Federal Register

7–20–07

Vol. 72 No. 139

Friday

July 20, 2007

Pages 39727–40060

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

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

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

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

The **Federal Register** is published in paper and on 24x microfiche. It is also available online at no charge as one of the databases on GPO Access, a service of the U.S. Government Printing Office.

The online edition of the **Federal Register** *www.gpoaccess.gov/nara,* available through GPO Access, is issued under the authority of the Administrative Committee of the Federal Register as the official legal equivalent of the paper and microfiche editions (44 U.S.C. 4101 and 1 CFR 5.10). It is updated by 6 a.m. each day the **Federal Register** is published and includes both text and graphics from Volume 59, Number 1 (January 2, 1994) forward.

For more information about GPO Access, contact the GPO Access User Support Team, call toll free 1-888-293-6498; DC area 202-512-1530; fax at 202-512-1262; or via e-mail at *gpoaccess@gpo.gov.* The Support Team is available between 7:00 a.m. and 9:00 p.m. Eastern Time, Monday–Friday, except official holidays.

The annual subscription price for the **Federal Register** paper edition is $749 plus postage, or $808, plus postage, for a combined **Federal Register, Federal Register** Index and List of CFR Sections Affected (LSA) subscription; the microfiche edition of the **Federal Register** including the **Federal Register** Index and LSA is $165, plus postage. Six month subscriptions are available for one-half the annual rate. The prevailing postal rates will be applied to orders according to the delivery method requested. The price of a single copy of the daily **Federal Register,** including postage, is based on the number of pages: $11 for an issue containing less than 200 pages; $22 for an issue containing 200 to 400 pages; and $33 for an issue containing more than 400 pages. Single issues of the microfiche edition may be purchased for $3 per copy, including postage. Remit check or money order, made payable to the Superintendent of Documents, or charge to your GPO Deposit Account, VISA, MasterCard, American Express, or Discover. Mail to: New Orders, Superintendent of Documents, P.O. Box 371954, Pittsburgh, PA 15250-7954; or call toll free 1-866-512-1800, DC area 202-512-1800; or go to the U.S. Government Online Bookstore site, see *bookstore.gpo.gov.*



**How To Cite This Publication:** Use the volume number and the page number. Example: 72 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.

## SUBSCRIPTIONS AND COPIES

| | |
|---|---|
| **PUBLIC** | |
| **Subscriptions:** | |
| Paper or fiche | **202–512–1800** |
| Assistance with public subscriptions | **202–512–1806** |
| **General online information** | **202–512–1530; 1–888–293–6498** |
| **Single copies/back copies:** | |
| Paper or fiche | **202–512–1800** |
| Assistance with public single copies | **1–866–512–1800 (Toll-Free)** |
| **FEDERAL AGENCIES** | |
| **Subscriptions:** | |
| Paper or fiche | **202–741–6005** |
| Assistance with Federal agency subscriptions | **202–741–6005** |

# Contents

**Federal Register**

Vol. 72, No. 139

Friday, July 20, 2007

---

**Separate Parts In This Issue**



---

**Reader Aids**

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

To subscribe to the Federal Register Table of Contents LISTSERV electronic mailing list, go to http://listserv.access.gpo.gov and select Online mailing list archives, FEDREGTOC-L, Join or leave the list (or change settings); then follow the instructions.

## CFR PARTS AFFECTED IN THIS ISSUE

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

# Rules and Regulations

Federal Register

Vol. 72, No. 139

Friday, July 20, 2007



## SMALL BUSINESS ADMINISTRATION

## 2 CFR Part 2700

## 13 CFR Parts 134 and 145

**RIN 3245–AF63**

## Small Business Administration Implementation of OMB Guidance on Nonprocurement Debarment and Suspension

**AGENCY:** U.S. Small Business Administration.

**ACTION:** Direct final rule.

**SUMMARY:** The U.S. Small Business Administration (SBA) is moving its regulations on nonprocurement debarment and suspension from their current location in title 13 of the Code of Federal Regulations (CFR) to title 2 of the CFR, and is adopting the format established by the Office of Management and Budget (OMB). This rule establishes a new 2 CFR part 2700 that adopts OMB's final government-wide guidance on nonprocurement debarment and suspension and contains supplemental SBA nonprocurement debarment and suspension provisions. In addition, this rule removes the existing SBA nonprocurement debarment and suspension regulations and makes a conforming change and minor procedural clarifications. These changes constitute an administrative simplification that makes no substantive change in SBA policy or procedures for nonprocurement debarment and suspension. SBA is also amending a provision in its Rules of Procedure Governing Cases Before the Office of Hearings and Appeals (13 CFR 134.102(p)) to update the reference to SBA's nonprocurement debarment and suspension regulations.

**DATES:** *Effective Date*: This rule is effective September 18, 2007 without further action.

**FOR FURTHER INFORMATION CONTACT:** Kevin Harber, Office of General Counsel, U.S. Small Business Administration, 409 Third St., SW., Ste. 5700, Washington, DC 20416, telephone 202–619–1602 and e-mail: *Kevin.Harber@sba.gov*.

**SUPPLEMENTARY INFORMATION:**

### I. Introduction

On May 11, 2004, OMB established title 2 of the CFR with two subtitles (69 FR 2627). Subtitle A, ''Government-wide Grants and Agreements,'' contains OMB policy guidance to Federal agencies on grants and agreements. Subtitle B, ''Federal Agency Regulations for Grants and Agreements,'' contains Federal agencies' regulations implementing the OMB guidance, as it applies to grants and other financial assistance agreements and nonprocurement transactions.

On August 31, 2005, OMB published interim final guidance for government-wide nonprocurement debarment and suspension in the **Federal Register** (70 FR 51863). The guidance was located in title 2 of the CFR as new subtitle A, chapter 1, part 180. The interim final guidance updated previous OMB guidance that was issued pursuant to Executive Order 12549, ''Debarment and Suspension'' (February 18, 1986), which gave government-wide effect to each agency's nonprocurement debarment and suspension actions. Section 6 of the Executive Order authorized OMB to issue guidance to Executive agencies on nonprocurement debarment and suspension, including provisions prescribing government-wide criteria and minimum due process procedures. Section 3 directed Executive agencies to issue regulations implementing the Executive Order that are consistent with the OMB guidelines. The interim final guidance at 2 CFR part 180 conforms the OMB guidance with the Federal agencies' November 26, 2003, update to the common rule on nonprocurement debarment and suspension (*see* 70 FR 51864). Although substantively the same as the common rule, OMB's interim final guidance was published in a form suitable for agency adoption, thus eliminating the need for each agency to repeat the full text of the OMB government-wide guidance in its implementing regulations. This new approach is intended to make it easier for recipients of covered transactions or respondents in suspension or debarment actions to discern agency-to-agency variations from the common rule language; reduce the volume of Federal regulations in the CFR; and streamline the process for updating the government-wide requirements on nonprocurement debarment and suspension (70 FR 51864). On November 15, 2006, OMB published a final rule adopting the interim final guidance with changes (71 FR 66431).

This direct final rule places SBA's nonprocurement debarment and suspension regulations in subtitle B of title 2 of the CFR, along with other agencies' nonprocurement debarment and suspension rules. This action was required by the OMB interim final guidance, which was made final on November 15, 2006 (*see* 2 CFR 180.20, 180.25, 180.30 and 180.35). The new CFR part 2700 adopts the OMB guidelines with additions and clarifications that SBA made to the common rule on nonprocurement debarment and suspension in the SBA rule published on November 26, 2003 (68 FR 66544–70). The substance of SBA's nonprocurement debarment and suspension is unchanged. SBA is removing 13 CFR part 145, which was last revised as part of the November 2003 common rule.

SBA is not soliciting public comment on this rule and is instead issuing this rule as a direct final rule. Under 5 U.S.C. 553(b)(3)(A) agencies are not required to undergo notice and comment procedure for ''interpretative rules, general statements of policy, or rules of agency organization, procedure, or practice.'' Because this rule adopts OMB's published guidelines, which followed notice and comment procedures, and collocates SBA's specific nonprocurement suspension and debarment rules to title 2 of the CFR, we believe that it falls under the exception cited above.

*Compliance With Executive Orders 13132, 12988 and 12866, the Regulatory Flexibility Act (5 U.S.C. 601–602), and the Paperwork Reduction Act (44 U.S.C. Ch. 35)*

This regulation 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. Therefore, for the purposes of Executive Order 13132, SBA determines that this rule has no federalism implications warranting preparation of a federalism assessment.

OMB has determined this rule is not a ''significant regulatory action'' under Executive Order 12866.

This action meets applicable standards set forth in sections 3(a) and 3(b)(2) of Executive Order 12988, Civil Justice Reform, to minimize litigation, eliminate ambiguity, and reduce burden. The action does not have retroactive or preemptive effect.

SBA has determined that this rule does not impose additional reporting or recordkeeping requirements under the Paperwork Reduction Act, 44 U.S.C. Chapter 35.

The Regulatory Flexibility Act (RFA), 5 U.S.C. 601, requires administrative agencies to consider the effect of their actions on small entities, small non-profit enterprises, and small local governments. Pursuant to the RFA, when an agency issues a rulemaking, the agency must prepare a regulatory flexibility analysis which describes the impact of the rule on small entities. However, section 605 of the RFA allows an agency to certify a rule, in lieu of preparing an analysis, if the rulemaking is not expected to have a significant economic impact on a substantial number of small entities. Within the meaning of the RFA, SBA certifies that this rule will not have a significant economic impact on a substantial number of small entities because the rule imposes no direct requirements on small entities.

**List of Subjects**

*2 CFR Part 2700*

Administrative practice and procedure, Debarment and suspension, Grant programs, Reporting and recordkeeping requirements.

*13 CFR Part 134*

Administrative practice and procedure, Claims, Equal access to justice, Lawyers, Organizations and functions (Government agencies).

*13 CFR Part 145*

Administrative practice and procedure, Government contracts, Grant programs, Loan programs, Reporting and recordkeeping requirements.

■ Accordingly, under the authority of 15 U.S.C. 634, SBA amends the Code of Federal Regulations, Title 2, Subtitle B, and Title 13, Chapter 1, as follows:

**Title 2—Grants and Agreements**

■ 1. Add Chapter XXVII, consisting of Part 2700 to Subtitle B to read as follows:

**Chapter XXVII—Small Business Administration**

## PART 2700—NONPROCUREMENT DEBARMENT AND SUSPENSION



**Authority:** Sec. 2455, Pub. L. 103–355, 108 Stat. 3327 (31 U.S.C. 6101 note); E.O. 12549 (3 CFR, 1986 Comp., p. 189); E.O. 12689 (3 CFR, 1989, 1986 Comp., p. 235); 15 U.S.C. 634(b)(6).

**§ 2700.10 What does this part do?**

This part adopts the Office of Management and Budget (OMB) guidance in subparts A through I of 2 CFR part 180, as supplemented by this part, as the SBA policies and procedures for nonprocurement debarment and suspension. It thereby gives regulatory effect for SBA to the OMB guidance as supplemented by this part. This part satisfies the requirements in section 3 of Executive Order 12549, ''Debarment and Suspension'' (3 CFR 1986 Comp., p. 189); Executive Order 12689, ''Debarment and Suspension'' (3 CFR 1989 Comp., p. 235); and section 2455 of the Federal Acquisition Streamlining Act of 1994, Pub. L. 103–355 (31 U.S.C. 6101 note).

**§ 2700.20 Does this part apply to me?**

This part and, through this part, pertinent portions of the OMB guidance in subparts A through I of 2 CFR part 180 (see table at 2 CFR 180.100(b)) apply to you if you are a—

(a) Participant or principal in a ''covered transaction'' (see subpart B of 2 CFR part 180 and the definition of ''nonprocurement transaction'' at 2 CFR 180.970);

(b) Respondent in an SBA suspension or debarment action;

(c) SBA debarment or suspension official; or

(d) SBA grants officer, agreements officer, or other official authorized to enter into any type of nonprocurement transaction that is a covered transaction.

**§ 2700.30 What policies and procedures must I follow?**

The SBA policies and procedures you must follow are the policies and procedures specified in each applicable section of the OMB guidance in subparts A through I of 2 CFR part 180, as that section is supplemented by the section in this part with the same section number. The contracts that are covered transactions, for example, are specified by section 220 of the OMB guidance (i.e., 2 CFR 180.220) as supplemented by section 220 of this part (i.e., § 2700.220). For any section of OMB guidance in Subparts A through I of 2 CFR 180 that has no corresponding section in this part, SBA policies and procedures are those in the OMB guidance.

### Subpart A—General

**§ 2700.137 Who in the Small Business Administration may grant an exception to let an excluded person participate in a covered transaction?**

The Director of the Office of Lender Oversight may grant an exception permitting an excluded person to participate in a particular covered transaction under SBA's financial assistance programs. For all other Agency programs, the Director of the Office of Business Operations may grant such an exception.

### Subpart B—Covered Transactions

**§ 2700.220 What contracts and subcontracts, in addition to those listed in 2 CFR 180.220, are covered transactions?**

In addition to the contracts covered under 2 CFR 180.22(b) of the OMB guidance, this part applies to any contract, regardless of tier, that is awarded by a contractor, subcontractor, supplier, consultant, or its agent or representative in any transaction, if the contract is to be funded or provided by the SBA under a covered nonprocurement transaction and the amount of the contract is expected to equal or exceed $25,000. This extends the coverage of the SBA nonprocurement suspension and debarment requirements to all lower tiers of subcontracts under covered nonprocurement transactions, as permitted under the OMB guidance at 2 CFR 180.200(c) (see optional lower tier coverage in the figure in the Appendix to 2 CFR part 180)

## Subpart C—Responsibilities of Participants Regarding Transactions

### § 2700.332 What methods must I use to pass requirements down to participants at lower tiers with whom I intend to do business?

You, as a participant, must include a term or condition in lower-tier transactions requiring lower-tier participants to comply with subpart C of the OMB guidance in 2 CFR part 180, as supplemented by this part.

## Subpart D—Responsibilities of Federal Agency Officials Regarding Transactions

### § 2700.437 What method do I use to communicate to a participant the requirements described in the OMB guidance at 2 CFR 180.435?

