, Low Economic Growth case, and High Economic Growth case, respectively. In addition, incremental product costs reflect a declining trend using the default price trend for product prices in the Primary Estimate, constant product prices in the Low Benefits Estimate, and a high estimate of the declining price trend in the High Benefits Estimate.

** The CO_2 values represent global values (in 2010$) of the social cost of CO_2 emissions in 2010 under several scenarios. The values of $4.9, $22.3, and $36.5 per ton are the averages of SCC distributions calculated using 5%, 3%, and 2.5% discount rates, respectively. The value of $67.6 per ton represents the 95th percentile of the SCC distribution calculated using a 3% discount rate. The value for NO_X (in 2010$) is the average of the low and high values used in DOE's analysis.

† Total Benefits for both the 3% and 7% cases are derived using the SCC value calculated at a 3% discount rate, which is $22.3/ton in 2010 (in 2010$). In the rows labeled as ''7% plus CO_2 range'' and ''3% plus CO_2 range,'' the operating cost and NO_X benefits are calculated using the labeled discount rate, and those values are added to the full range of CO_2 values.

VI. Procedural Issues and Regulatory Review

A. Review Under Executive Order 12866 and Executive Order 13563

Section 1(b)(1) of Executive Order 12866, ''Regulatory Planning and Review,'' 58 FR 51735 (Oct. 4, 1993), requires each agency to identify the problem that it intends to address, including, where applicable, the failures of private markets or public institutions that warrant new agency action, as well as to assess the significance of that problem. The problems that today's standards address are as follows:

(1) There is a lack of consumer information and/or information processing capability about energy efficiency opportunities in the home appliance market.

(2) There is asymmetric information (one party to a transaction has more and better information than the other) and/or high transactions costs (costs of gathering information and effecting exchanges of goods and services).

(3) There are external benefits resulting from improved energy efficiency of residential clothes washers that are not captured by the users of such equipment. These benefits include externalities related to environmental protection and energy security that are not reflected in energy prices, such as reduced emissions of greenhouse gases.

In addition, DOE has determined that today's regulatory action is an ''economically significant regulatory action'' under section 3(f)(1) of Executive Order 12866. Accordingly, section 6(a)(3) of the Executive Order requires that DOE prepare a regulatory impact analysis (RIA) on today's rule and that the Office of Information and Regulatory Affairs (OIRA) in the Office of Management and Budget (OMB) review this rule. DOE presented to OIRA for review the draft rule and other documents prepared for this rulemaking, including the RIA, and included these documents in the rulemaking record. The assessments prepared pursuant to Executive Order 12866 can be found in the technical support document for this rulemaking at *http://www1.eere.energy.gov/buildings/appliance_standards/residential/clothes_washers.html.* They are available for public review in the Resource Room of DOE's Building Technologies Program, 950 L'Enfant Plaza SW., Suite 600, Washington, DC 20024, (202) 586–2945, between 9:00 a.m. and 4:00 p.m., Monday through Friday, except Federal holidays.

DOE has also reviewed this regulation pursuant to Executive Order 13563, issued on January 18, 2011 (76 FR 3281, Jan. 21, 2011). EO 13563 is supplemental to and explicitly reaffirms the principles, structures, and definitions governing regulatory review established in Executive Order 12866. To the extent permitted by law, agencies are required by Executive Order 13563 to: (1) Propose or adopt a regulation only upon a reasoned determination that its benefits justify its costs (recognizing that some benefits and costs are difficult to quantify); (2) tailor regulations to impose the least burden on society, consistent with obtaining regulatory objectives, taking into account, among other things, and to the extent practicable, the costs of cumulative regulations; (3) select, in choosing among alternative regulatory approaches, those approaches that maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity); (4) to the extent feasible, specify performance objectives, rather than specifying the behavior or manner of compliance that regulated entities must adopt; and (5) identify and assess available alternatives to direct regulation, including providing economic incentives to encourage the desired behavior, such as user fees or marketable permits, or providing information upon which choices can be made by the public.

We emphasize as well that Executive Order 13563 requires agencies ''to use the best available techniques to quantify anticipated present and future benefits and costs as accurately as possible.'' In its guidance, the Office of Information and Regulatory Affairs has emphasized that such techniques may include ''identifying changing future compliance costs that might result from technological innovation or anticipated behavioral changes.'' For the reasons stated in the preamble, DOE believes that today's direct final rule is consistent with these principles, including that, to the extent permitted by law, agencies adopt a regulation only upon a reasoned determination that its benefits justify its costs and select, in choosing among alternative regulatory approaches, those approaches that maximize net benefits.

B. Review Under the Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA, 5 U.S.C. 601 *et seq.*) requires preparation of an initial regulatory flexibility analysis (IRFA) for any rule that by law must be proposed for public comment, unless the agency certifies that the rule, if promulgated, will not have a significant economic impact on a substantial number of small entities. As required by Executive Order 13272, ''Proper Consideration of Small Entities in Agency Rulemaking,'' 67 FR 53461 (August 16, 2002), DOE published procedures and policies on February 19, 2003, to ensure that the potential impacts of its rules on small entities are properly considered during the rulemaking process. 68 FR 7990. DOE has made its procedures and policies available on the Office of the General Counsel's Web site (*www.gc.doe.gov*).

DOE reviewed today's direct final rule and corresponding NOPR pursuant to the RFA and the policies and procedures discussed above. Set forth below is DOE's initial regulatory flexibility analysis for the standards proposed in the NOPR, published elsewhere in today's **Federal Register**. DOE will consider any comments on the analysis or economic impacts of the rule in determining whether to proceed with the direct final rule. DOE will publish its final regulatory flexibility analysis (FRFA), including responses to any comments received, in a separate notice at the conclusion of the 110-day comment period.

1. Description of Why DOE Is Considering the Standards in Today's Direct Final Rule

The reasons why DOE is establishing the standards in today's direct final rule and the objectives of these standards are provided elsewhere in the preamble and not repeated here.

2. Statement of the Objectives of, and Legal Basis for, the Standards

A statement of the objectives of, and legal basis for, the standards in today's direct final rule is provided elsewhere in the preamble and not repeated here.

3. Description and Estimated Number of Small Entities Regulated

For manufacturers of residential clothes washers, the Small Business Administration (SBA) has set a size threshold, which defines those entities classified as ''small businesses'' for the purposes of the statute. DOE used the SBA's small business size standards to determine whether any small entities would be subject to the requirements of the rule. 65 FR 30836, 30848 (May 15, 2000), as amended at 65 FR 53533, 53544 (Sept. 5, 2000) and codified at 13 CFR part 121.The size standards are listed by North American Industry Classification System (NAICS) code and industry description and are available at *www.sba.gov/idc/groups/public/documents/sba_homepage/serv_sstd_tablepdf.pdf.* Residential clothes washer manufacturing is classified under NAICS Code 335224, ''Household Laundry Equipment Manufacturing.'' The SBA sets a threshold of 1,000 employees or less for an entity to be considered as a small business for this category.

To estimate the number of small businesses who could be impacted by the amended energy conservation standards, DOE conducted a market survey using all available public information to identify potential small manufacturers. DOE's research included the AHAM membership directory, product databases (CEE, CEC, and ENERGY STAR databases) and individual company Web sites to find potential small business manufacturers. DOE also asked interested parties and industry representatives if they were aware of any other small business manufacturers during manufacturer interviews and at previous DOE public meetings. DOE reviewed all publicly available data and contacted various companies, as necessary, to determine whether they met the SBA's definition of a small business manufacturer of covered residential clothes washers. DOE screened out companies that did not offer products covered by this rulemaking, did not meet the definition of a ''small business,'' or are foreign owned and operated.

The majority of residential clothes washers are currently manufactured in the United States by one corporation that accounts for approximately 64 percent of the total market. Together, this manufacturer and three other manufacturers that do not meet the definition of a small business manufacturer comprise 92 percent of the residential clothes washer market. The small portion of the remaining residential clothes washer market (approximately 700,000 shipments) is supplied by a combination of 12 international and domestic companies, all of which have small market shares. Of the remaining 12 companies that manufacturer residential clothes washers for sale in the United States, DOE identified only one manufacturer that is considered a small business under NAICS Code 335224.

4. Description and Estimate of Compliance Requirements

The one small business manufacturer of residential clothes washers covered by this rulemaking has one product platform. It makes a top-loading standard residential clothes washer that currently meets a 1.85 MEF and a 6.75 WF. The product meets the 2015 energy conservation standards proposed in this direct final rule, but falls short of the 2018 standard. The unit does not offer warm rinse and has electromechanical controls, making it likely that three wash temperatures (hot, warm, cold) are available on all settings including Normal for test procedure purposes. Thus, it is likely the unit will have to undergo alterations to its basic design to meet the 2018 efficiency requirements.

This company appears to manufacture its residential clothes washer with less automation and more labor than some of the larger competitors. To change the design of their current product to meet the 2018 efficiency standards, one available design pathway would be increasing the volume of the wash basket, assuming there is enough clearance within the cabinet. Increasing the drum's radius would involve cutting slightly larger octagonal pieces of metal and would not be a capital intensive solution. With this pathway, the assembly process and fabrication time would essentially remain the same. This solution would also prevent the small business manufacturer from bearing the cost of retrofitting their manufacturing process and could result in lower per-unit conversion costs relative to larger manufacturers.

Based on the engineering analysis and manufacturer interviews, if two full-time engineers took one year to implement a larger drum radius within the existing cabinet it could cost the manufacturer roughly $200,000 to implement the design change for the 2018 compliance date. If the manufacturer were to incur additional tooling costs to implement this change, this could lead to an additional $200,000 in capital conversion costs. Because the small business manufacturer already meets the 2015 energy conservation standards, it would have 7 years from the announcement of today's direct final rule until it would have to make any changes to its current product in response to standards.

5. Duplication, Overlap, and Conflict With Other Rules

DOE is not aware of any rules or regulations that duplicate, overlap, or conflict with the rule being promulgated today.

6. Significant Alternatives to the Rule

The discussion above analyzes impacts on small businesses that would result from DOE's rule. In addition to the other TSLs being considered, the direct final rule TSD includes a regulatory impact analysis (RIA). For residential clothes washers, the RIA discusses the following policy alternatives: (1) No new regulatory action; (2) consumer rebates; (3) consumer tax credits; (4) manufacturer tax credits; (5) voluntary energy efficiency targets; (6) early replacement; and (7) bulk government purchases. While these alternatives may mitigate to some varying extent the economic impacts on small entities compared to the amended standards, DOE determined that the energy savings of these regulatory alternatives are at least 3.8 times smaller than those that would be expected to result from adoption of the amended standard levels. Thus, DOE rejected these alternatives and is adopting the amended standards set forth in this rulemaking. (See chapter 17 of direct final rule TSD for further detail on the policy alternatives DOE considered.)

C. Review Under the Paperwork Reduction Act

Manufacturers of residential clothes washers must certify to DOE that their products comply with any applicable energy conservation standard. In certifying compliance, manufacturers must test their products according to the DOE test procedures for residential clothes washers, including any amendments adopted for those test procedures. DOE has established regulations for the certification and recordkeeping requirements for all covered consumer products and commercial equipment, including residential clothes washers. 76 FR 12422 (March 7, 2011). The collection-of-information requirement for the certification and recordkeeping is subject to review and approval by OMB under the Paperwork Reduction Act (PRA). This requirement has been approved by OMB under OMB control number 1910–1400. Public reporting burden for the certification is estimated to average 20 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information.

Notwithstanding any other provision of the law, no person is required to respond to, nor shall any person be subject to a penalty for failure to comply with, a collection of information subject to the requirements of the PRA, unless that collection of information displays a currently valid OMB Control Number.

D. Review Under the National Environmental Policy Act of 1969

Pursuant to the National Environmental Policy Act (NEPA) of 1969, DOE has determined that today's rule fits within the category of actions included in Categorical Exclusion (CX) B5.1 and otherwise meets the requirements for application of a CX. *See* 10 CFR Part 1021, App. B, B5.1(b); 1021.410(b) and Appendix B, B(1)–(5). The rule fits within the category of actions because it is a rulemaking that establishes energy conservation standards for consumer products or industrial equipment, and for which none of the exceptions identified in CX B5.1(b) apply. Therefore, DOE has made a CX determination for this rulemaking, and DOE does not need to prepare an Environmental Assessment or Environmental Impact Statement for this rule. DOE's CX determination for this direct final rule is available at *http://cxnepa.energy.gov.*

E. Review Under Executive Order 13132

Executive Order 13132, ''Federalism.'' 64 FR 43255 (Aug. 10, 1999) imposes certain requirements on Federal agencies formulating and implementing policies or regulations that preempt State law or that have Federalism implications. The Executive Order requires agencies to examine the constitutional and statutory authority supporting any action that would limit the policymaking discretion of the States and to carefully assess the necessity for such actions. The Executive Order also requires agencies to have an accountable process to ensure meaningful and timely input by State and local officials in the development of regulatory policies that have Federalism implications. On March 14, 2000, DOE published a statement of policy describing the intergovernmental consultation process it will follow in the development of such regulations. 65 FR 13735. EPCA governs and prescribes Federal preemption of State regulations as to energy conservation for the products that are the subject of today's direct final rule. States can petition DOE for exemption from such preemption to the extent, and based on criteria, set forth in EPCA. (42 U.S.C. 6297) No further action is required by Executive Order 13132.

F. Review Under Executive Order 12988

With respect to the review of existing regulations and the promulgation of new regulations, section 3(a) of Executive Order 12988, ''Civil Justice Reform,'' imposes on Federal agencies the general duty to adhere to the following requirements: (1) Eliminate drafting errors and ambiguity; (2) write regulations to minimize litigation; and (3) provide a clear legal standard for affected conduct rather than a general standard and promote simplification and burden reduction. 61 FR 4729 (Feb. 7, 1996). Section 3(b) of Executive Order 12988 specifically requires that Executive agencies make every reasonable effort to ensure that the regulation: (1) Clearly specifies the preemptive effect, if any; (2) clearly specifies any effect on existing Federal law or regulation; (3) provides a clear legal standard for affected conduct while promoting simplification and burden reduction; (4) specifies the retroactive effect, if any; (5) adequately defines key terms; and (6) addresses other important issues affecting clarity and general draftsmanship under any guidelines issued by the Attorney General. Section 3(c) of Executive Order 12988 requires Executive agencies to review regulations in light of applicable standards in section 3(a) and section 3(b) to determine whether they are met or it is unreasonable to meet one or more of them. DOE has completed the required review and determined that, to the extent permitted by law, this direct final rule meets the relevant standards of Executive Order 12988.

G. Review Under the Unfunded Mandates Reform Act of 1995

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA) requires each Federal agency to assess the effects of Federal regulatory actions on State, local, and Tribal governments and the private sector. Public Law 104–4, sec. 201 (codified at 2 U.S.C. 1531). For an amended regulatory action likely to result in a rule that may cause the expenditure by State, local, and Tribal governments, in the aggregate, or by the private sector of $100 million or more in any one year (adjusted annually for inflation), section 202 of UMRA requires a Federal agency to publish a written statement that estimates the resulting costs, benefits, and other effects on the national economy. (2 U.S.C. 1532(a), (b)) The UMRA also requires a Federal agency to develop an effective process to permit timely input by elected officers of State, local, and Tribal governments on a ''significant intergovernmental mandate,'' and requires an agency plan for giving notice and opportunity for timely input to potentially affected small governments before establishing any requirements that might significantly or uniquely affect small governments. On March 18, 1997, DOE published a statement of policy on its process for intergovernmental consultation under UMRA. 62 FR 12820. DOE's policy statement is also available at *http://www.gc.doe.gov/*.

DOE has concluded that this direct final rule would likely result in a final rule that could impose expenditures of $100 million or more on the private sector. Such expenditures may include: (1) Investment in research and development and in capital expenditures by residential clothes washer manufacturers in the years between the final rule and the compliance date for the new standards, and (2) incremental additional expenditures by consumers to purchase higher-efficiency residential clothes washers.

Section 202 of UMRA authorizes a Federal agency to respond to the content requirements of UMRA in any other statement or analysis that accompanies the final rule. 2 U.S.C. 1532(c). The content requirements of section 202(b) of UMRA relevant to a private sector mandate substantially overlap the economic analysis requirements that apply under section 325(o) of EPCA and Executive Order 12866. The **SUPPLEMENTARY INFORMATION** section of the notice of final rulemaking and the ''Regulatory Impact Analysis'' section of the TSD for this direct final rule respond to those requirements.

Under section 205 of UMRA, the Department is obligated to identify and consider a reasonable number of regulatory alternatives before promulgating a rule for which a written statement under section 202 is required. 2 U.S.C. 1535(a). DOE is required to select from those alternatives the most cost-effective and least burdensome alternative that achieves the objectives of the rule unless DOE publishes an explanation for doing otherwise, or the selection of such an alternative is inconsistent with law. As required by 42 U.S.C. 6295(d), (f), and (o), 6313(e), and 6316(a), today's final rule would establish energy conservation standards for residential clothes washers that are designed to achieve the maximum improvement in energy efficiency that DOE has determined to be both technologically feasible and economically justified. A full discussion of the alternatives considered by DOE is presented in the ''Regulatory Impact Analysis'' section of the TSD for today's direct final rule.