To communicate to a participant the requirements described in 2 CFR 180.435 of the OMB guidance, you must include a term or condition in the transaction that requires the participant's compliance with subpart C of 2 CFR part 180, as supplemented by subpart C of this part, and requires the participant to include a similar term or condition in lower-tier covered transactions.

## Subpart E–F—[Reserved]

## Subpart G—Suspension

### § 2700.765 How may I appeal my suspension?

(a) If the SBA suspending official issues a decision under § 180.755 to continue your suspension after you present information in opposition to that suspension under § 180.720, you may ask for review of the suspending official's decision in two ways:

(1) You may ask the suspending official to reconsider the decision for material errors of fact or law that you believe will change the outcome of the matter; or

(2) You may request that the SBA Office of Hearings and Appeals (OHA) review the suspending official's decision to continue your suspension within 30 days of your receipt of the suspending official's decision under § 180.755 or paragraph (a)(1) of this section. However, OHA may reverse the suspending official's decision only where OHA finds that the decision is based on a clear error of material fact or law, or where OHA finds that the suspending official's decision was arbitrary, capricious, or an abuse of discretion. You may appeal the suspending official's decision without requesting reconsideration, or you may appeal the decision of the suspending official on reconsideration. The procedures governing OHA appeals are set forth in 13 CFR part 134.

(b) A request for review under this section must be in writing; state the specific findings you believe to be in error; and include the reasons or legal bases for your position.

(c) OHA, in its discretion, may stay the suspension pending review of the suspending official's decision.

(d) The SBA suspending official and OHA must notify you of their decision under this section, in writing, using the notice procedures set forth at §§ 180.615 and 180.975.

## Subpart H—Debarment

### § 2700.890 How may I appeal my debarment?

(a) If the SBA debarring official issues a decision under § 180.870 to debar you after you present information in opposition to a proposed debarment under § 180.815, you may ask for review of the debarring official's decision in two ways:

(1) You may ask the debarring official to reconsider the decision for material errors of fact or law that you believe will change the outcome of the matter; or

(2) You may request that the SBA Office of Hearings and Appeals (OHA) review the debarring official's decision to debar you within 30 days of your receipt of the debarring official's decision under § 180.870 or paragraph (a)(1) of this section. However, OHA may reverse the debarring official's decision only where OHA finds that the decision is based on a clear error of material fact or law, or where OHA finds that the debarring official's decision was arbitrary, capricious, or an abuse of discretion. You may appeal the debarring official's decision without requesting reconsideration, or you may appeal the decision of the debarring official on reconsideration. The procedures governing OHA appeals are set forth in 13 CFR part 134.

(b) A request for review under this section must be in writing; state the specific findings you believe to be in error; and include the reasons or legal bases for your position.

(c) OHA, in its discretion, may stay the debarment pending review of the debarring official's decision.

(d) The SBA debarring official and OHA must notify you of their decision under this section, in writing, using the notice procedures set forth at §§ 180.615 and 180.975.

## Subpart I—Definitions

### § 2700.930 Debarring official (SBA supplement to government-wide definition at 2 CFR 180.930).

For SBA, the debarring official for financial assistance programs is the Director of the Office of Lender Oversight; for all other programs, the debarring official is the Director of the Office of Business Operations.

### § 2700.995 Principal (SBA supplement to government-wide definition at 2 CFR 180.995).

*Principal* means—

(a) Other examples of individuals who are principals in SBA covered transactions include:

(1) Principal investigators.

(2) Securities brokers and dealers under the section 7(a) Loan, Certified Development Company (CDC) and Small Business Investment Company (SBIC) programs.

(3) Applicant representatives under the section 7(a) Loan, CDC, SBIC, Small Business Development Center (SBDC), and section 7(j) programs.

(4) Providers of professional services under the section 7(a) Loan, CDC, SBIC, SBDC, and section 7(j) programs.

(5) Individuals that certify, authenticate or authorize billings.

(b) [Reserved]

### § 2700.1010 Suspending official (SBA supplement to government-wide definition at 2 CFR 180.1010).

For SBA, the suspending official for financial assistance programs is the Director of the Office of Lender Oversight; for all other programs, the suspending official is the Director of the Office of Business Operations.

## Subpart J—[Reserved]

**Title XIII—Business Credit and Assistance; Chapter I—Small Business Administration**

## PART 134—RULES OF PROCEDURE GOVERNING CASES BEFORE THE OFFICE OF HEARINGS AND APPEALS

■ 2. The authority citation for part 134 continues to read as follows:

**Authority:** 5 U.S.C. 504; 15 U.S.C. 632, 634(b)(6), 637(a), 648(l), 656(i), and 687(c); E.O. 12549, 51 FR 6370, 3 CFR, 1986 Comp., p. 189.

**§ 134.102 [Amended]**

■ 3. Section 134.102(p) of subpart B is amended by removing ''part 145 of this chapter'' and adding ''2 CFR parts 180 and 2700'' in its place.

## PART 145—[REMOVED]

■ 4. Under the authority of 15 U.S.C. 634, 13 CFR part 145 is removed.

Dated: July 12, 2007.

**Steven C. Preston,**

*Administrator.*

[FR Doc. E7–14035 Filed 7–19–07; 8:45 am]

**BILLING CODE 8025–01–P**

---

## DEPARTMENT OF AGRICULTURE

### Grain Inspection, Packers and Stockyards Administration

### 7 CFR Parts 800 and 810

**RIN 0580–AA91**

### United States Standards for Sorghum

**AGENCY:** Grain Inspection, Packers and Stockyards Administration, USDA.

**ACTION:** Final rule.

**SUMMARY:** We are revising the United States Standards for Sorghum to amend the definitions of the classes Sorghum, White sorghum, and Tannin sorghum, and to amend the definition of nongrain sorghum. We are amending the grade limits for broken kernels and foreign material (BNFM), and the subfactor foreign material (FM). Additionally, we are inserting a total count limit for other material into the standards and revising the method of certifying test weight (TW). Further, we are changing the inspection plan tolerances for BNFM and FM. These changes will help facilitate the marketing of sorghum.

**DATES:** *Effective Date:* June 1, 2008.

**FOR FURTHER INFORMATION CONTACT:** Patrick McCluskey at GIPSA, USDA, Suite 180 STOP 1404, 6501 Beacon Drive, Kansas City, MO, 64133; Telephone (816) 823–4639; fax (816) 823–4644.

**SUPPLEMENTARY INFORMATION:**

### Background

The United States Grain Standards Act (USGSA) authorizes the Secretary of Agriculture to establish official standards of kind and class, quality and condition for sorghum and other grains (7 U.S.C. 76). The United States Standards for Grain serve as the starting point to define grain quality in the marketplace. The United States Standards for Sorghum are in the regulations at 7 CFR 810.1401–810.1405.

On September 24, 2003, GIPSA was asked by the National Sorghum Producers (NSP, formerly National Grain Sorghum Producers) to initiate a review of the sorghum standards. Accordingly, in the December 17, 2003 **Federal Register** (68 FR 70201), through an Advance Notice of Proposed Rulemaking (ANPR) we requested views and comments on the sorghum standards. We received 35 comments to the ANPR. In the March 29, 2006 **Federal Register** (71 FR 15633–15639) we invited comments to our proposed rule identifying changes to the United States Standards for Sorghum to:

(1) Delete the reference to tannin content from definitions of Sorghum, Tannin sorghum and White sorghum, and define these classes based on the presence or absence of a pigmented testa (subcoat);

(2) Revise the definition of nongrain sorghum by deleting sorghum-sudangrass hybrids, sorgrass, and adding language referencing seeds of Sorghum bicolor (L.) Moench that appear atypical of grain sorghum;

(3) Reduce the grading limits for broken kernels and foreign material (BNFM) and the subfactor foreign material (FM);

(4) Insert a total count limit of 10 for other material used to determine sample grade factors;

(5) Report the certification of sorghum test weight in tenths of a pound per bushel; and

(6) Revise the sorghum breakpoints and associated grade limits for U.S. Nos. 1, 2, 3, and 4 BNFM and FM.

### Comment Review

We received 11 comments expressing a variety of views during the 60 day comment period for the proposed rule. We received comments from sorghum producers, producer and other industry organizations, grain handlers, and a sorghum researcher.

Overall, the comments supported all or a significant portion of the changes. A few commenters opposed specific portions of the changes. Some commenters requested additional changes beyond the scope of the proposed rule: Deleting the separate reference to FM but retaining the standard for total BNFM in the sorghum standard; deleting the reference to other grains from the definition of Damaged Kernels and Heat-damaged Kernels; and standardizing feed grain standards. We will consider these comments for future work on the standards.

### Sorghum Class Definitions

We proposed removing the reference to tannin content from definitions of Sorghum, Tannin sorghum and White sorghum, and define these classes based on the presence or absence of a pigmented testa (subcoat). We received nine comments on the proposal to remove the word tannin from the class definitions of Sorghum, Tannin sorghum, and White sorghum. Eight commenters directly supported the proposal as written and the other commenter did not oppose the proposal as written. No comments were received opposing the proposal. Of the supporting comments, most used identical language to state that defining sorghum based on the lack of a pigmented testa (subcoat) addressed the concerns of sorghum marketing organizations. Accordingly, we are amending the sorghum standards to remove the reference to tannin content from definitions of Sorghum, Tannin sorghum and White sorghum, and define these classes based on the presence or absence of a pigmented testa (subcoat), as set forth in the proposal.

### Nongrain Sorghum Definition

We proposed changing the definition of nongrain sorghum by (1) removing sorgrass and sorghum-sudangrass hybrids by (2) adding the words ''seeds of Sorghum bicolor (L.) Moench that appear atypical of grain sorghum.'' No commenters opposed or supported the proposal as written. Sorghum-sudangrass hybrids (botanically, Sorghum bicolor (L.) Moench), despite being grown as a forage crop, can either produce kernels which appear typical of grain sorghum or kernels that appear atypical of grain sorghum. We continue to believe that there is no reason to count kernels which appear typical of grain sorghum as nongrain sorghum, and this proposed change is made final herein.

Comments were received supporting the removal of sweet sorghum (sorgo) from the definition of nongrain sorghum because botanically, sweet sorghum is Sorghum bicolor (l.) Moench, as is grain sorghum and sorghum-sudangrass hybrid. We discussed removing sweet sorghum (sorgo) from the definition of nongrain sorghum in the proposed rule but did not propose it as a change to the standards, taking into account comments received as a result of the ANPR. Sweet sorghum plants can produce kernels that appear either typical or atypical of grain sorghum. Using the same rationale applied to sorghum-sudangrass hybrids, we believe there is no reason to count sweet sorghum kernels which appear typical of grain sorghum as nongrain sorghum. Further, the additional wording ''and seeds of Sorghum bicolor (L.) Moench that appear atypical of grain sorghum'' will allow sweet sorghum kernels which appear atypical of grain sorghum to be counted as nongrain sorghum. Therefore, based on the comments received, we will delete sweet sorghum (sorgo) from the definition of nongrain sorghum.

Finally, comments noted that producers appear to be restricted from receiving any program support from USDA because of the continuing classification of sweet sorghum as a nongrain. However, market conditions drive standards development and amendment, not eligibility for program support from USDA. Nonetheless, the definition of nongrain sorghum will be changed, but not because of this comment.

**BNFM and FM Grade Limits**

We proposed reducing the grade limits for BNFM and the subfactor FM. Comments noted that proposed revisions to the limits for BNFM and the subfactor FM would make it very difficult to achieve U.S. Number 1. We carefully considered the technical constraints and concerns raised as a result of this proposed change. Currently, U.S. Number 2 is the common trading standard and our analysis showed virtually no difference in the percentage of sorghum receiving the Number 2 grade (BNFM: 100.0 percent versus 99.8 percent; FM: 99.9 percent versus 95.8 percent) as a result of reducing the grade limits. We believe there will be no aggregate negative impact on the export sorghum market. Likewise, we believe changes to the sorghum standards must serve to improve market efficiency and encourage the production and delivery of high quality sorghum. Therefore, we are making no changes based on this comment.

**Total Other Material Count**

We proposed limiting the total number of pieces of other material upon which sample grade factor determinations are made. Eight comments were received supporting the proposal specifically or by inference. No comments were received opposing the proposal. Sorghum is used as a food grain in much of the world, thus the sample grade limit for sorghum should be consistent with the sample grade limits for other grains used as food. Accordingly, we are amending the sorghum standards to include a maximum count limit of 10 for the total of other material used to determine sample grade factors.

**Test Weight Certification**

We proposed revising the certification of sorghum test weight from TW from whole and half pounds, with a fraction of a half pound disregarded, to certification in tenths of a pound. One comment was received in support of the proposal, and no comments were received opposing the proposal as written. Accordingly, as set forth in the proposal, we are amending the grain standards to revise the certification of sorghum test weight.

**Inspection Plan Tolerances**

Shiplots, unit trains, and lash barge lots are inspected with a statistically based inspection plan. Inspection tolerances, commonly referred to as Breakpoints (BP), are used to determine acceptable quality. The revisions to the sorghum standards require revisions to some breakpoints. Accordingly, we are revising Table 15 of section 800.86(c)(2) to reflect the corresponding changes in the established inspection plan tolerances. The grade limits (GL) for sorghum are also revised in Table 15.

**Effective Date**

As specified in the USGSA (7 U.S.C. 76(b)), amendments to the standards cannot become effective less than one calendar year after public notification, unless in the judgment of the Secretary, the public health, interest, or safety require that they become effective sooner. In accordance with that section of the Act, it is determined that it is in the public interest to have this final rule effective on June 1, 2008, in order to coincide with the start of the 2008 sorghum harvest, and to facilitate domestic and export marketing of sorghum.

**Executive Order 12866 and Regulatory Flexibility Act**

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

The Regulatory Flexibility Act (RFA) (5 U.S.C. 601 *et seq.*) requires agencies to consider the economic impact of each rule on small entities and evaluate alternatives that would accomplish the objectives of the rule without unduly burdening small entities or erecting barriers that would restrict their ability to compete in the market.

We are amending the grain standards to change the definition of sorghum classes by deleting references to tannin and adding language referencing the presence or absence of a pigmented testa. We are amending the definition of nongrain sorghum by removing sorghum-sudangrass hybrids, sorgrass, and sweet sorghum (sorgo), and adding language referencing seeds of Sorghum bicolor (L.) Moench that appear atypical of grain sorghum. We are amending the grade and grade requirements for sorghum by reducing the grading limits for broken kernels and foreign material (BNFM) and the subfactor foreign material (FM), and inserting a total count limit of 10 for other material used to determine sample grade factors. We are amending the grain standards to report the certification of test weight in tenths of a pound. The changes made to the sorghum standards in this final rule are needed to ensure market-relevant standards and grades and facilitate the marketing of grain.

Under the provisions of the USGSA, grain exported from the United States must be officially inspected and weighed. The regulations and standards are applied equally to all entities.

We provide mandatory inspection and weighing services at 33 export elevators (including four floating elevators). All of these facilities are owned by multi-national corporations, large cooperatives, or public entities that do not meet the requirements for small entities established by the Small Business Administration.

The U.S. sorghum industry, including producers (approximately 40,000 (USDA–2002 Census of Agriculture)), handlers, processors, and merchandisers are the primary users of the U.S. Standards for Sorghum and utilize the official standards as a common trading language to market grain sorghum. We assume that some of the entities may be small.

In addition to GIPSA, there are 55 official agencies that perform official services under the USGSA. Most users of the official inspection and weighing services, and the entities that perform these services, do not meet the regulations for small entities.

The USGSA (7 U.S.C. 87f–1) requires the registration of all persons engaged in the business of buying, handling, weighing, or transporting grain for sale in foreign commerce. The USGSA regulations (7 CFR 800.30) define a foreign commerce grain business as persons who regularly engage in buying for sale, handling, weighing, or transporting grain totaling 15,000 metric tons or more during the preceding or current calendar year. At present, there are 92 registrants who account for practically 100 percent of U.S. sorghum exports, which for fiscal year (FY) 2005 totaled approximately 3,138,580 metric tons (MT). While most of the 89 registrants are large businesses, we assume some may be small.

GIPSA determined that this final rule will not have a significant economic impact on a substantial number of small entities, as defined in the Regulatory Flexibility Act.

**Paperwork Reduction Act**

Pursuant to the Paperwork Reduction Act of 1995, the existing information collection requirements are approved under OMB Number 0580–0013. No additional collection or recordkeeping requirements are imposed on the public by this final rule. Accordingly, OMB clearance is not required by section 350(h) of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.*, or OMB's implementing regulation at 5 CFR part 1320.

**E-Government Compliance**

We are committed to complying with the E-Government Act, to promote the use of the Internet and other information technologies to provide increased opportunities for citizen access to Government information and services, and for other purposes.

**Executive Order 12988**

Executive Order 12988, Civil Justice Reform, instructs each executive agency to adhere to certain requirements in the development of new and revised regulations in order to avoid unduly burdening the court system. The final rule was reviewed under this Executive Order and no additional related information has been obtained since then. This final rule is not intended to have a retroactive effect. The United States Grain Standards Act provides in Section 87g that no State or subdivision may require or impose any requirements or restrictions concerning the inspection, weighing, or description of grain under the USGSA. Otherwise, this final rule will not preempt any State or local laws, regulations, or policies, unless they present any irreconcilable conflict with this rule. There are no administrative procedures which must be exhausted prior to any judicial challenge to the provisions of this final rule.

**List of Subjects**

*7 CFR Part 800*

Administrative practice and procedure, Conflict of interests, Exports, Freedom of information, Grains, Intergovernmental relations, Penalties, Reporting and recordkeeping requirements.

*7 CFR Part 810*

Exports, Grains.

■ For reasons set out in the preamble, 7 CFR parts 800 and 810 are amended as follows:

## PART 800—GENERAL REGULATIONS

■ 1. Revise the authority citation for part 800 to read as follows:

**Authority:** 7 U.S.C. 71–87k.

■ 2. In § 800.86(c)(2), revise table 15 to read as follows:

### § 800.86 Inspection of shiplot, unit train and lash barge grain in single lots.

* * * * *

(c) * * *

(2) * * *

TABLE 15.—GRADE LIMITS (GL) AND BREAKPOINTS (BP) FOR SORGHUM

| Grade | Minimum test weight per bushel (pounds) | | Maximum limits of— | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | Damaged kernels | | | | Broken kernels and foreign material | | | |
| | | | Heat-damaged (percent) | | Total (percent) | | Total (percent) | | Foreign material (percent) | |
| | GL | BP | GL | BP | GL | BP | GL | BP | GL | BP |
| U.S. No. 1 | 57.0 | −0.4 | 0.2 | 0.1 | 2.0 | 1.1 | 3.0 | 0.5 | 1.0 | 0.4 |
| U.S. No. 2 | 55.0 | −0.4 | 0.5 | −0.4 | 5.0 | 1.8 | 6.0 | 0.6 | 2.0 | 0.5 |
| U.S. No. 3[1] | 53.0 | −0.4 | 1.0 | 0.5 | 10.0 | 2.3 | 8.0 | 0.7 | 3.0 | 0.6 |
| U.S. No. 4 | 51.0 | −0.4 | 3.0 | 0.8 | 15.0 | 2.8 | 10.0 | 0.8 | 4.0 | 0.7 |

[1] Sorghum that is distinctly discolored shall be graded not higher than U.S. No. 3.

* * * * *

## PART 810—OFFICIAL UNITED STATES STANDARDS FOR GRAIN

■ 3. Revise the authority citation for part 810 to read as follows:

**Authority:** 7 U.S.C. 71–87k.

■ 4. In § 810.102, revise paragraph (d) to read as follows:

### § 810.102 Definition of other terms.

* * * * *

(d) *Test Weight per bushel.* The weight per Winchester bushel (2,150.42 cubic inches) as determined using an approved device according to procedures prescribed in FGIS instructions. Test weight per bushel in the standards for corn, mixed grain, oats, sorghum, and soybeans is determined on the original sample. Test weight per bushel in the standards for barley, flaxseed, rye, sunflower seed, triticale, and wheat is determined after mechanically cleaning the original sample. Test weight per bushel is recorded to the nearest tenth pound for corn, rye, sorghum, soybeans, triticale, and wheat. Test weight per bushel for all other grains, if applicable, is recorded in whole and half pounds with a fraction of a half pound disregarded. Test weight per bushel is not an official factor for canola.

* * * * *

■ 5. In § 810.1402, revise paragraphs (c)(1) through (c)(3) and (h) to read as follows:

### § 810.1402 Definition of other terms.

* * * * *

(c) * * *

(1) *Sorghum.* Sorghum which lacks a pigmented testa (subcoat) and contains less than 98.0 percent White sorghum and not more than 3.0 percent Tannin sorghum. The pericarp color of this class may appear white, yellow, red, pink, orange or bronze.

(2) *Tannin sorghum.* Sorghum which has a pigmented testa (subcoat) and contains not more than 10 percent of kernels without a pigmented testa.

(3) *White sorghum.* Sorghum which lacks a pigmented testa (subcoat) and contains not less than 98.0 percent kernels with a white pericarp, and contains not more than 2.0 percent of sorghum of other classes. This class includes sorghum containing spots that, singly or in combination, cover 25.0 percent or less of the kernel.

* * * * *

(h) *Nongrain sorghum.* Seeds of broomcorn, Johnson-grass, *Sorghum almum* Parodi, and sudangrass; and seeds of Sorghum bicolor (L.) Moench that appear atypical of grain sorghum.

* * * * *

■ 6. Revise § 810.1404 to read as follows:

**§ 810.1404 Grades and grade requirements for sorghum.**

| Grading factors | Grades U.S. Nos. [1] | | | |
|---|---|---|---|---|
| | 1 | 2 | 3 | 4 |
| **Minimum pound limits of** | | | | |
| Test weight per bushel | 57.0 | 55.0 | 53.0 | 51.0 |
| **Maximum percent limits of** | | | | |
| Damaged kernels: | | | | |
| Heat (part of total) | 0.2 | 0.5 | 1.0 | 3.0 |
| Total | 2.0 | 5.0 | 10.0 | 15.0 |
| Broken kernels and foreign material: | | | | |
| Foreign material (part of total) | 1.0 | 2.0 | 3.0 | 4.0 |
| Total | 3.0 | 6.0 | 8.0 | 10.0 |
| **Maximum count limits of** | | | | |
| Other material: | | | | |
| Animal filth | 9 | 9 | 9 | 9 |
| Castor beans | 1 | 1 | 1 | 1 |
| Crotalaria seeds | 2 | 2 | 2 | 2 |
| Glass | 1 | 1 | 1 | 1 |
| Stones [2] | 7 | 7 | 7 | 7 |
| Unknown foreign substance | 3 | 3 | 3 | 3 |
| Cockleburs | 7 | 7 | 7 | 7 |
| Total [3] | 10 | 10 | 10 | 10 |

U.S. Sample grade is sorghum that:
(a) Does not meet the requirements for U.S. Nos. 1, 2, 3, or 4; or
(b) Has a musty, sour, or commercially objectionable foreign odor (except smut odor); or
(c) Is badly weathered, heating, or distinctly low quality.

[1] Sorghum which is distinctly discolored shall not grade higher than U.S. No. 3.
[2] Aggregate weight of stones must also exceed 0.2 percent of the sample weight.
[3] Includes any combination of animal filth, castor beans, crotalaria seeds, glass, stones, unknown foreign substance or cockleburs.

**David R. Shipman,**

*Acting Administrator, Grain Inspection, Packers and Stockyards Administration.*

[FR Doc. 07–3554 Filed 7–19–07; 8:45 am]

**BILLING CODE 3410–KD–P**

## NUCLEAR REGULATORY COMMISSION

## 10 CFR Part 171

## Annual Fees for Reactor Licenses and Fuel Cycle Licenses and Materials Licenses, Including Holders of Certificates of Compliance, Registrations, and Quality Assurance Program Approvals and Government Agencies Licensed by the NRC

*CFR Correction*

In Title 10 of the Code of Federal Regulations, Parts 51 to 199, revised as of January 1, 2007, in § 171.16, on page 742, paragraph (e) is reinstated to read as follows:

**§ 171.16 Annual fees: Materials licensees, holders of certificates of compliance, holders of sealed source and device registrations, holders of quality assurance program approvals, and government agencies licensed by the NRC.**

* * * * *

(e) The activities comprising the surcharge are as follows:

(1) LLW disposal generic activities;

(2) Activities not directly attributable to an existing NRC licensee or class(es) of licenses (e.g., international cooperative safety program and international safeguards activities; support for the Agreement State program; decommissioning activities for unlicensed sites; and activities for unregistered general licensees); and

(3) Activities not currently assessed licensing and inspection fees under 10 CFR part 170 based on existing law or Commission policy (e.g., reviews and inspections of nonprofit educational institutions and reviews for Federal agencies; activities related to decommissioning and reclamation; and costs that would not be collected from small entities based on Commission policy in accordance with the Regulatory Flexibility Act, 5 U.S.C. 601 *et seq.*).

[FR Doc. 07–55509 Filed 7–19–07; 8:45 am]

**BILLING CODE 1505–01–D**

## DEPARTMENT OF TRANSPORTATION

### Federal Aviation Administration

### 14 CFR Part 71

**[Docket No. FAA–2007–27594; Airspace Docket No. 07–ASO–3]**

## Establishment of Class D and E Airspace; Aguadilla, PR; Correction

**AGENCY:** Federal Aviation Administration (FAA), DOT.

**ACTION:** Correcting amendment.

**SUMMARY:** This document contains a correction to the final rule (FAA–2007–27594; 07–ASO–3), which was published in the **Federal Register** of May 8, 2007, (72 FR 25962), establishing Class D and E airspace at Aguadilla, PR. This action corrects errors in the summary and legal description for the Class E4 airspace at Aguadilla, PR.

**DATES:** *Effective Date:* Effective 0901 UTC, July 5, 2007. The Director of the Federal Register approves this incorporation by reference action under title 1, Code of Federal Regulations, part 51, subject to the annual revision of FAA Order 7400.9 and publication of conforming amendments.

**FOR FURTHER INFORMATION CONTACT:** Mark D. Ward, Manager, System Support Group, Eastern Service Center, Federal Aviation Administration, P.O. Box 20636, Atlanta, Georgia 30320; telephone (404) 305–5627.

**SUPPLEMENTARY INFORMATION:**

### Background

**Federal Register** Document 07–2250, Docket No. FAA–2007–27594; 07–ASO–3, published May 8, 2007, (72 FR 25962), establishes Class D and E4 airspace at Aguadilla, PR. Errors were discovered in the summary and legal description describing the Class E4 airspace area. In line 13 of the summary, Class E should read Class D. In the legal description for the Class E4 airspace, the navigation aid, Borinquen VORTAC, and geographical coordinates, Lat. 18°29′53″ N, long. 67°06′30″ W, were omitted. This action corrects those errors. Class E airspace designations for airspace areas designated as an extension to a Class D surface area are published in Paragraph 6004 of FAA Order 7400.9P, Airspace Designations and Reporting Points, dated September 1, 2006, and effective September 15, 2006, which is incorporated by reference in 14 CFR 71.1. The Class E airspace designation listed in this document will be published subsequently in the Order.

### Need for Correction

As published, the final rule contains errors in the summary and legal description of the Class E4 airspace area. Accordingly, pursuant to the authority delegated to me, the summary and legal description for the Class E4 airspace area at Aguadilla, PR, incorporated by reference at § 71.1, 14 CFR 71.1, and published in the **Federal Register** on May 8, 2007, (72 FR 25962), is corrected by making the following correcting amendment.

### List of Subjects in 14 CFR Part 71

Airspace, Incorporation by reference, Navigation (air).