H. Review Under the Treasury and General Government Appropriations Act, 1999

Section 654 of the Treasury and General Government Appropriations Act, 1999 (Pub. L. 105–277) requires Federal agencies to issue a Family Policymaking Assessment for any rule that may affect family well-being. This rule would not have any impact on the autonomy or integrity of the family as an institution. Accordingly, DOE has concluded that it is not necessary to prepare a Family Policymaking Assessment.

I. Review Under Executive Order 12630

DOE has determined, under Executive Order 12630, ''Governmental Actions and Interference with Constitutionally Protected Property Rights'' 53 FR 8859 (March 18, 1988), that this regulation would not result in any takings that might require compensation under the Fifth Amendment to the U.S. Constitution.

J. Review Under the Treasury and General Government Appropriations Act, 2001

Section 515 of the Treasury and General Government Appropriations Act, 2001 (44 U.S.C. 3516, note) provides for Federal agencies to review most disseminations of information to the public under guidelines established by each agency pursuant to general guidelines issued by OMB. OMB's guidelines were published at 67 FR 8452 (Feb. 22, 2002), and DOE's guidelines were published at 67 FR 62446 (Oct. 7, 2002). DOE has reviewed today's direct final rule under the OMB and DOE guidelines and has concluded that it is consistent with applicable policies in those guidelines.

K. Review Under Executive Order 13211

Executive Order 13211, ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'' 66 FR 28355 (May 22, 2001), requires Federal agencies to prepare and submit to OIRA at OMB, a Statement of Energy Effects for any significant energy action. A ''significant energy action'' is defined as any action by an agency that promulgates or is expected to lead to promulgation of a final rule, and that: (1) Is a significant regulatory action under Executive Order 12866, or any successor order; and (2) is likely to have a significant adverse effect on the supply, distribution, or use of energy, or (3) is designated by the Administrator of OIRA as a significant energy action. For any significant energy action, the agency must give a detailed statement of any adverse effects on energy supply, distribution, or use should the proposal be implemented, and of reasonable alternatives to the action and their expected benefits on energy supply, distribution, and use.

DOE has concluded that today's regulatory action, which sets forth energy conservation standards for residential clothes washers, is not a significant energy action because the amended standards are not likely to have a significant adverse effect on the supply, distribution, or use of energy, nor has it been designated as such by the Administrator at OIRA. Accordingly, DOE has not prepared a Statement of Energy Effects on the direct final rule.

L. Review Under the Information Quality Bulletin for Peer Review

On December 16, 2004, OMB, in consultation with the Office of Science and Technology Policy (OSTP), issued its Final Information Quality Bulletin for Peer Review (the Bulletin). 70 FR 2664 (Jan. 14, 2005). The Bulletin establishes that certain scientific information shall be peer reviewed by qualified specialists before it is disseminated by the Federal Government, including influential scientific information related to agency regulatory actions. The purpose of the bulletin is to enhance the quality and credibility of the Government's scientific information. Under the Bulletin, the energy conservation standards rulemaking analyses are ''influential scientific information,'' which the Bulletin defines as ''scientific information the agency reasonably can determine will have or does have a clear and substantial impact on important public policies or private sector decisions.'' 70 FR 2667.

In response to OMB's Bulletin, DOE conducted formal in-progress peer reviews of the energy conservation standards development process and analyses and has prepared a Peer Review Report pertaining to the energy conservation standards rulemaking analyses. Generation of this report involved a rigorous, formal, and documented evaluation using objective criteria and qualified and independent reviewers to make a judgment as to the technical/scientific/business merit, the actual or anticipated results, and the productivity and management effectiveness of programs and/or projects. The ''Energy Conservation Standards Rulemaking Peer Review Report'' dated February 2007 has been disseminated and is available at the following Web site: *www1.eere.energy.gov/buildings/appliance_standards/peer_review.html.*

M. Congressional Notification

As required by 5 U.S.C. 801, DOE will report to Congress on the promulgation of this rule prior to its effective date. The report will state that it has been determined that the rule is a ''major rule'' as defined by 5 U.S.C. 804(2).

VII. Approval of the Office of the Secretary

The Secretary of Energy has approved publication of today's direct final rule.

List of Subjects

10 CFR Part 429

Administrative practice and procedure, Confidential business information, Energy conservation, Household appliances, and Reporting and recordkeeping requirements.

10 CFR Part 430

Administrative practice and procedure, Confidential business information, Energy conservation, Household appliances, Imports, Intergovernmental relations, and Small businesses.

Issued in Washington, DC, on May 11, 2012.

Dr. David Danielson,

Assistant Secretary, Energy Efficiency and Renewable Energy.

For the reasons set forth in the preamble, DOE amends parts 429 and 430 of title 10 of the Code of Federal Regulations, as set forth below:

PART 429—CERTIFICATION, COMPLIANCE, AND ENFORCEMENT FOR CONSUMER PRODUCTS AND COMMERCIAL AND INDUSTRIAL EQUIPMENT

■ 1. The authority citation for part 429 continues to read as follows:

Authority: 42 U.S.C. 6291–6317.

■ 2. In § 429.20 revise paragraph (b)(2) to read as follows:

§ 429.20 Residential clothes washers.

* * * * *

(b) * * *

(2) Pursuant to § 429.12(b)(13), a certification report shall include the following public product-specific information:

(i) For residential clothes washers manufactured before March 7, 2015: The modified energy factor (MEF) in cubic feet per kilowatt hour per cycle (cu ft/kWh/cycle) and the capacity in cubic feet (cu ft). For standard-size residential clothes washers, a water factor (WF) in gallons per cycle per cubic feet (gal/cycle/cu ft).

(ii) For residential clothes washers manufactured on or after March 7, 2015: The integrated modified energy factor (IMEF) in cu ft/kWh/cycle, the integrated water factor (IWF) in gal/cycle/cu ft, the capacity in cu ft and the type of loading (top-loading or front-loading).

* * * * *

PART 430—ENERGY CONSERVATION PROGRAM FOR CONSUMER PRODUCTS

■ 3. The authority citation for part 430 continues to read as follows:

Authority: 42 U.S.C. 6291–6309; 28 U.S.C. 2461 note.

■ 4. In § 430.32 revise paragraph (g) to read as follows:

§ 430.32 Energy and water conservation standards and their effective dates.

* * * * *

(g) *Clothes washers.* (1) Clothes washers manufactured on or after January 1, 2007 shall have a Modified Energy Factor no less than:

Product class	Modified energy factor (cu.ft./kWh/cycle)
i. Top-loading, Compact (less than 1.6 ft^3 capacity)	0.65.
ii. Top-loading, Standard (1.6 ft^3 or greater capacity)	1.26.
iii. Top-Loading, Semi-Automatic	Not Applicable.[1]
iv. Front-loading	1.26.
v. Suds-saving	Not Applicable.[1]

[1] Must have an unheated rinse water option.

(2) All top-loading or front-loading standard-size residential clothes washers manufactured on or after January 1, 2011, and before March 7, 2015, shall meet the following standard—

(i) A Modified Energy Factor of at least 1.26; and

(ii) A Water Factor of not more than 9.5.

(3) Clothes washers manufactured on or after March 7, 2015, and before January 1, 2018, shall have an Integrated Modified Energy Factor no less than, and an Integrated Water Factor no greater than:

Product class	Integrated modified energy factor (cu.ft./kWh/cycle)	Integrated water factor (gal/cycle/cu.ft.)
i. Top-loading, Compact (less than 1.6 ft^3 capacity)	0.86	14.4
ii. Top-loading, Standard (1.6 ft^3 or greater capacity)	1.29	8.4
iii. Front-loading, Compact (less than 1.6 ft^3 capacity)	1.13	8.3
iv. Front-loading, Standard (1.6 ft^3 or greater capacity)	1.84	4.7

(4) Clothes washers manufactured on or after January 1, 2018 shall have an Integrated Modified Energy Factor no less than, and an Integrated Water Factor no greater than:

Product class	Integrated modified energy factor (cu.ft./kWh/cycle)	Integrated water factor (gal/cycle/cu.ft.)
i. Top-loading, Compact (less than 1.6 ft^3 capacity)	1.15	12.0
ii. Top-loading, Standard (1.6 ft^3 or greater capacity)	1.57	6.5
iii. Front-loading, Compact (less than 1.6 ft^3 capacity)	1.13	8.3
iv. Front-loading, Standard (1.6 ft^3 or greater capacity)	1.84	4.7

* * * * *

[FR Doc. 2012–12320 Filed 5–30–12; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

10 CFR Parts 429 and 430

[Docket Number EERE–2008–BT–STD–0019]

RIN 1904–AB90

Energy Conservation Program: Energy Conservation Standards for Residential Clothes Washers

AGENCY: Office of Energy Efficiency and Renewable Energy, Department of Energy.