■ In consideration of the foregoing, the Federal Aviation Administration corrects the adopted amendment, 14 CFR part 71, by making the following correcting amendment:

## PART 71—DESIGNATION OF CLASS A, CLASS B, CLASS C, CLASS D, AND CLASS E AIRSPACE AREAS; AIRWAYS; ROUTES; AND REPORTING POINTS

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

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

**§ 71.1 [Corrected]**

■ 2. The incorporation by reference in 14 CFR 71.1 of Federal Aviation Administration Order 7400.9P, Airspace Designations and Reporting Points, dated September 1, 2006, and effective September 15, 2006, is amended as follows:

*Paragraph 6004 Class E Airspace Areas Designated as an Extension to a Class D Surface Area.*

* * * * *

**ASO PR E4 Aguadilla, PR [Corrected]**

Rafael Hernandez Airport, PR
(Lat. 18°29′42″ N., long. 67°07′46″ W.)
Borinquen VORTAC
(Lat. 18°29′53″ N., long. 67°06′30″ W.)

That airspace extending upward from the surface within 2.4 miles each side of the Borinquen VORTAC 257° radial extending from the 4.5 mile radius to 7 miles west of the VORTAC. This Class E airspace area is effective during the specific days and times established in advance by a Notice to Airmen. The effective days and times will thereafter be continuously published in the Airport/Facility Directory.

* * * * *

On page 25962, column 2, line 13 of the Summary, correct the Class E and Class E4, changing ‘‘Class E and Class E4’’ to ‘‘Class D and E4’’.

* * * * *

Issued in College Park, Georgia, on April 26, 2007.

**Mark D. Ward,**

*Group Manager, System Support Group, Eastern Service Center.*

[FR Doc. 07–3503 Filed 7–19–07; 8:45 am]

**BILLING CODE 4910–13–M**

## DEPARTMENT OF THE TREASURY

### Internal Revenue Service

### 26 CFR Part 1

**[TD 9342]**

**RIN 1545–BE85**

## Guidance Under Section 1502; Amendment of Tacking Rule Requirements of Life-Nonlife Consolidated Regulations

**AGENCY:** Internal Revenue Service (IRS), Treasury.

**ACTION:** Final regulations and removal of temporary regulations.

**SUMMARY:** This document contains final regulations under section 1502 concerning the requirements for including insurance companies in a life-nonlife consolidated return. These regulations conform the consolidated return rules to certain changes in law. These regulations affect corporations filing life-nonlife consolidated returns.

**DATES:** *Effective Date:* These regulations are effective July 20, 2007.

*Applicability Date:* For dates of applicability, see §§ 1.1502–47(b) and 1.1502–76(d).

**FOR FURTHER INFORMATION CONTACT:** Ross Poulsen (202) 622–7790 or Marcie Barese (202) 622–7790 (not toll-free numbers).

**SUPPLEMENTARY INFORMATION:**

### Background

Section 1504(c) of the Internal Revenue Code permits life companies to join in the filing of a consolidated return with nonlife corporations with certain restrictions, the principal one of which is that a life company must be a member of the affiliated group (without regard to section 1504(b)(2)) for five taxable years before it may join in the filing of the consolidated group's return. Section 1.1502–47 contains an exception to this requirement (the tacking rule) for transactions that meet certain conditions. The original tacking rule contained five conditions, including ‘‘the separation condition.’’

Before 1981, section 843 required all insurance companies taxed under Subchapter L to adopt a calendar year tax year. The consolidated return regulations required all members of a consolidated group to adopt the tax year of the common parent, but, in order to accommodate section 843, required a fiscal-year consolidated group to change its tax year to a calendar year if, on the last day of its fiscal year, it included an insurance company required by section 843 to use a calendar year (Old § 1.1502–76(a)(2)). In 1981, an amendment to section 843 became effective, providing that, under regulations prescribed by the Secretary, an insurance company joining in the filing of a consolidated return may adopt the fiscal year of the common parent corporation.

On April 25, 2006, temporary regulations (TD 9258) were published in the **Federal Register** (71 FR 23856) amending the tacking rule of the life-nonlife consolidated return regulations and the regulations relating to taxable years of members of a consolidated group. A notice of proposed rulemaking (REG–133036–05) cross-referencing those temporary regulations was published in the **Federal Register** (71 FR 23882) on the same day. The temporary regulations removed the separation condition of the tacking rule and Old § 1.1502–76(a)(2).

On May 30, 2006, temporary regulations (TD 9264) were published in the **Federal Register** (71 FR 30591), in part, amending the regulations relating to taxable years of members of a consolidated group. A notice of proposed rulemaking (REG–134317–05) cross-referencing those temporary regulations was published in the **Federal Register** (71 FR 30640) on the same day. The temporary regulations eliminated impediments to the electronic filing of the statement made under § 1.1502–76(b)(2)(ii).

The IRS and Treasury Department considered several comments responding to the proposed and temporary regulations. After consideration of these comments, the final regulations adopt the provisions of the proposed regulations without substantive change and the corresponding temporary regulations are removed.

## Explanation and Summary of Comments

*Effective Date of § 1.1502–47*

The IRS received two comments from the public relating to the effective date of Prop. Reg. § 1.1502–47 and Temp. Reg. § 1.1502–47T. The proposed and temporary regulations are effective for taxable years for which the due date (without extensions) for filing returns is after April 25, 2006, (their date of publication). Several commentators noted that the preamble to the temporary regulations indicated that the purpose of the separation condition was largely eliminated in 1984 after Congress repealed the three phase system of life insurance company taxation, and it became even less relevant after Congress suspended taxation on distributions from policyholders surplus accounts made during 2005 and 2006. On that basis, these commentators requested that the effective date of the final regulations be applicable retroactively for all open tax years. While making this request, however, the commentators recognized that retroactive application of the regulations would present serious administrative concerns. The IRS and Treasury Department agree with the commentators that retroactive application of the final regulations raises significant questions of administrability. Therefore, in the interest of sound tax administration, the IRS and Treasury Department decline to adopt this suggestion.

Alternatively, the commentators requested that these final regulations be applicable for returns due after the effective date of the temporary regulations. We agree with this suggestion. Accordingly, the temporary regulations are applicable to returns due (without extensions) after April 25, 2006, and on or before the effective date of these final regulations. These final regulations are applicable to returns due (without extensions) after their effective date.

*Comments on Prop. Reg. § 1.1502–76 and Temp. Reg. § 1.1502–76T*

One commentator raised several concerns with the proposal to remove Old § 1.1502–76(a)(2). First, the commentator reads both the language of section 843 and the legislative history of the amendment to section 843 as demonstrating congressional intent to create a choice, when an insurance company joins a fiscal-year consolidated group, of whether the group remains on the fiscal year (requiring the joining insurance member to adopt the fiscal year) or adopts a calendar year tax year. Amended section 843 provides that (under regulations) an insurance company joining in the filing of a consolidated return ''may adopt'' the taxable year of the common parent corporation. The legislative history of amended section 843 acknowledges that ''[s]ome life companies may not want to adopt a [fiscal] year * * *.'' S. Rep. No. 94–938, at 455–56 (1976).

The IRS and Treasury Department do not agree with the commentator's interpretation of the statute or the legislative history. The election discussed in the legislative history is the election under section 1504(c) allowing a life company to join in the consolidated return of a nonlife group. The legislative history notes that ''[i]f this election is not made, existing law will continue to apply.'' The legislative history goes on to state:

> It is understood that although generally companies will probably desire to file consolidated returns with the life or other mutual insurance companies, some may choose to continue to file separate returns under existing law. Where this occurs, it is likely to arise from the fact that the parent corporation (whose year the other members joining in the filing of the consolidated return must follow) uses a fiscal year as its taxable year. Some life companies may not want to adopt a taxable year other than a calendar year since filings with State insurance commissioners are required by these life companies on a calendar year basis.

S. Rep. No. 94–938, at 455–56 (1976).

Rather than suggesting that the group has an election to change its taxable year when a newly-joining life company does not desire to adopt the group's fiscal year, the legislative history suggests that Congress expected, in such cases, that no section 1504(c) election would be made and the life company would continue filing separately. Further, the legislative history is clear that Congress amended section 843 in order to accommodate the consolidated return rules relating to taxable years of members of consolidated groups, not to modify or override them.

The sole purpose of Old § 1.1502–76(a)(2) was to conform the consolidated rules to section 843. Once section 843 was amended, not only was the purpose of Old § 1.1502–76(a)(2) eliminated, but Old § 1.1502–76(a)(2) was no longer operative because it only applies to groups with ''an includible insurance company required by section 843 to file its return on the basis of a calendar year * * *.'' For these reasons, the IRS and Treasury Department decline to create a regulatory election allowing fiscal-year consolidated groups to switch to a calendar year upon including an insurance company in its consolidated group.

Another comment noted that the legislative history of the amendment to section 843 contemplates that the Secretary will write regulations that require insurance companies adopting the fiscal year of a consolidated group to maintain adequate records reconciling all of the items on its fiscal year tax return with the corresponding items on its calendar year statements filed with State insurance commissioners. Since the amendment to section 843, the input received by the IRS and Treasury Department from taxpayers has not suggested a need for guidance in this area. However, the IRS and Treasury Department welcome comments on this topic.

The final comment suggested that a rule be added allowing an insurance company that joins a fiscal-year consolidated group and leaves the group before the end of the group's tax year to maintain its calendar year. The comment observed that, without such a rule, § 1.1502–76T(a) and section 843 create unnecessary work for such an insurance company because upon joining the group, the insurance company would be required to adopt the common parent's fiscal year under § 1.1502–76T(a)(1) and upon leaving the group, the insurance company would have to readopt a calendar year under section 843.

The IRS and Treasury Department decline to adopt this suggestion because they believe that the number of taxpayers affected by such a scenario would be too minimal to justify the creation of a special rule.

**Special Analyses**

It has been determined that this Treasury decision is not a significant regulatory action as defined in Executive Order 12866. Therefore, a regulatory assessment is not required. Pursuant to 5 U.S.C. 553(d)(3) it has been determined that a delayed effective date is unnecessary because this rule finalizes currently effective temporary rules regarding including life insurance companies in a life-nonlife consolidated return. It is hereby certified that these regulations will not have a significant economic impact on a substantial number of small entities. This certification is based on the fact that these regulations primarily affect affiliated groups of corporations with one or more life insurance company members, which tend to be larger businesses. Moreover, the number of taxpayers affected is minimal. Therefore, a Regulatory Flexibility Analysis under the Regulatory Flexibility Act (5 U.S.C. chapter 6) is not required. Pursuant to section 7805(f) of the Internal Revenue Code, the notice of proposed rulemaking preceding these regulations was submitted to the Chief Counsel for Advocacy of the Small Business Administration for comment on its impact on small business.

**Drafting Information**

The principal author of these regulations is Marcie Barese, Office of Associate Chief Counsel (Corporate). However, other personnel from the IRS and Treasury Department participated in their development.

**List of Subjects in 26 CFR Part 1**

Income taxes, Reporting and recordkeeping requirements.

**Adoption of Amendments to the Regulations**

■ Accordingly, 26 CFR part 1 is amended as follows:

## PART 1—INCOME TAXES

■ **Paragraph 1.** The authority citation for part 1 is amended by removing the entries for §§ 1.1502–47T and 1.1502–76T to read, in part, as follows:

**Authority:** 26 U.S.C. 7805 * * *

Section 1.1502–47 also issued under 26 U.S.C. 1502, 1503(c) and 1504(c). * * *

■ **Par. 2.** Section 1.1502–47 is amended by revising paragraphs (b)(2) and (d)(12)(v).

The revisions read as follows:

### § 1.1502–47 Consolidated returns by life-nonlife groups.

* * * * *

(b) * * *

(2) *Tacking rule effective dates*—(i) *In general.* Paragraph (d)(12)(v) of this section applies to any original consolidated Federal income tax return due (without extensions) after July 20, 2007.

(ii) *Prior law.* For original consolidated Federal income tax returns due (without extensions) after April 25, 2006, and on or before July 20, 2007, see § 1.1502–47T as contained in 26 CFR part 1 in effect on April 1, 2007. For original consolidated Federal income tax returns due (without extensions) on or before April 25, 2006, see § 1.1502–47 as contained in 26 CFR part 1 in effect on April 1, 2006.

* * * * *

(d) * * *

(12) * * *

(v) *Tacking rule.* The period during which an old corporation is in existence and a member of the group engaged in active business is included in (or tacks onto) the period for the new corporation if the following four conditions listed in this paragraph (d)(12)(v) are met. For purposes of this paragraph (d)(12)(v), a new corporation is a corporation (whether or not newly organized) during the period its eligibility depends upon the tacking rule. The four conditions are as follows—

(A) The first condition is that, at any time, 80 percent or more of the new corporation's assets it acquired (other than in the ordinary course of its trade or business) were acquired from the old corporation in one or more transactions described in section 351(a) or 381(a). This asset test is applied by using the fair market values of assets on the date they were acquired and without regard to liabilities. Assets acquired in the ordinary course of business will be excluded from total assets only if they were acquired after the new corporation became a member of the group (determined without section 1504(b)(2)). In addition, assets that the old corporation acquired from outside the group in transactions not conducted in the ordinary course of its trade or business are not included in the 80 percent (but are included in total assets) if the old corporation acquired those assets within five calendar years before the date of their transfer to the new corporation.

(B) The second condition is that at the end of the taxable year during which the first condition is first met, the old corporation and the new corporation must both have the same tax character. For purposes of this paragraph (d)(12), a corporation's tax character is the section under which it would be taxed (i.e., sections 11, 802, 821, or 831) if it filed a separate return. If the old corporation is not in existence (or adopts a plan of complete liquidation) at the end of that taxable year, this paragraph (d)(12)(v)(B) will apply to the old corporation's taxable year immediately preceding the beginning of the taxable year during which the first condition is first met.

(C) The third condition is that, at the end of the taxable year during which the first condition is first met, the new corporation does not undergo a disproportionate asset acquisition under paragraph (d)(12)(viii) of this section.

(D) The fourth condition is that, if there is more than one old corporation, the first two conditions apply to all of the corporations. Thus, the second condition (tax character) must be met by all of the old corporations transferring assets taken into account in meeting the test in paragraph (d)(12)(v)(A) of this section.

* * * * *

### § 1.1502–47T [Removed]

■ **Par. 3.** Section 1.1502–47T is removed.

■ **Par. 4.** Section 1.1502–76 is amended by revising paragraphs (a), (b)(2)(ii)(D), and (d).

The revisions read as follows:

**§ 1.1502–76 Taxable year of members of group.**

(a) *Taxable year of members of group.* The consolidated return of a group must be filed on the basis of the common parent's taxable year, and each subsidiary must adopt the common parent's annual accounting period for the first consolidated return year for which the subsidiary's income is includible in the consolidated return. If any member is on a 52–53-week taxable year, the rule of the preceding sentence shall, with the advance consent of the Commissioner, be deemed satisfied if the taxable years of all members of the group end within the same 7-day period. Any request for such consent shall be filed with the Commissioner of Internal Revenue, Washington, DC 20224, not later than the 30th day before the due date (not including extensions of time) for the filing of the consolidated return.

(b) * * *

(2) * * *

(ii) * * *

(D) *Election*—(*1*) *Statement.* The election to ratably allocate items under this paragraph (b)(2)(ii) must be made in a separate statement entitled, ''THIS IS AN ELECTION UNDER § 1.1502–76(b)(2)(ii) TO RATABLY ALLOCATE THE YEAR'S ITEMS OF [INSERT NAME AND EMPLOYER IDENTIFICATION NUMBER OF THE MEMBER].'' The election must be filed by including a statement on or with the returns including the items for the years ending and beginning with S's change in status. If two or more members of the same consolidated group, as a consequence of the same plan or arrangement, cease to be members of that group and remain affiliated as members of another consolidated group, an election under this paragraph (b)(2)(ii)(D)(*1*) may be made only if it is made by each such member. Each statement must also indicate that an agreement, as described in paragraph (b)(2)(ii)(D)(*2*) of this section, has been entered into. Each party signing the agreement must retain either the original or a copy of the agreement as part of its records. See § 1.6001–1(e).

(*2*) *Agreement.* For each election under this paragraph (b)(2)(ii), the member and the common parent of each affected group must sign and date an agreement. The agreement must—

(*i*) Identify the extraordinary items, their amounts, and the separate or consolidated returns in which they are included;

(*ii*) Identify the aggregate amount to be ratably allocated, and the portion of the amount included in the separate and consolidated returns; and

(*iii*) Include the name and employer identification number of the common parent (if any) of each group that must take the items into account.

* * * * *

(d) *Effective/applicability date*—(1) *Taxable years of members of group effective date.* (i) *In general.* Paragraph (a) of this section applies to any original consolidated Federal income tax return due (without extensions) after July 20, 2007.

(ii) *Prior law.* For original consolidated Federal income tax returns due (without extensions) after April 25, 2006, and on or before July 20, 2007, see § 1.1502–76T as contained in 26 CFR part 1 in effect on April 1, 2007. For original consolidated Federal income tax returns due (without extensions) on or before April 25, 2006, see § 1.1502–76 as contained in 26 CFR part 1 in effect on April 1, 2006.

(2) *Election to ratably allocate items effective date*—(i) *In general.* Paragraph (b)(2)(ii)(D) of this section applies to any original consolidated Federal income tax return due (without extensions) after July 20, 2007.

(ii) *Prior law.* For original consolidated Federal income tax returns due (without extensions) after May 30, 2006, and on or before July 20, 2007, see § 1.1502–76T as contained in 26 CFR part 1 in effect on April 1, 2007. For original consolidated Federal income tax returns due (without extensions) on or before May 30, 2006, see § 1.1502–76 as contained in 26 CFR part 1 in effect on April 1, 2006.

**§ 1.1502–76T [Removed]**

■ **Par. 5.** Section 1.1502–76T is removed.

**§ 1.502–35 [Amended]**

**§ 1.502–76 [Amended]**

■ **Par. 6.** For each entry in the ''Location'' column of the following table, remove the language in the ''Remove'' column and add the language in the ''Add'' column in its place:

| Location | Remove | Add |
|---|---|---|
| § 1.1502–35(c)(4)(ii)(B) | § 1.1502–76T(b)(2)(ii)(D) | § 1.1502–76(b)(2)(ii)(D). |
| § 1.1502–76(b)(2)(ii)(A)(*2*) | paragraph (b)(2)(ii)(D) of § 1.1502–76T | paragraph (b)(2)(ii)(D) of this section. |

**Kevin M. Brown,**

*Deputy Commissioner for Services and Enforcement.*

Approved: July 16, 2007.

**Eric Solomon,**

*Assistant Secretary of the Treasury (Tax Policy).*

[FR Doc. E7–14084 Filed 7–19–07; 8:45 am]

BILLING CODE 4830–01–P

## DEPARTMENT OF THE TREASURY

## Internal Revenue Service

## 26 CFR Part 301

**[TD 9344]**

**RIN 1545–BG24**

## Change to Office to Which Notices of Nonjudicial Sale and Requests for Return of Wrongfully Levied Property Must Be Sent

**AGENCY:** Internal Revenue Service (IRS), Treasury.

**ACTION:** Final and temporary regulations.

**SUMMARY:** This document contains final and temporary regulations relating to the discharge of liens under section 7425 and return of wrongfully levied upon property under section 6343 of the Internal Revenue Code (Code) of 1986. These temporary regulations clarify that such notices and claims should be sent to the IRS official and office specified in the relevant IRS publications. The temporary regulations will affect parties seeking to provide the IRS with notice of a nonjudicial foreclosure sale and parties making administrative requests for return of wrongfully levied property. The text of the temporary regulations also serves as the text of the proposed regulations set forth in the notice of proposed rulemaking on this subject in the Proposed Rules section in this issue of the **Federal Register**.

**DATES:** *Effective/applicability Date:* These regulations are effective August 20, 2007.

**FOR FURTHER INFORMATION CONTACT:** Robin M. Ferguson, (202) 622–3610 (not a toll-free call).

**SUPPLEMENTARY INFORMATION:**

## Background

This document contains amendments to the Procedure and Administration Regulations (26 CFR part 301) relating to the giving of notice of nonjudicial sales under section 7425(b) of the Code. Final regulations (TD 7430) were published on August 20, 1976, in the **Federal Register** (41 FR 35174). This document also contains amendments to the Procedure and Administration Regulations relating to requests for return of wrongfully levied property under section 6343(b) of the Code. Final regulations (TD 8587) were published on January 3, 1995, in the **Federal Register** (60 FR 33).

For notices of nonjudicial foreclosure sale under Section 7425(b) and requests for return of property wrongfully levied upon under Section 6343(b), the existing regulations direct the notices and requests to be sent to the ''district director (marked for the attention of the Chief, Special Procedures Staff).'' The offices of the district director and Special Procedures were eliminated by the IRS reorganization implemented pursuant to the IRS Restructuring and Reform Act of 1998, Public Law 105–206 (RRA 1998), creating uncertainty as to the timeliness of notices and requests under these provisions.

## Explanation of Provisions

Section 7425(b) provides for the discharge of a junior federal tax lien by a nonjudicial sale, if proper notice is provided to the IRS. Treas. Reg. § 301.7425–2(a). Notice of a nonjudicial sale is required if notice of the federal tax lien has been properly filed more than 30 days before the nonjudicial sale. Section 7425(b)(1). A party holding a nonjudicial sale must provide written notification to the IRS at least 25 days prior to the scheduled sale of the property or the federal tax lien remains on the property after the sale. Section 7425(c)(1). When the notice is properly sent, and the federal tax lien discharged, the IRS may redeem the property within 120 days from the date of sale or any longer period allowed under state law. Section 7425(d). If the notice is not properly sent, the nonjudicial sale is made subject to and without disturbing the federal tax lien. Section 7425(b); Treas. Reg. § 301.7425–2(a); *Tompkins* v. *United States,* 946 F.2d 817, 820 (11th Cir. 1991); *Simon* v. *United States,* 756 F.2d 696, 697–98 (9th Cir. 1985).

Treas. Reg. § 301.7425–3(a)(1) specifies that notice ''shall be given, in writing by registered or certified mail or by personal service * * * to the district director (marked for the attention of the chief, special procedures staff) for the Internal Revenue district in which the sale is to be conducted.'' The regulation further provides that such notice of sale is not effective if given to a district director other than the district director for the Internal Revenue district in which the sale is to be conducted.

In light of the IRS reorganization subsequent to RRA 1998, the district and special procedures offices referenced in the regulations no longer exist. Notices of sale, if addressed to an office other than that stated in the regulation, may be misdirected. As a result, the IRS office responsible for evaluating notices of nonjudicial sale may not receive notice of the sale and the IRS may not have the opportunity to timely redeem. In *Glasgow Realty, LLC* v. *Withington,* 345 F. Supp. 2d 1025 (E.D. Mo. 2004), the court held that the federal tax lien was discharged by a nonjudicial sale under section 7425(b) where the notice of sale was addressed to a local IRS taxpayer assistance center rather than the district director's office. *Glasgow Realty* demonstrates the confusion that resulted from attempts to comply with the current regulation in light of the IRS reorganization. An amendment is necessary to both assist the public so as to prevent further confusion on where to send notices of nonjudicial foreclosure sales, and to prevent the possible loss of proceeds that the IRS could acquire from redemptions if the proper office has timely notice of the sale.

Similar problems arise with respect to requests for return of wrongfully levied property under section 6343(b). Requests for the return of the amount of money levied upon or received from the sale of property must be filed within nine months from the date of the levy. Treas. Reg. § 301.6343–2(a)(2). The nine month period for filing a wrongful levy suit is extended by the filing of a timely administrative claim. Section 6532(c).

As is the case with notices of nonjudicial sale, the regulations specify that the request for return of wrongfully levied property be addressed to the district director (marked for the attention of the Chief, Special Procedures Staff) for the Internal Revenue district in which the levy is made. Treas. Reg. § 301.6343–2(b). The elimination of these offices by the IRS reorganization can similarly result in misdirected requests. An amendment is necessary to assist the public in filing timely requests with the proper office.

In order to account for the IRS's current organizational structure and to allow for future reorganizations of the IRS, the temporary regulations remove the title ''district director'' throughout Treas. Reg. §§ 301.7425–3 and 301.6343–2. The title is not replaced with any specific official or office. Instead, the public is directed to refer to the current relevant IRS publications or their successor publications for where to send notices or claims. The temporary regulations provide the web address for the IRS Internet site which may be used to obtain copies of IRS publications. The current publications for nonjudicial foreclosure sales are IRS Publication 786, ''Instructions for Preparing a Notice of Nonjudicial Sale of Property and Application for Consent to Sale,'' and IRS Publication 4235, ''Technical Services (Advisory) Group Addresses.'' According to Publication 786, the application or notice should be addressed to the Technical Services Group Manager for the area in which the notice of federal tax lien was filed. Publication 786 then instructs the reader to use Publication 4235 to determine where to mail the request. Publication 4235 lists the addresses for the Technical Services offices. The current publication for requests for return of wrongfully levied property is IRS Publication 4528, ''Making an Administrative Wrongful Levy Claim Under Internal Revenue Code (IRC) Section 6343(b).'' According to Publication 4528, the claim should be marked for the attention of the Advisory Territory Manager for the area where the taxpayer whose tax liability was the basis for the levy or seizure resides. Publication 4528 then instructs the reader to use Publication 4235 to locate the mailing address for the appropriate Advisory Territory Manager.

## Effective Date

These temporary regulations apply to any notice of sale filed or request for return of property made after August 20, 2007.

## Special Analyses

It has been determined that this Treasury decision is not a significant regulatory action as defined in Executive Order 12866. Therefore, a regulatory assessment is not required. For applicability of the Regulatory Flexibility Act, please refer to the cross-reference notice of proposed rulemaking published elsewhere in this **Federal Register**. Pursuant to section 7805(f) of the Internal Revenue Code, these regulations have been submitted to the

Chief Counsel for Advocacy of the Small Business Administration for comment on its impact on small business.

**Drafting Information**

The principal author of these regulations is Robin M. Ferguson, Office of Associate Chief Counsel, Procedure and Administration (Collection, Bankruptcy and Summonses Division).

**List of Subjects in 26 CFR Part 301**

Employment taxes, Estate taxes, Excise taxes, Gift taxes, Income taxes, Penalties, Reporting and recordkeeping requirements.

**Amendments to the Regulations**

■ Accordingly, 26 CFR part 301 is amended as follows:

## PART 301—PROCEDURE AND ADMINISTRATION

■ **Paragraph 1.** The authority citation for part 301 continues to read in part as follows:

**Authority:** 26 U.S.C. 7805 * * *

■ **Par. 2.** Section 301.6343–2 is amended as follows:
■ 1. Paragraphs (a)(1) introductory text and (b) introductory text are revised.
■ 2. Paragraphs (a)(4), (c), (d)(1), and (d)(2) are amended by removing the language ''director'' and adding the language ''IRS'' in its place wherever it appears.
■ 3. Paragraph (b)(4), is amended by removing the language ''Internal Revenue district'' and adding the language ''IRS office'' in its place.
■ 4. Paragraph (e) is revised.

The revisions and addition read as follows:

**§ 301.6343–2 Return of wrongfully levied upon property.**

(a) * * * (1) [Reserved]. For further guidance, See § 301.6343–2T(a) introductory text.

* * * * *

(b) [Reserved]. For further guidance, See § 301.6343–2T(b) introductory text.

* * * * *

(e) [Reserved]. For further guidance, See § 301.6343–2T(e).

■ **Par. 3.** Section 301.6343–2T is added to read as follows:

**§ 301.6343–2T Return of wrongfully levied upon property.**

(a) *Return of property*— (1) *General rule.* If the Internal Revenue Service (IRS) determines that property has been wrongfully levied upon, the IRS may return—

(a)(1)(i) through (a)(4) [Reserved]. For further guidance, see § 301.6343–2(a)(1)(i) through (a)(4).