ACTION: Proposed rule.

SUMMARY: The Energy Policy and Conservation Act of 1975 (EPCA), as amended, prescribes energy conservation standards for various consumer products and certain commercial and industrial equipment, including residential clothes washers. EPCA also requires the U.S. Department of Energy (DOE) to determine whether amended standards would be technologically feasible and economically justified, and would save a significant amount of energy. In this proposed rule, DOE proposes amended energy conservation standards for residential clothes washers identical to those set forth in a direct final rule published elsewhere in today's **Federal Register**. If DOE receives adverse comment and determines that such comment may provide a reasonable basis for withdrawing the direct final rule, DOE will publish a notice withdrawing the final rule and will proceed with this proposed rule.

DATES: DOE will accept comments, data, and information regarding the proposed standards no later than September 18, 2012.

ADDRESSES: See section III, ''Public Participation,'' for details.

Any comments submitted must identify the proposed rule for Energy Conservation Standards for Residential Clothes Washers, and provide docket number EERE–2008–BT–STD–0019 and/or regulatory information number (RIN) number 1904–AB90. Comments may be submitted using any of the following methods:

1. *Federal eRulemaking Portal: www.regulations.gov.* Follow the instructions for submitting comments.

2. *Email: RCW–2008–STD–0019@ee.doe.gov.* Include the docket number and/or RIN in the subject line of the message.

3. *Mail:* Ms. Brenda Edwards, U.S. Department of Energy, Building Technologies Program, Mailstop EE–2J, 1000 Independence Avenue SW., Washington, DC 20585–0121. If possible, please submit all items on a CD. It is not necessary to include printed copies.

4. *Hand Delivery/Courier:* Ms. Brenda Edwards, U.S. Department of Energy, Building Technologies Program, 950 L'Enfant Plaza SW., Suite 600, Washington, DC 20024. Telephone: (202) 586–2945. If possible, please submit all items on a CD. It is not necessary to include printed copies.

Docket: The docket is available for review at *regulations.gov,* including **Federal Register** notices, framework documents, public meeting attendee lists and transcripts, comments, and other supporting documents/materials.

A link to the docket web page can be found at: *www.regulations.gov/#!docketDetail;D=EERE-2008-BT-STD-0019.*

For further information on how to submit or review public comments or view hard copies of the docket in the Resource Room, contact Ms. Brenda Edwards at (202) 586–2945 or email: *Brenda.Edwards@ee.doe.gov.*

FOR FURTHER INFORMATION CONTACT:

Stephen L. Witkowski, U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, Building Technologies Program, EE–2J, 1000 Independence Avenue SW., Washington, DC 20585–0121, (202) 586–7463, email: *stephen.witkowski@ee.doe.gov.*

Ms. Elizabeth Kohl, U.S. Department of Energy, Office of General Counsel, GC–71, 1000 Independence Avenue SW., Washington, DC 20585–0121, (202) 586–7796, email: *Elizabeth.Kohl@hq.doe.gov.*

SUPPLEMENTARY INFORMATION:

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I. Introduction and Legal Authority

Title III, Part B of the Energy Policy and Conservation Act of 1975 (EPCA or the Act), Public Law 94–163 (42 U.S.C. 6291–6309, as codified) established the Energy Conservation Program for Consumer Products Other Than Automobiles,[1] a program covering most major household appliances (collectively referred to as ''covered products''), which includes the residential clothes washers that are the subject of this rulemaking. (42 U.S.C. 6292(a)(7)) EPCA, as amended by the Energy Information and Security Act of 2007 (EISA 2007; Pub. L. 110–140), prescribed the current energy conservation standards for residential clothes washers (42 U.S.C. 6295(g)(9), and directed DOE to publish a final rule no later than December 31, 2011, to determine whether to amend the standards in effect for clothes washers manufactured on or after January 1, 2015. (42 U.S.C. 6295(g)(9)(B)(i))

EISA 2007 also amended EPCA, in relevant part, to grant DOE authority DOE to issue a final rule (hereinafter referred to as a ''direct final rule'') establishing an energy conservation standard for a covered product on receipt of a statement submitted jointly by interested persons that are fairly representative of relevant points of view (including representatives of manufacturers of covered products, States, and efficiency advocates) as determined by the Secretary, that contains recommendations with respect to an energy conservation standard that are in accordance with the provisions of 42 U.S.C. 6295(o). EPCA also requires that a notice of proposed rulemaking (NOPR) that proposes an identical energy conservation standard be published simultaneously with the direct final rule, and DOE must provide a public comment period of at least 110 days on this proposal. (42 U.S.C. 6295(p)(4)) Not later than 120 days after issuance of the direct final rule, if one or more adverse comments or an alternative joint recommendation are received relating to the direct final rule, the Secretary must determine whether the comments or alternative recommendation may provide a reasonable basis for withdrawal under 42 U.S.C. 6295(o) or other applicable law. If the Secretary makes such a determination, DOE must withdraw the direct final rule and proceed with the simultaneously published notice of proposed rulemaking. DOE must also publish in the **Federal Register** the reason why the direct final rule was withdrawn. *Id.*

On July 30, 2010, DOE received the ''Agreement on Minimum Federal Efficiency Standards, Smart Appliances, Federal Incentives and Related Matters for Specified Appliances'' (hereinafter, the ''Joint Petition''),[2] a comment submitted by groups representing manufacturers (the Association of Home

[1] For editorial reasons, upon codification in the U.S. Code, Part B was redesignated Part A.

[2] DOE Docket No. EERE–2008–BT–STD–0019, Comment 32.

Appliance Manufacturers (AHAM), Whirlpool Corporation (Whirlpool), General Electric Company (GE), Electrolux, LG Electronics, Inc. (LG), BSH Home Appliances (BSH), Alliance Laundry Systems (ALS), Viking Range, Sub-Zero Wolf, Friedrich A/C, U-Line, Samsung, Sharp Electronics, Miele, Heat Controller, AGA Marvel, Brown Stove, Haier, Fagor America, Airwell Group, Arcelik, Fisher & Paykel, Scotsman Ice, Indesit, Kuppersbusch, Kelon, and DeLonghi); energy and environmental advocates (American Council for an Energy Efficient Economy (ACEEE), Appliance Standards Awareness Project (ASAP), Natural Resources Defense Council (NRDC), Alliance to Save Energy (ASE), Alliance for Water Efficiency (AWE), Northwest Power and Conservation Council (NPCC), and Northeast Energy Efficiency Partnerships (NEEP)); and consumer groups (Consumer Federation of America (CFA) and the National Consumer Law Center (NCLC)) (collectively, the ''Joint Petitioners''). The Joint Petitioners recommended specific energy conservation standards for residential clothes washers that they believed would satisfy the EPCA requirements in 42 U.S.C. 6295(o). Earthjustice submitted a comment affirming its support for the joint petition.[3]

DOE has considered the recommended energy conservation standards and believes that they meet the EPCA requirements for issuance of a direct final rule. As a result, DOE has published a direct final rule establishing energy conservation standards for clothes washers elsewhere in today's **Federal Register**. If DOE receives adverse comments that may provide a reasonable basis for withdrawal and withdraws the direct final rule, DOE will consider those comments and any other comments received in determining how to proceed with today's proposed rule.

For further background information on these proposed standards and the supporting analyses, please see the direct final rule published elsewhere in today's **Federal Register**. That document includes additional discussion on the EPCA requirements for promulgation of energy conservation standards, the current standards for residential clothes washers, and the history of the standards rulemakings establishing such standards, as well as information on the test procedures used to measure the energy efficiency of clothes washers. The document also contains an in-depth discussion of the analyses conducted in support of this rulemaking, the methodologies DOE used in conducting those analyses, and the analytical results.

II. Proposed Standards

When considering proposed standards, the new or amended energy conservation standard that DOE adopts for any type (or class) of covered product shall be designed to achieve the maximum improvement in energy efficiency that DOE determines is technologically feasible and economically justified. (42 U.S.C. 6295(o)(2)(A)) In determining whether a standard is economically justified, DOE must determine whether the benefits of the standard exceed its burdens to the greatest extent practicable, in light of the seven statutory factors set forth in EPCA. (42 U.S.C. 6295(o)(2)(B)(i)) The new or amended standard must also result in a significant conservation of energy. (42 U.S.C. 6295(o)(3)(B))

The Department considered the impacts of standards at each trial standard level (TSL) considered by DOE, beginning with maximum technologically feasible level, to determine whether that level was economically justified. Where the max-tech level was not economically justified, DOE then considered the next most efficient level and undertook the same evaluation until it reached the highest efficiency level that is both technologically feasible and economically justified and saves a significant amount of energy.

To aid the reader as DOE discusses the benefits and burdens of each TSL, DOE has included tables that present a summary of the results of DOE's quantitative analysis for each TSL. In addition to the quantitative results presented in the tables, DOE also considers other burdens and benefits that affect economic justification. These include the impacts on identifiable subgroups of consumers, such as low-income households and seniors, who may be disproportionately affected by a national standard. Section V.B.1 of the direct final rule published elsewhere in today's **Federal Register** presents the estimated impacts of each TSL for these subgroups.

A. Benefits and Burdens of TSLs Considered for Clothes Washers

Table II.1 and Table II.2 present a summary of the quantitative impacts estimated for each TSL for clothes washers. The efficiency levels contained in each TSL are described in section V.A of the direct final rule.

TABLE II.1—SUMMARY OF RESULTS FOR CLOTHES WASHER TRIAL STANDARD LEVELS: NATIONAL IMPACTS

Category	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5
National Energy Savings (*quads*)	1.56	1.46	2.04	2.87	3.32.
National Water Savings (*trillion gal.*)	1.11	1.05	3.03	5.33	6.89.
NPV of Consumer Benefits (*2010$ billion*)					
3% discount rate	20.2	18.5	31.29	41.60	50.48.
7% discount rate	8.7	7.77	13.01	16.42	19.92.
Cumulative Emissions Reduction					
CO_2 (*million metric tons*)	87.65	81.96	112.90	155.51	178.82.
NO_X (*thousand tons*)	73.46	68.07	94.16	130.10	149.70.
Hg (*tons*)	0.198	0.226	0.269	0.364	0.413.
Value of Cumulative Emissions Reduction					
CO_2 (*2010$ million*)*	410 to 6527	384 to 6112	530 to 8457	729 to 11613	838 to 13357.
NO_X—3% discount rate (*2010$ million*)	22 to 224	20 to 207	28 to 286	39 to 396	44 to 456.
NO_X—7% discount rate (*2010$ million*)	9 to 97	9 to 90	12 to 122	17 to 171	19 to 197.
Generation Capacity Reduction (*GW*)**	0.882	1.01	1.30	1.64	1.86.

Parentheses indicate negative (−) values.
* Range of the economic value of CO_2 reductions is based on estimates of the global benefit of reduced CO_2 emissions.
** Changes in 2044.

[3] DOE Docket No. EERE–2008–BT–STD–0019, Comment 38.

TABLE II.2—SUMMARY OF RESULTS FOR CLOTHES WASHER TRIAL STANDARD LEVELS: CONSUMER AND MANUFACTURER IMPACTS

Category	TSL 1	TSL 2	TSL 3*	TSL 4	TSL 5
Manufacturer Impacts					
Industry NPV (2010$ million)	(56.3)–(64.0)	(14.3)–(490.3)	96.4–(858.8)	205.0–(1,256.4)	255.5–(1,335.3)
Industry NPV (% change)	(2.2)–(2.5)	(0.6)–(19.0)	3.7–(33.2)	7.9–(48.6)	9.9–(51.6)
Consumer Mean LCC Savings (2010$)					
Top-Loading Standard Clothes Washer	268	243	268/366	491	524
Front-Loading Standard Clothes Washer	**NA	2.2	37	35	102
Top-Loading Compact Clothes Washer	159	159	159/312	312	312
Front-Loading Compact Clothes Washer	54	54	54	54	54
Consumer Median PBP (years)					
Top-Loading Standard Clothes Washer	0.4	0.7	0.4/0.9	1.8	1.9
Front-Loading Standard Clothes Washer	**NA	0.9	1.3	9.2	5.2
Top-Loading Compact Clothes Washer	0.5	0.5	0.5/2.1	2.1	2.1
Front-Loading Compact Clothes Washer	0.8	0.8	0.8	0.8	0.8
Distribution of Consumer LCC Impacts					
Top-Loading Standard Clothes Washer					
Net Cost (%)	0.7	5.6	0.7/3.4	8.1	9.5
No Impact (%)	19.5	15.1	19.5/14.1	4.6	0.0
Net Benefit (%)	79.8	79.3	79.8/82.5	87.4	90.5
Front-Loading Standard Clothes Washer					
Net Cost (%)	0.0	0.1	1.5	45.1	29.6
No Impact (%)	100.0	96.0	72.4	11.6	0.0
Net Benefit (%)	0.0	3.9	26.1	43.3	70.4
Top-Loading Compact Clothes Washer					
Net Cost (%)	1.5	1.5	1.5/12.6	12.6	12.6
No Impact (%)	0.0	0.0	0.0	0.0	0.0
Net Benefit (%)	98.5	98.5	98.5/87.4	87.4	87.4
Front-Loading Compact Clothes Washer					
Net Cost (%)	0.0	0.0	0.0	0.0	0.0
No Impact (%)	0.0	0.0	0.0	0.0	0.0
Net Benefit (%)	100.0	100.0	100.0	100.0	100.0

Parentheses indicate negative (−) values.
* For top-loading clothes washers under TSL 3, the first number for consumer impacts refers to the standard in 2015, and the second number refers to the standard in 2018.
** The standard level is the same as the baseline efficiency level, so no consumers are impacted and therefore calculation of a payback period is not applicable.

DOE first considered TSL 5, which represents the max-tech efficiency levels. TSL 5 would save 3.32 quads of energy and 6.89 trillion gallons of water, amounts DOE considers significant. Under TSL 5, the NPV of consumer benefit would be $19.92 billion, using a discount rate of 7 percent, and $50.48 billion, using a discount rate of 3 percent.

The cumulative emissions reductions at TSL 5 are 179 Mt of CO_2, 150 thousand tons of NO_X, and 0.413 ton of Hg. The estimated monetary value of the CO_2 emissions reductions at TSL 5 ranges from $838 million to $13,357 million. Total generating capacity in 2043 is estimated to decrease by 1.86 GW under TSL 5.

At TSL 5, the average LCC impact is a savings (LCC decrease) of $524 for top-loading standard clothes washers, a savings of $102 for front-loading standard clothes washers, a savings of $312 for top-loading compact clothes washers, and a savings of $54 for front-loading compact clothes washers. The median payback period is 1.9 years for top-loading standard clothes washers, 5.2 years for front-loading standard clothes washers, 2.1 years for top-loading compact clothes washers, and 0.8 years for front-loading compact clothes washers. A significant fraction of consumers, however, experience an LCC increase or net cost under TSL 5 for all product classes except front-loading compact: 9.5 percent for top-loading standard clothes washers, 30 percent for front-loading standard clothes washers, and 13 percent for top-loading compact clothes washers. In addition, because TSL 5 significantly raises the first cost of both top-loading and front-loading clothes washers, DOE is concerned some low-income consumers may be compelled to delay or forgo new purchases, using commercial coin laundries or repairing their existing clothes washers instead.

At TSL 5, the projected change in INPV ranges from an increase of $255.5 million to a decrease of $1,335.3 million. At this TSL, manufacturers would have to overhaul both their front-loading and top-loading platforms by the 2015 compliance date to meet demand. Redesigning all units to meet the current max-tech efficiency levels would require considerable capital and product conversion expenditures. DOE believes that the scope of the redesigns necessary to meet TSL 5 by 2015 also heightens concerns over supply chain and operational risk. DOE estimates that complete platform redesigns would cost the industry over $700 million in product and capital conversion costs. These costs alone represent a substantial portion of the total value of the industry. In addition, manufacturers could face a substantial impact on profitability at TSL 5. Because manufacturers earn a premium for ENERGY STAR products and additional profit for products that exceed the ENERGY STAR level, collapsing the market to one commodity product makes it unlikely that manufacturers could maintain their base-case profitability on these products after compliance with the standards is required. As a result, DOE expects that TSL 5 would yield impacts closer to the high end of the range of INPV impacts. If the high end of the range of impacts is reached, as DOE expects, TSL 5 could result in a net loss of 51.6 percent in INPV to clothes washer manufacturers.

The Secretary concludes that at TSL 5 for residential clothes washers, the benefits of energy savings, water savings, positive NPV of consumer benefits, generating capacity reductions, emission reductions, and the estimated monetary value of the CO_2 emissions reductions would be outweighed by the significant fraction of consumers that experience an increase in life-cycle cost and the impacts on manufacturers, including the conversion costs and profit margin impacts that could result in a very large reduction in INPV for the manufacturers and the risk of manufacturer capacity constraints resulting from the necessary changes by 2015. Consequently, the Secretary has concluded that TSL 5 is not economically justified.