(b) *Request for return of property.* A written request for the return of property wrongfully levied upon must be given to the IRS official, office and address specified in IRS Publication 4528, ''Making an Administrative Wrongful Levy Claim Under Internal Revenue Code (IRC) Section 6343(b),'' or its successor publication. The relevant IRS publications may be downloaded from the IRS Internet site at *http://www.irs.gov*. Under this section, a request for the return of property wrongfully levied upon is not effective if it is given to an office other than the office listed in the relevant publication. The written request must contain the following information—

(b)(1) through (d)(2) [Reserved]. For further guidance see § 301.6343–2(b)(1) through (d)(2).

(e) *Effective/applicability date.* This section applies to any request for return of wrongfully levied property that is filed after August 20, 2007.

■ **Par. 4.** Section 301.7425–3 is amended as follows:
■ 1. Paragraphs (a)(1), (b)(1), (b)(2), (c)(1), (d)(2), (d)(3), and (d)(4) are revised.
■ 2. Paragraphs (a)(2)(i), (a)(2)(ii)(C), and (a)(2)(iii) *Examples 1*, *2*, and *3* are amended by removing the language ''district director'' and adding the language ''IRS'' in its place wherever it appears.
■ 3. Paragraph (d)(1)(ii)(A) is amended by removing the language ''internal revenue district'' and adding the language ''IRS office'' in its place.
■ 4. Paragraph (e) is added.

The revisions and addition read as follows:

**§ 301.7425–3 Discharge of liens; special rules.**

(a) * * * (1) [Reserved]. For further guidance, See § 301.7425–3T(a)(1).

* * * * *

(b) * * * (1) [Reserved]. For further guidance, See § 301.7425–3T(b)(1).

* * * * *

(2) [Reserved]. For further guidance, See § 301.7425–3T(b)(2).

(c) * * * (1) [Reserved]. For further guidance, See § 301.7425–3T(c)(1).

* * * * *

(d) * * * (2) [Reserved]. For further guidance, See § 301.7425–3T(d)(2).

(3) [Reserved]. For further guidance, See § 301.7425–3T(d)(3).

(4) [Reserved]. For further guidance, See § 301.7425–3T(d)(4).

(e) [Reserved]. For further guidance, See § 301.7425–3T(e).

■ **Par. 5.** Section 301.7425–3T is added to read as follows:

**§ 301.7425–3T Discharge of liens; special rules.**

(a) *Notice of sale requirements*—(1) *In general.* Except in the case of the sale of perishable goods described in paragraph (c) of this section, a notice (as described in paragraph (d) of this section) of a nonjudicial sale shall be given, in writing by registered or certified mail or by personal service, not less than 25 days prior to the date of sale (determined under the provisions of § 301.7425–2(b)), to the Internal Revenue Service (IRS) official, office and address specified in IRS Publication 786, ''Instructions for Preparing a Notice of Nonjudicial Sale of Property and Application for Consent to Sale,'' or its successor publication. The relevant IRS publications may be downloaded from the IRS Internet site at *http://www.irs.gov*. Under this section, a notice of sale is not effective if it is given to an office other than the office listed in the relevant publication. The provisions of sections 7502 (relating to timely mailing treated as timely filing) and 7503 (relating to time for performance of acts where the last day falls on Saturday, Sunday, or a legal holiday) apply in the case of notices required to be made under this paragraph.

(a)(2) [Reserved]. For further guidance, see § 301.7425–3(a)(2).

(b) *Consent to sale*—(1) *In general.* Notwithstanding the notice of sale provisions of paragraph (a) of this section, a nonjudicial sale of property shall discharge or divest the property of the lien and title of the United States if the IRS consents to the sale of the property free of the lien or title. Pursuant to section 7425(c)(2), where adequate protection is afforded the lien or title of the United States, the IRS may, in its discretion, consent with respect to the sale of property in appropriate cases. Such consent shall be effective only if given in writing and shall be subject to such limitations and conditions as the IRS may require. However, the IRS may not consent to a sale of property under this section after the date of sale, as determined under § 301.7425–2(b). For provisions relating to the authority of the IRS to release a lien or discharge property subject to a tax lien, see section 6325 and the section 6325 regulations.

(2) *Application for consent.* Any person desiring the IRS's consent to sell property free of a tax lien or a title derived from the enforcement of a tax lien of the United States in the property shall submit to the IRS, at the office and address specified in the relevant IRS publications, a written application, in triplicate, declaring that it is made

under penalties of perjury, and requesting that such consent be given. The application shall contain the information required in the case of a notice of sale, as set forth in paragraph (d)(1) of this section, and, in addition, shall contain a statement of the reasons why the consent is desired.

(c) *Sale of perishable goodS*—(1) *In general.* A notice (as described in paragraph (d) of this section) of a nonjudicial sale of perishable goods (as defined in paragraph (c)(2) of this section) shall be given in writing, by registered or certified mail or delivered by personal service, at any time before the sale, to the IRS official and office specified in the relevant IRS publications, at the address specified in such publications. Under this section, a notice of sale is not effective if it is given to an office other than the office listed in the relevant publication. If a notice of a nonjudicial sale is timely given in the manner described in this paragraph, the nonjudicial sale shall discharge or divest the tax lien, or a title derived from the enforcement of a tax lien, of the United States in the property. The provisions of sections 7502 (relating to timely mailing treated as timely filing) and 7503 (relating to time for performance of acts where the last day falls on Saturday, Sunday, or a legal holiday) apply in the case of notices required to be made under this paragraph. The seller of the perishable goods shall hold the proceeds (exclusive of costs) of the sale as a fund, for not less than 30 days after the date of the sale, subject to the liens and claims of the United States, in the same manner and with the same priority as the liens and claims of the United States had with respect to the property sold. If the seller fails to hold the proceeds of the sale in accordance with the provisions of this paragraph and if the IRS asserts a claim to the proceeds within 30 days after the date of sale, the seller shall be personally liable to the United States for an amount equal to the value of the interest of the United States in the fund. However, even if the proceeds of the sale are not so held by the seller, but all the other provisions of this paragraph are satisfied, the buyer of the property at the sale takes the property free of the liens and claims of the United States. In the event of a postponement of the scheduled sale of perishable goods, the seller is not required to notify the IRS of the postponement. For provisions relating to the authority of the IRS to release a lien or discharge property subject to a tax lien, see section 6325 and the regulations.

(c)(2) through (d)(1) [Reserved]. For further guidance, see § 301.7425–3(c)(2) through (d)(1).

(d)(2) *Inadequate notice.* Except as otherwise provided in this paragraph, a notice of sale described in paragraph (a) of this section which does not contain the information described in paragraph (d)(1) of this section shall be considered inadequate by the IRS. If the IRS determines that the notice is inadequate, the IRS will give written notification of the items of information which are inadequate to the person who submitted the notice. A notice of sale which does not contain the name and address of the person submitting such notice shall be considered to be inadequate for all purposes without notification of any specific inadequacy. In any case where a notice of sale does not contain the information required under paragraph (d)(1)(ii) of this section with respect to a Notice of Federal Tax Lien, the IRS may give written notification of such omission without specification of any other inadequacy and such notice of sale shall be considered inadequate for all purposes. In the event the IRS gives notification that the notice of sale is inadequate, a notice complying with the provisions of this section (including the requirement that the notice be given not less than 25 days prior to the sale in the case of a notice described in paragraph (a) of this section) must be given. However, in accordance with the provisions of paragraph (b)(1) of this section, in such a case the IRS may, in its discretion, consent to the sale of the property free of the lien or title of the United States even though notice of the sale is given less than 25 days prior to the sale. In any case where the person who submitted a timely notice which indicates his name and address does not receive, more than 5 days prior to the date of sale, written notification from the IRS that the notice is inadequate, the notice shall be considered adequate for purposes of this section.

(3) *Acknowledgment of notice.* If a notice of sale described in paragraph (a) or (c) of this section is submitted in duplicate to the IRS with a written request that receipt of the notice be acknowledged and returned to the person giving the notice, this request will be honored by the IRS. The acknowledgment by the IRS will indicate the date and time of the receipt of the notice.

(4) *Disclosure of adequacy of notice.* The IRS is authorized to disclose, to any person who has a proper interest, whether an adequate notice of sale was given under paragraph (d)(1) of this section. Any person desiring this information should submit to the IRS a written request which clearly describes the property sold or to be sold, identifies the applicable notice of lien, gives the reasons for requesting the information, and states the name and address of the person making the request. The request should be submitted to the IRS official, office and address specified in IRS Publication 4235, ''Technical Services (Advisory) Group Addresses,'' or its successor publication. The relevant IRS publications may be downloaded from the IRS internet site at *http://www.irs.gov*.

(e) *Effective/applicability date.* This section applies to any notice of sale that is filed after August 20, 2007.

**Kevin M. Brown,**

*Deputy Commissioner for Services and Enforcement.*

Approved: July 11, 2007.

**Eric Solomon,**

*Assistant Secretary of the Treasury (Tax Policy).*

[FR Doc. E7–14053 Filed 7–19–07; 8:45 am]

**BILLING CODE 4830–01–P**

---

## DEPARTMENT OF DEFENSE

### Department of the Army

### 32 CFR Part 650

### Environmental Protection and Enhancement

**AGENCY:** Department of the Army, DoD.

**ACTION:** Final rule; removal.

**SUMMARY:** This action removes 32 CFR part 650, Environmental Protection and Enhancement, published in the **Federal Register**, December 29, 1977 (42 FR 65026). The rule is being removed because it is now obsolete and does not affect the general public.

**DATES:** Effective July 20, 2007.

**ADDRESSES:** Headquarters, Department of the Army, Office of the Assistant Chief of Staff for Installation Management, ATTN: DAIM–ED, 600 Army Pentagon, Washington, DC 20310–0600.

**FOR FURTHER INFORMATION CONTACT:** Mr. Douglas Warnock, (703) 601–1573.

**SUPPLEMENTARY INFORMATION:** The Office of the Assistant Chief of Staff for Installation Management, is the proponent for the regulation represented in 32 CFR part 650, and has concluded this regulation is obsolete. This regulation has been extensively revised and has been determined that the procedures prescribed in the regulation are for Army officials, and not intended to be enforced against any member of the public. As a result, the regulation does not affect the general public. Therefore, it would be helpful in avoiding confusion with the public if 32 CFR part 650, is removed.

**List of Subjects in 32 CFR Part 650**

Air pollution control, Environmental protection, Federal buildings and facilities, Hazardous substances, Historic preservation, Noise control, Waste treatment and disposal, Water pollution control.

## PART 650—[REMOVED]

■ Accordingly, for reasons stated in the preamble, under the authority of 10 U.S.C. 3012, 32 CFR part 650, *Environmental Protection and Enhancement*, is removed in its entirely.

**Brenda S. Bowen,**

*Army Federal Register Liaison Officer.*

[FR Doc. 07–3538 Filed 7–19–07; 8:45 am]

**BILLING CODE 3710–08–M**

## ENVIRONMENTAL PROTECTION AGENCY

### 40 CFR Part 52

**[EPA–R06–OAR–2006–0849; FRL–8442–8]**

### Approval and Promulgation of Implementation Plans; Louisiana; Clean Air Interstate Rule Sulfur Dioxide Trading Program

**AGENCY:** Environmental Protection Agency (EPA).

**ACTION:** Direct final rule.

**SUMMARY:** EPA is taking a direct final action to approve a revision to the Louisiana State Implementation Plan (SIP) submitted on September 22, 2006, enacted at Louisiana Administrative Code, Title 33, Part III, Chapter 5, Section 506(C) (LAC 33:III.506(C)). This revision addresses the requirements of EPA's Clean Air Interstate Rule (CAIR) Sulfur Dioxide ($SO_2$) Trading Program, promulgated on May 12, 2005 and subsequently revised on April 28, 2006. EPA is approving the SIP revision as fully implementing the CAIR $SO_2$ requirements for Louisiana. Therefore, as a consequence of this SIP approval, EPA will also withdraw the CAIR Federal Implementation Plan (CAIR FIP) concerning $SO_2$ emissions for Louisiana. The CAIR FIPs for all States in the CAIR region were promulgated on April 28, 2006 and subsequently revised on December 13, 2006.

CAIR requires States to reduce emissions of $SO_2$ and nitrogen oxides ($NO_X$) that significantly contribute to, and interfere with maintenance of, the national ambient air quality standards for fine particulates and/or ozone in any downwind state. CAIR establishes State budgets for $SO_2$ and $NO_X$ and requires States to submit SIP revisions that implement these budgets in States that EPA concluded did contribute to nonattainment in downwind states. States have the flexibility to choose which control measures to adopt to achieve the budgets, including participating in the EPA-administered cap-and-trade programs. In this SIP revision that EPA is approving, EPA finds that Louisiana meets CAIR $SO_2$ requirements by participating in the EPA-administered cap-and-trade program addressing $SO_2$ emissions.

The intended effect of this action is to reduce $SO_2$ emissions from the State of Louisiana that are contributing to nonattainment of the $PM_{2.5}$ National Ambient Air Quality Standard (NAAQS or standard) in downwind states. This action is being taken under section 110 of the Federal Clean Air Act (the Act or CAA).

**DATES:** This rule is effective on September 18, 2007 without further notice, unless EPA receives relevant adverse comment by August 20, 2007. If EPA receives such comment, EPA will publish a timely withdrawal in the **Federal Register** informing the public that this rule will not take effect.

**ADDRESSES:** Submit your comments, identified by Docket ID No. EPA–R06–OAR–2006–0849, by one of the following methods:

(1) *www.regulations.gov:* Follow the on-line instructions for submitting comments.

(2) *E-mail:* Mr. Jeff Robinson at *robinson.jeffrey@epa.gov.* Please also cc the person listed in the **FOR FURTHER INFORMATION CONTACT** paragraph below.

(3) *U.S. EPA Region 6 ''Contact Us'' Web site: http://epa.gov/region6/r6coment.htm.* Please click on ''6PD'' (Multimedia) and select ''Air'' before submitting comments.

(4) *Fax:* Mr. Jeff Robinson, Chief, Air Permits Section (6PD–R), at fax number 214–665–6762.

(5) *Mail:* Mr. Jeff Robinson, Chief, Air Permits Section (6PD–R), Environmental Protection Agency, 1445 Ross Avenue, Suite 1200, Dallas, Texas 75202–2733.