DOE next considered TSL 4. TSL 4 would save 2.87 quads of energy and 5.33 trillion gallons of water, amounts DOE considers significant. Under TSL 4, the NPV of consumer benefit would be 16.42 billion, using a discount rate of 7 percent, and $41.60 billion, using a discount rate of 3 percent.

The cumulative emissions reductions at TSL 4 are 156 Mt of CO_2, 130 thousand tons of NO_X, and 0.364 tons of Hg. The estimated monetary value of the CO_2 emissions reductions at TSL 4 ranges from $729 million to $11,613 million. Total generating capacity in 2044 is estimated to decrease by 1.64 GW under TSL 4.

At TSL 4, the average LCC impact is a savings of $491 for top-loading standard clothes washers, a savings of $35 for front-loading standard clothes washers, a savings of $312 for top-loading compact clothes washers, and a savings of $54 for front-loading compact clothes washers. The median payback period is 1.8 years for top-loading standard clothes washers, 9.2 years for front-loading standard clothes washers, 2.1 years for top-loading compact clothes washers, and 0.8 years for front-loading compact clothes washers. A significant fraction of consumers, however, experience an LCC net cost for all product classes except for front-loading compact: 8 percent for top-loading standard clothes washers, 45 percent for front-loading standard clothes washers, and 13 percent for top-loading compact clothes washers. In addition, TSL 4 significantly raises the first cost of both top-loading and front-loading clothes washers, and DOE is concerned some low-income consumers may be compelled to delay or forgo new purchases.

At TSL 4, the projected change in INPV ranges from an increase of $205.0 million to a decrease of $1,256.4 million. At this TSL, manufacturers would be required to overhaul both front-loading and top-loading platforms by the 2015 compliance date to meet demand. DOE estimates that it would cost the industry approximately $692 million in product and capital conversion costs at TSL 4. These costs reflect substantial platform changes to both top-loading and front-loading clothes washers by 2015, represent a significant portion of the total value of the industry, and trigger capacity concerns in light of the magnitude and timing of the necessary changes. In addition, manufacturers could face a substantial impact on profitability at TSL 4. Because manufacturers earn a premium for ENERGY STAR products and additional profit for products that exceed the ENERGY STAR level, collapsing the market to a few commodity products without efficiency differentiators makes it unlikely that manufactures could maintain their base-case profitability on these products after standards. Because of the effect, DOE expects that TSL 4 would yield impacts closer to the high end of the range of INPV impacts. If the high end of the range of impacts is reached, as DOE expects, TSL 4 could result in a net loss of 48.6 percent in INPV to clothes washer manufacturers.

The Secretary concludes that at TSL 4 for residential clothes washers, the benefits of energy savings, water savings, positive NPV of consumer benefits, generating capacity reductions, emission reductions, and the estimated monetary value of the CO_2 emissions reductions would be outweighed by the economic burden on a significant fraction of consumers due to the large increase in product cost and the impacts on manufacturers, including the conversion costs and profit margin impacts that could result in a very large reduction in INPV for manufacturers and the risk of manufacturer capacity constraints resulting from the necessary changes by 2015. Consequently, the Secretary has concluded that TSL 4 is not economically justified.

DOE then considered TSL 3. TSL 3 would save 2.04 quads of energy and 3.03 trillion gallons of water, amounts DOE considers significant. Under TSL 3, the NPV of consumer benefit would be $13.01 billion, using a discount rate of 7 percent, and $31.29 billion, using a discount rate of 3 percent.

The cumulative emissions reductions at TSL 3 are 113 Mt of CO_2, 94.2 thousand tons of NO_X, and 0.269 ton of Hg. The estimated monetary value of the CO_2 emissions reductions at TSL 3 ranges from $530 million to $8,457 million. Total generating capacity in 2045 is estimated to decrease by 1.30 GW under TSL 3.

At TSL 3, the average LCC impact is a savings of $268 in 2015 and $366 in 2018 for top-loading standard clothes washers, a savings of $37 for front-loading standard clothes washers, a savings of $159 in 2015 and $312 in 2018 for top-loading compact clothes washers, and a savings of $54 for front-loading compact clothes washers. The median payback period is 0.4 years in 2015 and 0.9 years in 2018 for top-loading standard clothes washers, 1.3 years for front-loading standard clothes washers, 0.5 years in 2015 and 2.1 years in 2018 for top-loading compact clothes washers, and 0.8 years for front-loading compact clothes washers. The fraction of consumers experiencing an LCC cost is small—less than 1 percent in 2015 and 3 percent in 2018 for top-loading standard clothes washers, 1.5 percent for front-loading standard clothes washers, and 1.5 percent in 2015 and 13 percent in 2018 for top-loading compact clothes washers. No consumers experience an LCC cost for front-loading compact clothes washers. The much lower first cost of washers meeting TSL 3, combined with the fact that the vast majority of consumers experience either net LCC benefits or no impacts at TSL 3, mitigates DOE's concern that some low-income consumers would be compelled to delay or forgo new purchases.

At TSL 3, the projected change in INPV ranges from an increase of $96.4 million to a decrease of $858.8 million. For most manufacturers, the efficiency levels for top-loading clothes washers at TSL 3 correspond to incremental product conversion by 2015 and a platform redesign by 2018. These compliance dates mitigate capacity risk to manufacturers and their supply chains and afford manufacturers the flexibility to spread capital requirements, engineering resources, and other conversion activities over a longer period of time depending on the individual needs of each manufacturer. These factors at TSL 3 mitigate DOE's concerns about manufacturers' ability to match production capacity to market demand. At TSL 3, DOE recognizes the risk of negative impacts if manufacturers' expectations concerning reduced profit margins are realized. However, the additional flexibility of the compliance dates and range of efficiency levels above TSL 3 afford manufacturers room to maintain higher value products. Therefore, DOE expects impacts to be closer to the low end of the range of impacts.

The Secretary concludes that at TSL 3 for residential clothes washers, the benefits of energy savings, water savings, positive NPV of consumer benefits, generating capacity reductions, emission reductions, the estimated monetary value of the CO_2 emissions reductions, and favorable consumer LCC savings and payback period for more than 97 percent of consumers outweigh the LCC costs for less than 3 percent of consumers and the conversion costs and profit margin impacts that could result in a reduction in INPV for manufacturers.

In addition, the efficiency levels in TSL 3 correspond to the recommended levels in the Joint Petition, which DOE believes sets forth a statement by interested persons that are fairly representative of relevant points of view (including representatives of manufacturers of covered products, States, and efficiency advocates) and contains recommendations with respect to an energy conservation standard that are in accordance with 42 U.S.C. 6295(o). Moreover, DOE has encouraged the submission of consensus agreements as a way for diverse interested parties to develop an independent and probative analysis useful in DOE standard setting and to expedite the rulemaking process. DOE also believes that the standard levels recommended in the consensus agreement may increase the likelihood for regulatory compliance, while decreasing the risk of litigation.

After considering the analysis, comments on the framework document, and the benefits and burdens of TSL 3, the Secretary concludes that this TSL will offer the maximum improvement in efficiency that is technologically feasible and economically justified, and will result in the significant conservation of energy. Therefore, DOE proposes to adopt TSL 3 for residential clothes washers. The proposed amended energy conservation standards for residential clothes washers, which are a minimum allowable integrated modified energy factor (IMEF) and maximum allowable integrated water factor (IWF), are shown in Table II.3.

TABLE II.3—PROPOSED AMENDED ENERGY CONSERVATION STANDARDS FOR CLOTHES WASHERS

Product class	Effective March 7, 2015		Effective January 1, 2018	
	Minimum IMEF *	Maximum IWF †	Minimum IMEF *	Maximum IWF †
1. Top-loading, Compact (less than 1.6 ft^3 capacity)	0.86	14.4	1.15	12.0
2. Top-loading, Standard	1.29	8.4	1.57	6.5
3. Front-loading, Compact (less than 1.6 ft^3 capacity)	1.13	8.3	N/A	
4. Front-loading, Standard	1.84	4.7	N/A	

* IMEF (integrated modified energy factor) is calculated as the clothes container capacity in cubic feet divided by the sum, expressed in kilowatt-hours (kWh), of: (1) the total weighted per-cycle hot water energy consumption; (2) the total weighted per-cycle machine electrical energy consumption; (3) the per-cycle energy consumption for removing moisture from a test load; and (4) the per-cycle standby and off mode energy consumption.

† IWF (integrated water consumption factor is calculated as the sum, expressed in gallons per cycle, of the total weighted per-cycle water consumption for all wash cycles divided by the clothes container capacity in cubic feet.