(6) *Hand or Courier Delivery:* Mr. Jeff Robinson, Chief, Air Permits Section (6PD–R), Environmental Protection Agency, 1445 Ross Avenue, Suite 1200, Dallas, Texas 75202–2733. Such deliveries are accepted only between the hours of 8:30 a.m. and 4:30 p.m. weekdays except for legal holidays. Special arrangements should be made for deliveries of boxed information.

*Instructions:* Direct your comments to Docket ID No. EPA–R06–OAR–2006–0849. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information the disclosure of which is restricted by statute. Do not submit information through *http://www.regulations.gov* or e-mail, if you believe that it is CBI or otherwise protected from disclosure. The *http://www.regulations.gov* Web site is an ''anonymous access'' system, which means that EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through *http://www.regulations.gov,* your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment along with any disk or CD–ROM submitted. 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 and any form of encryption and should be free of any defects or viruses. For additional information about EPA's public docket, visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm.*

*Docket:* All documents in the docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available, e.g., CBI or other information the disclosure of which is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the Air Permits Section (6PD–R), Environmental Protection Agency, 1445 Ross Avenue, Suite 700, Dallas, Texas 75202–2733. The file will be made available by appointment for public inspection in the Region 6 FOIA Review Room between the hours of 8:30 a.m. and 4:30 p.m. weekdays except for legal holidays. Contact the person listed in the **FOR FURTHER INFORMATION CONTACT** paragraph below to make an appointment. If possible, please make the appointment at least two working days in advance of your visit. A 15 cent per page fee will be charged for making photocopies of documents. On the day of the visit, please check in at the EPA Region 6 reception area on the seventh floor at 1445 Ross Avenue, Suite 700, Dallas, Texas.

The State submittal related to this SIP revision, and which is part of the EPA docket, is also available for public inspection at the State Air Agency listed below during official business hours by appointment:

Louisiana Department of Environmental Quality, Office of Environmental Quality Assessment, 602 N. Fifth Street, Baton Rouge, Louisiana 70802.

**FOR FURTHER INFORMATION CONTACT:** If you have questions concerning today's proposal, please contact Ms. Adina Wiley, Air Permits Section (6PD–R), Environmental Protection Agency, Region 6, 1445 Ross Avenue, Suite 1200, Dallas, TX 75202–2733. The telephone number is (214) 665–2115. Ms. Wiley can also be reached via electronic mail at *wiley.adina@epa.gov.*

**SUPPLEMENTARY INFORMATION:** Throughout this document wherever, any reference to ''we,'' ''us,'' or ''our'' is used, we mean EPA.

**Table of Contents**



## I. What Action Is EPA Taking?

EPA is taking direct final action to approve a revision to Louisiana's SIP, submitted on September 22, 2006, enacted at Louisiana Administrative Code, Title 33, Part III, Chapter 5, Section 506(C) (LAC 33:III.506(C)). In its SIP revision, Louisiana would meet CAIR $SO_2$ requirements by requiring certain electric generating units (EGUs) to participate in the EPA-administered CAIR cap-and-trade program addressing $SO_2$ emissions. The SIP as revised that EPA is approving meets the applicable requirements of CAIR. Our detailed analysis of this SIP revision is in the Technical Support Document (TSD) for the Louisiana CAIR $SO_2$ Trading Program. The TSD is available as specified in the section of this document identified as **ADDRESSES**. As a consequence of the SIP approval, the Administrator of EPA will also issue a final rule to withdraw the FIP concerning $SO_2$ emissions for Louisiana. This action will delete and reserve 40 CFR 52.985 in part 52. The withdrawal of the CAIR FIP for Louisiana is a conforming amendment that must be made once the SIP is approved because EPA's authority to issue the FIP was premised on a deficiency in the SIP for Louisiana. Once the SIP is fully approved, EPA no longer has authority for the FIP. Thus, EPA will not have the option of maintaining the FIP following the full SIP approval. Accordingly, EPA does not intend to offer an opportunity for a public hearing or an additional opportunity for written public comment on the withdrawal of the FIP.

We are publishing this rule without prior proposal because we view this as a noncontroversial amendment and anticipate no relevant adverse comments. However, in the proposed rules section of this **Federal Register** publication, we are publishing a separate document that will serve as the proposal to approve the SIP revision if relevant adverse comments are received. This rule will be effective on September 18, 2007 without further notice unless we receive relevant adverse comment by August 20, 2007. If we receive relevant adverse comments, we will publish a timely withdrawal in the **Federal Register** informing the public that the rule will not take effect. We will address all public comments in a subsequent final rule based on the proposed rule. We will not institute a second comment period on this action. Any parties interested in commenting must do so now. Please note that if we receive adverse comment on an amendment, paragraph, or section of this rule and if that provision may be severed from the remainder of the rule, we may adopt as final those provisions of the rule that are not the subject of an adverse comment.

## II. What Is the Regulatory History of CAIR and the CAIR FIPs?

The Clean Air Interstate Rule (CAIR) was published by EPA on May 12, 2005 (70 FR 25162). In this rule, EPA determined that 28 States and the District of Columbia contribute significantly to nonattainment and interfere with maintenance of the national ambient air quality standards (NAAQS) for fine particles ($PM_{2.5}$) and /or 8-hour ozone in downwind States in the eastern part of the country. As a result, EPA required those upwind States to revise their SIPs to include control measures that reduce emissions of $SO_2$, which is a precursor to $PM_{2.5}$ formation, and/or $NO_X$, which is a precursor to both ozone and $PM_{2.5}$ formation. For jurisdictions that contribute significantly to downwind $PM_{2.5}$ nonattainment, CAIR sets annual State-wide emission reduction requirements (i.e., budgets) for $SO_2$ and annual State-wide emission reduction requirements for $NO_X$. Similarly, for jurisdictions that contribute significantly to 8-hour ozone nonattainment, CAIR sets State-wide emission reduction requirements for $NO_X$ for the ozone season (defined at 40 CFR 97.302 as May 1st to September 30th). Under CAIR, States may implement these reduction requirements by participating in the EPA-administered cap-and-trade programs or by adopting any other control measures. Louisiana was found to significantly contribute to nonattainment of the $PM_{2.5}$ standard in Alabama and the 8-hour ozone standard in Texas, resulting in Louisiana being subject to the $SO_2$, annual $NO_X$, and ozone season $NO_X$ CAIR requirements.

CAIR explains to subject States what must be included in SIPs to address the requirements of section 110(a)(2)(D) of the Clean Air Act (CAA) with regard to interstate transport with respect to the 8-hour ozone and $PM_{2.5}$ NAAQS. EPA made national findings, effective on May 25, 2005, that the States had failed to submit SIPs meeting the requirements of section 110(a)(2)(D). The SIPs were due in July 2000, 3 years after the promulgation of the 8-hour ozone and $PM_{2.5}$ NAAQS. These findings started a 2-year clock for EPA to promulgate a Federal Implementation Plan (FIP) to address the requirements of section 110(a)(2)(D). Under CAA section 110(c)(1), EPA may issue a FIP anytime after such findings are made and must do so within two years unless a SIP revision correcting the deficiency is approved by EPA before the FIP is promulgated.

On April 28, 2006, EPA promulgated CAIR FIPs for all States covered by CAIR in order to ensure the emissions reductions required by CAIR are achieved on schedule. See 40 CFR 52.35 and 52.36. Each CAIR State is subject to the FIP until the State fully adopts, and EPA approves, a SIP revision meeting the requirements of CAIR. The CAIR FIPs require certain EGUs to participate in the EPA-administered CAIR $SO_2$, $NO_X$ annual, and $NO_X$ ozone season trading programs, as appropriate, found at 40 CFR part 97. The CAIR FIPs' $SO_2$, $NO_X$ annual, and $NO_X$ ozone season trading programs impose essentially the same requirements as, and are integrated with, the respective CAIR SIP trading programs. The integration of the CAIR FIP and SIP trading programs means that these trading programs will work together to create effectively a single trading program for each regulated pollutant ($SO_2$, $NO_X$ annual, and $NO_X$ ozone season) in all States covered by the CAIR FIPs' or SIPs' trading program for that pollutant. The CAIR FIPs also allow States to submit abbreviated SIP revisions that, if approved by EPA, will automatically replace or supplement certain CAIR FIP provisions, while the CAIR FIPs remain in place for all other provisions.

On April 28, 2006, EPA published two additional CAIR-related final rules that added the States of Delaware and New Jersey to the list of States subject to CAIR for $PM_{2.5}$ and announced EPA's final decisions on reconsideration of five issues, without making any substantive changes to the CAIR requirements. On December 13, 2006, EPA published minor, non-substantive revisions that serve to clarify CAIR and the CAIR FIPs.

## III. What Are the General Requirements of CAIR and the CAIR FIPs?

CAIR establishes State-wide emission budgets for $SO_2$ and $NO_X$ and is to be implemented in two phases. The first phase of $NO_X$ reductions starts in 2009 and continues through 2014, while the first phase of $SO_2$ reductions starts in 2010 and continues through 2014. The second phase of reductions for both $NO_X$ and $SO_2$ starts in 2015 and continues thereafter. CAIR requires States to implement the budgets by either: (1) Requiring EGUs to participate in the EPA-administered cap-and-trade programs; or (2) adopting other control measures of the State's choosing and demonstrating that such control measures will result in compliance with the applicable State $SO_2$ and $NO_X$ budgets.

The May 12, 2005 and April 28, 2006 CAIR rules provide model rules that States must adopt (with certain limited changes, if desired) if they want to participate in the EPA-administered trading programs. The December 13, 2006, revisions to CAIR and the CAIR FIPs were non-substantive and, therefore, do not affect EPA's evaluation of a State's SIP revision.

With two exceptions, only States that choose to meet the requirements of CAIR through methods that exclusively regulate EGUs are allowed to participate in the EPA-administered trading programs. One exception is for States that adopt the opt-in provisions of the model rules to allow non-EGUs individually to opt into the EPA-administered trading programs. The other exception is for States that include all non-EGUs from their $NO_X$ SIP Call trading programs in their CAIR $NO_X$ ozone season trading programs. Louisiana was not subject to the $NO_X$ SIP Call requirements; therefore this exception is not available to the State.

## IV. What Are the Types of CAIR SIP Submittals?

States have the flexibility to choose the type of control measures they will use to meet the requirements of CAIR. EPA anticipates that most States will choose to meet the CAIR requirements by selecting an option that requires EGUs to participate in the EPA-administered CAIR cap-and-trade programs. For such States, EPA has provided two approaches for submitting and obtaining approval for CAIR SIP revisions. States may submit full SIP revisions that adopt the model CAIR cap-and-trade rules. If approved, these SIP revisions will fully replace the State's CAIR FIPs. Alternatively, States may submit abbreviated SIP revisions. The provisions in the abbreviated SIP revision, if approved into a State's SIP, will not replace that State's CAIR FIP; however, the requirements for the CAIR FIPs at 40 CFR part 52 incorporate the provisions of the Federal CAIR trading programs in 40 CFR part 97. The Federal CAIR trading programs in 40 CFR part 97 provide that whenever EPA approves an abbreviated SIP revision, the provisions in the abbreviated SIP revision will be used in place of or in conjunction with, as appropriate, the corresponding provisions in 40 CFR part 97 of the State's CAIR FIP.

A State submitting a full SIP revision may either adopt regulations that are substantively identical to the model rules or incorporate by reference the model rules. CAIR provides that States may only make limited changes to the model rules if the States want to participate in the EPA-administered trading programs. A full SIP revision may change the model rules only by altering their applicability and allowance allocation provisions to:

(1) Include $NO_X$ SIP Call trading sources that are not EGUs under CAIR in the CAIR $NO_X$ Ozone Season Trading Program;

(2) Provide for State allocation of $NO_X$ annual or ozone season allowances using a methodology chosen by the State;

(3) Provide for State allocation of $NO_X$ annual allowances from the compliance supplement pool (CSP) using the State's choice of allowed, alternative methodologies; or

(4) Allow units that are not otherwise CAIR units to opt individually into the CAIR $SO_2$, $NO_X$ Annual, or $NO_X$ Ozone Season Trading Programs under the opt-in provisions in the model rules.

EPA's authority to issue the CAIR FIPs was premised on the deficiency of each State's SIP in addressing the CAIR requirements. EPA will not have the option of maintaining the CAIR FIP following approval of a full CAIR SIP revision. Therefore, an approved CAIR full SIP revision will replace the CAIR FIP requirements for $NO_X$ annual, $NO_X$ ozone season, or $SO_2$ emissions, as applicable, for that State.

## V. What Is EPA's Analysis of the Louisiana CAIR $SO_2$ SIP Submittal?

### *A. State Budget for $SO_2$ Allowance Allocations*

The CAIR State $SO_2$ budgets were derived by discounting the tonnage of emissions authorized by annual allowance allocations under the Acid Rain Program under title IV of the CAA. Under CAIR, each allowance allocated in the Acid Rain Program for the years in Phase 1 of CAIR (2010 through 2014) authorizes 0.5 ton of $SO_2$ emissions in the CAIR trading program, and each Acid Rain Program allowance allocated for the years in Phase 2 of CAIR (2015 and thereafter) authorizes 0.35 ton of $SO_2$ emissions in the CAIR trading program.

In today's action, EPA is approving Louisiana's SIP revision that incorporates by reference the $SO_2$ model trading rule as satisfying the budget requirements of 40 CFR 51.124(e). At 40 CFR 51.124(o)(1) we explain that any State that incorporates by reference the CAIR $SO_2$ trading program at subparts AAA through HHH of 40 CFR part 96, meets the budget obligation under 40 CFR 51.124(e). Therefore, Louisiana's SIP revision establishes the State CAIR $SO_2$ budgets as 59,948 tons of $SO_2$ emissions for 2010–2014 and 41,963 tons of $SO_2$ emissions in 2015 and thereafter. Louisiana's SIP revision sets these $SO_2$ budgets as the total amount of allowances available for allocation for a given year under the EPA-administered $SO_2$ cap-and-trade program.