B. Summary of Benefits and Costs (Annualized) of the Standards

The benefits and costs of today's standards can also be expressed in terms of annualized values. The annualized monetary values are the sum of (1) the annualized national economic value, expressed in 2010$, of the benefits from operating products that meet the proposed standards (consisting primarily of operating cost savings from using less energy and water, minus increases in product purchase costs, which is another way of representing consumer NPV), and (2) the monetary value of the benefits of emission reductions, including CO_2 emission reductions.[4] The value of the CO_2 reductions, otherwise known as the Social Cost of Carbon (SCC), is calculated using a range of values per metric ton of CO_2 developed by a recent interagency process.

Although combining the values of operating savings and CO_2 reductions provides a useful perspective, two issues should be considered. First, the national operating savings are domestic U.S. consumer monetary savings that occur as a result of market transactions while the value of CO_2 reductions is based on a global value. Second, the assessments of operating cost savings and SCC are performed with different methods that use quite different time frames for analysis. The national operating cost savings is measured for the lifetime of products shipped in 2015–2044. The SCC values, on the other hand, reflect the present value of all future climate-related impacts resulting from the emission of one ton of carbon dioxide in each year. These impacts continue well beyond 2100.

Table II.4 shows the annualized values for clothes washers. Using a 7-percent discount rate for benefits and costs other than CO_2 reductions, for which DOE used a 3-percent discount rate along with the SCC series corresponding to a value of $22.3/ton in 2010, the cost of the standards for clothes washers in today's rule is $185 million per year in increased equipment costs, while the annualized benefits are $1,234 million per year in reduced equipment operating costs, $141.7 million in CO_2 reductions, and $5.4 million in reduced NO_X emissions. In this case, the net benefit amounts to $1.20 billion per year. Using a 3-percent discount rate and for all benefits and

[4] DOE used a two-step calculation process to convert the time-series of costs and benefits into annualized values. First, DOE calculated a present value in 2011, the year used for discounting the NPV of total consumer costs and savings, for the time-series of costs and benefits using discount rates of 3 and 7 percent for all costs and benefits except for the value of CO_2 reductions. For the latter, DOE used a range of discount rates, as shown in Table II.4. From the present value, DOE then calculated the fixed annual payment over a 30-year period that yields the same present value. The fixed annual payment is the annualized value. Although DOE calculated annualized values, this does not imply that the time-series of cost and benefits from which the annualized values were determined would be a steady stream of payments.

costs and the SCC series corresponding to a value of $22.3/ton in 2010, the cost of the standards for clothes washers in today's rule is $212 million per year in increased equipment costs, while the benefits are $1,808 million per year in reduced operating costs, $141.7 million in CO_2 reductions, and $8.0 million in reduced NO_X emissions. In this case, the net benefit amounts to $1.75 billion per year.

TABLE II.4—ANNUALIZED BENEFITS AND COSTS OF PROPOSED AMENDED STANDARDS (TSL 3) FOR RESIDENTIAL CLOTHES WASHERS

	Discount rate	Monetized (million 2010$/year)		
		Primary estimate*	Low net benefits estimate*	High net benefits estimate*
Benefits				
Operating Cost Savings	7%	1234	1101	1379.
	3%	1808	1587	2042.
CO_2 Reduction at $4.9/t**	5%	34.5	31.7	37.4.
CO_2 Reduction at $22.3/t**	3%	142	130	154.
CO_2 Reduction at $36.5/t**	2.5%	226	207	246.
CO_2 Reduction at $67.6/t**	3%	431	396	469.
NO_X Reduction at $2,537/t**	7%	5.40	5.03	5.82.
	3%	8.01	7.39	8.68.
Total†	7% plus CO_2 range	1274 to 1671	1137 to 1502	1423 to 1854.
	7%	1381	1236	1539.
	3% plus CO_2 range	1851 to 2248	1626 to 1991	2089 to 2520.
	3%	1958	1725	2205.
Costs				
Incremental Product Costs	7%	185	258	200.
	3%	212	309	230.
Total Net Benefits				
Total†	7% plus CO_2 range	1088 to 1485	880 to 1244	1223 to 1654.
	7%	1196	978	1339.
	3% plus CO_2 range	1639 to 2036	1317 to 1682	1859 to 2291.
	3%	1746	1416	1976.

* The Primary, Low Benefit, and High Benefit Estimates utilize forecasts of energy prices and housing starts (which affect product shipments) from the *AEO2010* Reference case, Low Economic Growth case, and High Economic Growth case, respectively. In addition, incremental product costs reflect a declining trend using the default product price trend in the Primary Estimate and High Benefits Estimate, and constant product prices in the Low Benefits Estimate. Because product prices are constant in the Low Benefits Estimate, the incremental product costs are higher than in the other two estimates. Although the price trends in the Primary Estimate and the High Benefits Estimate are the same, the incremental product costs are higher in the High Benefits Estimate because this case assumes High Economic Growth and thus has more product shipments. The approach used for forecasting product prices is explained in section IV.F.1.

** The CO_2 values represent global values (in 2010$) of the social cost of CO_2 emissions in 2010 under several scenarios. The values of $4.9, $22.3, and $36.5 per ton are the averages of SCC distributions calculated using 5%, 3%, and 2.5% discount rates, respectively. The value of $67.6 per ton represents the 95th percentile of the SCC distribution calculated using a 3% discount rate. The value for NO_X (in 2010$) is the average of the low and high values used in DOE's analysis.

† Total Benefits for both the 3% and 7% cases are derived using the SCC value calculated at a 3% discount rate, which is $22.3/ton in 2010 (in 2010$). In the rows labeled as "7% plus CO_2 range" and "3% plus CO_2 range," the operating cost and NO_X benefits are calculated using the labeled discount rate, and those values are added to the full range of CO_2 values.

III. Public Participation

A. Submission of Comments

DOE will accept comments, data, and information regarding this proposed rule until the date provided in the **DATES** section at the beginning of this proposed rule. Interested parties may submit comments, data, and other information using any of the methods described in the **ADDRESSES** section at the beginning of this proposed rule.

Submitting comments via regulations.gov. The *regulations.gov* Web page will require you to provide your name and contact information. Your contact information will be viewable to DOE Building Technologies staff only. Your contact information will not be publicly viewable except for your first and last names, organization name (if any), and submitter representative name (if any). If your comment is not processed properly because of technical difficulties, DOE will use this information to contact you. If DOE cannot read your comment due to technical difficulties and cannot contact you for clarification, DOE may not be able to consider your comment.

However, your contact information will be publicly viewable if you include it in the comment itself or in any documents attached to your comment. Any information that you do not want to be publicly viewable should not be included in your comment, nor in any document attached to your comment. Otherwise, persons viewing comments will see only first and last names, organization names, correspondence containing comments, and any documents submitted with the comments.

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Include contact information each time you submit comments, data, documents, and other information to DOE. Email submissions are preferred. If you submit via mail or hand delivery/courier, please provide all items on a CD, if feasible. It is not necessary to submit printed copies. No facsimiles (faxes) will be accepted.

Comments, data, and other information submitted to DOE electronically should be provided in PDF (preferred), Microsoft Word or Excel, WordPerfect, or text (ASCII) file format. Provide documents that are not secured, that are written in English, and that are free of any defects or viruses. Documents should not contain special characters or any form of encryption and, if possible, they should carry the electronic signature of the author.

Campaign form letters. Please submit campaign form letters by the originating organization in batches of between 50 to 500 form letters per PDF or as one form letter with a list of supporters' names compiled into one or more PDFs. This reduces comment processing and posting time.

Confidential business information. According to 10 CFR 1004.11, any person submitting information that he or she believes to be confidential and exempt by law from public disclosure should submit via email, postal mail, or hand delivery/courier two well-marked copies: One copy of the document marked confidential including all the information believed to be confidential, and one copy of the document marked non-confidential with the information believed to be confidential deleted. Submit these documents via email or on a CD, if feasible. DOE will make its own determination about the confidential status of the information and treat it according to its determination.

Factors of interest to DOE when evaluating requests to treat submitted information as confidential include: (1) A description of the items; (2) whether and why such items are customarily treated as confidential within the industry; (3) whether the information is generally known by or available from other sources; (4) whether the information has previously been made available to others without obligation concerning its confidentiality; (5) an explanation of the competitive injury to the submitting person which would result from public disclosure; (6) when such information might lose its confidential character due to the passage of time; and (7) why disclosure of the information would be contrary to the public interest.

It is DOE's policy that all comments may be included in the public docket, without change and as received, including any personal information provided in the comments (except information deemed to be exempt from public disclosure).

B. Public Meeting

If DOE withdraws the direct final rule published elsewhere in today's **Federal Register** pursuant to 42 U.S.C. 6295(p)(4)(C), DOE will hold a public meeting to allow for additional comment on this proposed rule. DOE will publish notice of any meeting in the **Federal Register**.

C. Issues on which DOE seeks Comment

As stated previously, pursuant to 42 U.S.C. 6295(p)(4), DOE promulgated a direct final rule establishing standards for residential clothes washers elsewhere in today's **Federal Register**. The standards established in the direct final rule are the same standards proposed in today's NOPR. In promulgating the direct final rule, DOE carefully considered the Joint Petition submitted to DOE, which contained a consensus recommendation for amended energy conservation standards for residential clothes washers. For the reasons stated in the direct final rule, the Secretary determined that the ''Consensus Agreement'' was submitted by interested persons who are fairly representative of relevant points of view on this matter. The Secretary also determined, for the reasons set forth in the direct final rule, that the standards contained in the Consensus Agreement comport with the standard-setting criteria set forth under 42 U.S.C. 6295(o). Therefore, the Secretary promulgated the direct final rule establishing the amended energy conservation standards for residential clothes washers.

(1) As required by the same statutory provision, DOE is also simultaneously publishing this NOPR and providing for a 110-day public comment period. Should DOE determine to proceed with this NOPR, or to gather additional data for future energy conservation standards activities for residential clothes washers, DOE will consider any comments and data received on these proposed standards. Although comments are welcome on all aspects of this rulemaking, DOE is particularly interested in comments on the following:

(1) Impacts of the standards that may lessen or improve the utility or performance of the covered products. These impacts may include increased cycle times to wash clothes, ability to achieve good wash performance (*e.g.,* cleaning and rinsing), increased longevity of clothing, improved ergonomics of washer use, increase in noise, and other potential impacts.

(2) The 2015 and 2018 compliance dates for the proposed standards and whether these compliance dates adequately consider the typical clothes washer model design cycle for manufacturers.

(3) Whether repair costs for residential clothes washers would increase at the efficiency levels indicated in today's rule due to any changes in the design and materials and components used in order to comply with the new efficiency standards.

(4) Where there would be any anticipated changes in the consumption of complementary goods (*e.g.,* laundry detergent, stain removers, fabric softeners) that may result from the proposed standards.

(5) Whether DOE should incorporate the cost of risers or storage drawers (also referred to as pedestals) into the baseline installation costs for front-loading machines.

Changes in the Utility of the Products

DOE has prepared a technical support document (TSD) that analyzed the effect of this rule on, among other things, life cycle costs, payback periods and other consumer-related impacts. However, there are other facets of consumer welfare that are not explicitly captured in this analysis, including washing performance, increased longevity of clothing, and noise. While information gathered in the course of this rulemaking did not demonstrate a linkage between these topics and efficiency standards, DOE is seeking comment and information on how consumers value changes in these attributes and if those values should be incorporated into DOE analysis.

Also, although it is outside the scope of this rule, DOE may consider seeking information on whether to account for wash performance and fabric care in test procedures for clothes washers.

2015 and 2018 Compliance Dates

DOE is seeking comment on redesign timelines anticipated by the manufacturers and how the 2015 and 2018 compliance dates may affect those timelines. DOE's manufacturer impact analysis is based on information provided by the manufacturer and supports the positions that manufacturers will need to make only minor redesign to comply with the 2015 standards, though the 2018 standards could require more substantial redesigns. Accepting that manufacturers fully considered their cost implications prior to entering voluntarily the consensus agreement, DOE assumes that manufacturers would not have agreed to compliance dates they could not meet or that imposed prohibitive costs. However, depending on how the redesign timeline and the compliance dates coincide, the cost estimates may be affected, for example, due to sunk cost, as well as the anticipated market shares of front-loading versus top-loading clothes washers.

IV. Procedural Issues and Regulatory Review

The regulatory reviews conducted for this proposed rule are identical to those conducted for the direct final rule published elsewhere in today's **Federal Register**. Please see the direct final rule for further details.

V. Approval of the Office of the Secretary

The Secretary of Energy has approved publication of today's proposed rule.

List of Subjects

10 CFR Part 429

Administrative practice and procedure, Confidential business information, Energy conservation, Household appliances, and Reporting and recordkeeping requirements.

10 CFR Part 430

Administrative practice and procedure, Confidential business information, Energy conservation, Household appliances, Imports, Intergovernmental relations, and Small businesses.

Issued in Washington, DC, on May 11, 2012.

David Danielson,

Assistant Secretary, Energy Efficiency and Renewable Energy.

For the reasons set forth in the preamble, DOE proposes to amend parts 429 and 430 of title 10 of the Code of Federal Regulations, as set forth below:

PART 429—CERTIFICATION, COMPLIANCE, AND ENFORCEMENT FOR CONSUMER PRODUCTS AND COMMERCIAL AND INDUSTRIAL EQUIPMENT

1. The authority citation for part 429 continues to read as follows:

Authority: 42 U.S.C. 6291–6317.

2. In § 429.20 revise paragraph (b)(2) to read as follows:

§ 429.20 Residential clothes washers.

* * * * *

(b) * * *

(2) Pursuant to § 429.12(b)(13), a certification report shall include the following public product-specific information:

(i) For residential clothes washers manufactured before March 7, 2015: The modified energy factor (MEF) in cubic feet per kilowatt hour per cycle (cu ft/kWh/cycle) and the capacity in cubic feet (cu ft). For standard-size residential clothes washers, a water factor (WF) in gallons per cycle per cubic feet (gal/cycle/cu ft).

(ii) For residential clothes washers manufactured on or after March 7, 2015: The integrated modified energy factor (IMEF) in cu ft/kWh/cycle, the integrated water factor (IWF) in gal/cycle/cu ft, the capacity in cu ft and the type of loading (top-loading or front-loading).

* * * * *

PART 430—ENERGY CONSERVATION PROGRAM FOR CONSUMER PRODUCTS

3. The authority citation for part 430 continues to read as follows:

Authority: 42 U.S.C. 6291–6309; 28 U.S.C. 2461 note.

4. In § 430.32 revise paragraph (g) to read as follows:

§ 430.32 Energy and water conservation standards and their effective dates.

* * * * *

(g) *Clothes washers.* (1) Clothes washers manufactured on or after January 1, 2007 shall have a Modified Energy Factor no less than:

Product class	Modified energy factor (cu.ft./kWh/cycle)
i. Top-loading, Compact (less than 1.6 ft^3 capacity)	0.65.
ii. Top-loading, Standard (1.6 ft^3 or greater capacity)	1.26.
iii. Top-Loading, Semi-Automatic	[1] Not Applicable.
iv. Front-loading	1.26.
v. Suds-saving	[1] Not Applicable.

[1] Must have an unheated rinse water option.

(2) All top-loading or front-loading standard-size residential clothes washers manufactured on or after January 1, 2011, and before March 7, 2015, shall meet the following standard—

(i) A Modified Energy Factor of at least 1.26; and

(ii) A Water Factor of not more than 9.5.

(3) Clothes washers manufactured on or after March 7, 2015, and before January 1, 2018, shall have an Integrated Modified Energy Factor no less than, and an Integrated Water Factor no greater than:

Product class	Integrated modified energy factor (cu.ft./kWh/cycle)	Integrated water factor (gal/cycle/cu.ft.)
i. Top-loading, Compact (less than 1.6 ft^3 capacity)	0.86	14.4
ii. Top-loading, Standard (1.6 ft^3 or greater capacity)	1.29	8.4
iii. Front-loading, Compact (less than 1.6 ft^3 capacity)	1.13	8.3
iv. Front-loading, Standard (1.6 ft^3 or greater capacity)	1.84	4.7

(4) Clothes washers manufactured on or after January 1, 2018 shall have an Integrated Modified Energy Factor no less than, and an Integrated Water Factor no greater than:

Product class	Integrated modified energy factor (cu.ft./kWh/cycle)	Integrated water factor (gal/cycle/cu.ft.)
i. Top-loading, Compact (less than 1.6 ft^3 capacity)	1.15	12.0
ii. Top-loading, Standard (1.6 ft^3 or greater capacity)	1.57	6.5
iii. Front-loading, Compact (less than 1.6 ft^3 capacity)	1.13	8.3
iv. Front-loading, Standard (1.6 ft^3 or greater capacity)	1.84	4.7

* * * * *

[FR Doc. 2012–12319 Filed 5–30–12; 8:45 am]

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H.R. 4045/P.L. 112–120
To modify the Department of Defense Program Guidance relating to the award of Post-Deployment/Mobilization Respite Absence administrative absence days to members of the reserve components to exempt any member whose qualified mobilization commenced before October 1, 2011, and continued on or after that date, from the changes to the program guidance that took effect on that date. (May 25, 2012; 126 Stat. 343)

H.R. 4967/P.L. 112–121

Temporary Bankruptcy Judgeships Extension Act of 2012 (May 25, 2012; 126 Stat. 346)

Last List May 18, 2012

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