### *B. CAIR $SO_2$ Cap-and-Trade Program*

The provisions of the CAIR $SO_2$ model rule are similar to the provisions of the CAIR $NO_X$ annual and ozone season model rules, which largely mirror the structure of the $NO_X$ SIP Call model trading rule in 40 CFR part 96, subparts A through I. However, the $SO_2$ model rule is coordinated with the ongoing Acid Rain $SO_2$ cap-and-trade program under CAA title IV. The $SO_2$

model rule uses the title IV allowances for compliance, with each allowance allocated for 2010–2014 authorizing only 0.50 ton of emissions and each allowance allocated for 2015 and thereafter authorizing only 0.35 ton of emissions. Banked title IV allowances allocated for years before 2010 can be used at any time in the CAIR $SO_2$ cap-and-trade program, with each such allowance authorizing 1 ton of emissions. Title IV allowances are to be freely transferable among sources covered by the Acid Rain Program and sources covered by the CAIR $SO_2$ cap-and-trade program.

EPA also used the CAIR $SO_2$ model trading rule as the basis for the $SO_2$ trading program in the CAIR FIPs. The CAIR FIPs' trading rules are virtually identical to the CAIR model trading rules, with changes made to account for federal rather than state implementation. The CAIR model $SO_2$ trading rules and the respective CAIR FIPs' trading rules are designed to work together as an integrated $SO_2$ trading program.

In the September 22, 2006, SIP revision, Louisiana chooses to implement its CAIR $SO_2$ budgets by requiring EGUs to participate in the EPA-administered cap-and-trade program for $SO_2$ emissions. Louisiana has adopted a full SIP revision that incorporates by reference the CAIR model cap-and-trade rule for $SO_2$ emissions as published at 40 CFR part 96, subparts AAA–HHH on July 1, 2005, and as revised at 70 FR 25162–25405, May 12, 2005, and 71 FR 25162–25405, April 28, 2006. This SIP revision does not include subpart III, CAIR $SO_2$ Opt-in Units, and any references to opt-in units. This SIP revision also does not include the December 13, 2006, revisions to the $SO_2$ trading rules in the CAIR and CAIR FIPs.

### *C. Individual Opt-In Units*

The opt-in provisions of the CAIR model trading rules allow certain non-EGUs (i.e., boilers, combustion turbines, and other stationary fossil-fuel-fired devices) that do not meet the applicability criteria for a CAIR trading program to participate voluntarily in (i.e., opt into) the CAIR trading program. A non-EGU may opt into one or more of the CAIR trading programs. In order to qualify to opt into a CAIR trading program, a unit must vent all emissions through a stack and be able to meet monitoring, recordkeeping, and reporting requirements of 40 CFR part 75. The owners and operators seeking to opt a unit into a CAIR trading program must apply for a CAIR opt-in permit. If the unit is issued a CAIR opt-in permit, the unit becomes a CAIR unit, is allocated allowances, and must meet the same allowance-holding and emissions monitoring and reporting requirements as other units subject to that CAIR trading program. The opt-in provisions provide for two methodologies for allocating allowances for opt-in units, one methodology that applies to opt-in units in general and a second methodology that allocates allowances only to opt-in units that the owners and operators intend to repower before January 1, 2015.

States have several options concerning the opt-in provisions. States may adopt the CAIR opt-in provisions entirely or may adopt them but exclude one of the methodologies for allocating allowances. States may also decline to adopt the opt-in provisions.

Louisiana has chosen not to allow non-EGUs to opt into the CAIR $SO_2$ trading program. Louisiana incorporated by reference the CAIR $SO_2$ Trading Program, published at 40 CFR part 96, subparts AAA–HHH on July 1, 2005, and as revised at 70 FR 25162–25405, May 12, 2005, and 71 FR 25162–25405, April 28, 2006. This SIP revision does not include subpart III, CAIR $SO_2$ Opt-in Units, and any references to opt-in units.

## VI. Final Action

We are approving Louisiana's CAIR $SO_2$ SIP revision submitted on September 22, 2006, enacted at LAC 33:III.506(C). Under this SIP revision, Louisiana is choosing to participate in the EPA-administered cap-and-trade program for $SO_2$ emissions. Our technical analysis has shown that this SIP revision is consistent with the requirements of 40 CFR part 51, including the specific CAIR $SO_2$ requirements at 40 CFR 51.124 as published on May 12, 2005, and further revised on April 28, 2006; and all applicable requirements of the CAA. While we are approving the Louisiana CAIR $SO_2$ SIP as satisfying the CAIR $SO_2$ requirements, it is important to note that the Louisiana SIP revision does not incorporate EPA's latest revisions to CAIR made on December 13, 2006, and any future revisions. We understand that Louisiana will routinely update its SIP to reflect this change and any future EPA actions on the CAIR $SO_2$ Trading Program.

As a consequence of this SIP approval, the Administrator of EPA will also issue, without providing an opportunity for a public hearing or an additional opportunity for written public comment, a final rule to withdraw the CAIR FIP concerning $SO_2$ emissions for Louisiana. This action will delete and reserve 40 CFR 52.985 in part 52.

## VII. Statutory and Executive Order Reviews

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 and because this action will not have a significant, adverse effect on the supply, distribution, or use of energy, 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 standard, and does not alter the relationship or the distribution of power and responsibilities established in the Act. The EPA interprets Executive Order 13045, ''Protection of Children from Environmental Health Risks and Safety Risks'' (62 FR 19885, April 23, 1997), as applying only to those regulatory actions that concern health or safety risks such that the analysis required under section 5–501 of the Executive

Order has the potential to influence the regulation. This rule is not subject to Executive Order 13045 because it approves a state program. Executive Order 12898 (59 FR 7629, February 16, 1994) establishes federal executive policy on environmental justice. Because this rule merely approves a state rule implementing a Federal standard, EPA lacks the discretionary authority to modify today's regulatory decision on the basis of environmental justice considerations.

In reviewing SIP submissions, EPA's role is to approve state choices, provided that they meet the criteria of the 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 SIP submission for failure to use VCS. It would thus be inconsistent with applicable law for EPA, when it reviews a SIP submission, to use VCS in place of a SIP submission that otherwise satisfies the provisions of the 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.*).

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**. 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. 804(2).

Under section 307(b)(1) of the CAA, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by September 18, 2007. 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 52

Environmental protection, Air pollution control, Intergovernmental relations, Nitrogen dioxide, Ozone, Particulate matter, Reporting and recordkeeping requirements, Sulfur oxides.

Dated: July 11, 2007.

**Lawrence Starfield,**

*Acting Regional Administrator, EPA Region 6.*

■ 40 CFR part 52 is amended as follows:

## PART 52—[AMENDED]

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

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

## Subpart T—Louisiana

■ 2. Section 52.970 is amended as follows:

■ a. In paragraph (c) the table entitled "EPA Approved Louisiana Regulations in the Louisiana SIP" is amended under Chapter 5—Permit Procedures, by adding in numerical order a new entry for "Section 506(c)".

■ b. In paragraph (e) the table entitled "EPA Approved Louisiana Nonregulatory Provisions and Quasi-Regulatory Measures" is amended by adding a new entry for the "Clean Air Interstate Rule Sulfur Dioxide Trading Program".

### § 52.970 Identification of plan.

* * * * *

(c) * * *

EPA APPROVED LOUISIANA REGULATIONS IN THE LOUISIANA SIP

| State citation | Title/subject | State approval date | EPA approval date | Comments |
|---|---|---|---|---|
| * * | * | * | * | * * |
| **Chapter 5—Permit Procedures** | | | | |
| * * | * | * | * | * * |
| Section 506(c) | Clean Air Interstate Rule Requirements—Annual Sulfur Dioxide. | 09/20/06 | 07/20/07, [Insert *FR* page number where document begins]. | Sections 506(A), (B), (D), and (E) NOT in SIP. |
| * * | * | * | * | * * |

* * * * *

(e) * * *

EPA APPROVED LOUISIANA NONREGULATORY PROVISIONS AND QUASI-REGULATORY MEASURES

| Name of SIP provision | Applicable geographic or non-attainment area | State submittal date/effective date | EPA approval date | Explanation |
|---|---|---|---|---|
| * * | * | * * | * | * |
| Clean Air Interstate Rule Sulfur Dioxide Trading Program. | Statewide | 09/22/06 | 07/20/07, [Insert *FR* page number where document begins] | Acid Rain Program Provisions NOT in SIP. |

[FR Doc. E7–14068 Filed 7–19–07; 8:45 am]

**BILLING CODE 6560–50–P**

## DEPARTMENT OF HEALTH AND HUMAN SERVICES

## Centers for Medicare & Medicaid Services

## 42 CFR Part 402

**[CMS–6146–F; CMS–6019–F]**

**RINS 0938–AM98; 0938–AN48**

## Medicare Program; Revised Civil Money Penalties, Assessments, Exclusions, and Related Appeals Procedures

**AGENCY:** Centers for Medicare & Medicaid Services (CMS), HHS.

**ACTION:** Final rule.

**SUMMARY:** This final rule establishes the procedures for imposing exclusions for certain violations of the Medicare program and is based on the procedures that the Office of Inspector General has published for civil money penalties, assessments, and exclusions under their delegated authority. Implementation of this final rule protects beneficiaries from persons (that is, health care providers and entities) found in noncompliance with Medicare regulations, and otherwise improves the safeguard provisions under the Medicare statute. This final rule also establishes procedures that enable a person targeted for exclusion from the Medicare program to request the Centers for Medicare & Medicaid Services to act on its behalf to recommend to the Inspector General that the exclusion from Medicare be waived due to hardship that would be placed on Medicare beneficiaries as a result of the person's exclusion.

**DATES:** *Effective Date:* This final rule is effective on August 20, 2007.

**FOR FURTHER INFORMATION CONTACT:** Joel Cohen, (410) 786–3349. Joe Strazzire, (410) 786–2775.

**SUPPLEMENTARY INFORMATION:**

### I. Background

*A. Statutory and Regulatory History*

Section 2105 of the Omnibus Budget Reconciliation Act of 1981 (Pub. L. 97–35) added section 1128A to the Social Security Act (the Act) to authorize the Secretary of Health and Human Services (HHS) to impose civil money penalties (CMPs), assessments, and exclusions from the Medicare program for certain persons (that is, health care facilities, practitioners, suppliers, or other entities) under certain circumstances. Exclusion provides the ultimate enforcement tool for agencies attempting to establish compliance with legal and program standards, and is used in addition to potential civil, criminal, and other administrative proceedings.

Since 1981, the Congress has significantly increased both the number and types of circumstances under which the Secretary may impose the exclusion of a person from the Medicare and State health care programs. The Secretary has delegated the authority for these provisions to either the Office of the Inspector General (OIG) or CMS (October 20, 1994 rule, 59 FR 52967). The exclusion authorities delegated to the OIG for the most part address fraud, misrepresentation, or falsification, while those that address noncompliance with programmatic or regulatory requirements are delegated to CMS. However, the OIG has the authority to impose exclusions and to prosecute cases involving exclusions that were delegated to CMS, if CMS and the OIG jointly determine it to be in the interest of economy, efficiency, or effective coordination of activities. The determination may be made either on a case-by-case basis, or for all cases brought under a particular listed authority.

In the December 14, 1998 **Federal Register** (63 FR 68687), we published a final rule entitled ''Medicare and Medicaid Program; Civil Money Penalties, Assessments, Exclusions, and Related Appeals Procedures.'' That rule set forth the procedures for pursuing civil money penalties (CMPs) and assessments, and added a new part 402 to title 42, chapter IV of the Code of Federal Regulations (CFR) to incorporate our CMP and assessment authorities. However, we did not address exclusions in that final rule. Instead, we reserved subpart C for exclusions so that we could incorporate the relevant regulations at a future date.

In the December 14, 1998 final rule, we indicated that our procedures for imposing the CMPs and assessment authorities delegated to CMS were based on the procedures that the OIG had delineated in 42 CFR part 1003. We also made the OIG's hearing and appeal procedures set forth in 42 CFR part 1005 applicable to the CMP, assessment, and exclusion authorities delegated to us.

In the July 23, 2004 **Federal Register** (69 FR 43956), we published a proposed rule entitled ''Medicare Program; Revised Civil Money Penalties, Assessments, Exclusions, and Related Appeals Procedures.'' This proposed rule would amend subpart C by establishing the procedures for imposing exclusions for certain violations of the Medicare program. The proposed rule would incorporate the general requirements and procedures that are common to the imposition of an exclusion from the Medicare program.

In the August 4, 2005 **Federal Register** (70 FR 44879), we published a proposed rule entitled ''Medicare Program; Revised Civil Money Penalties, Assessments, Exclusions and Related Appeals Procedures'' that would implement section 949 of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (MMA) (Pub. L. 108–173). Section 949 of the MMA amended section 1128(c)(3)(B) of the Act to indicate that ''[s]ubject to subparagraph (g), in the case of an exclusion under subsection (a), the minimum period of exclusion shall be not less than 5 years, except that, upon the request of the administrator of a Federal health care program (as defined in section 1128B(f)) who determines that the exclusion would impose a hardship on individuals entitled to benefits under Part A of title XVIII or enrolled under Part B of such title, or both, the Secretary may, after consulting with the Inspector General of the Department of Health and Human Services, waive the exclusion under subsection (a)(1), (a)(3), or (a)(4) with respect to that program in the case of an individual or entity that is the sole community physician or sole source of essential specialized services in the community.'' The Conference Agreement accompanying the MMA clarifies the intent of the statutory requirement that a hardship determination be made before a waiver is approved. In short, we proposed the general requirements and procedures that would allow certain providers and entities identified for exclusion from the Medicare program to request that we act on their behalf to recommend to the OIG that their exclusion from Medicare be waived because of a hardship that would result on Medicare beneficiaries. We also stated in this proposed rule our intent to respond to the public comments we received from the July 23, 2004 proposed rule and this proposed rule in a single final rule.

*B. Timelines for Publication of This Medicare Final Rule*

Section 902 of the MMA amended section 1871(a) of the Act and requires the Secretary, in consultation with the Director of the Office of Management and Budget, to establish and publish timelines for the publication of Medicare final rules based on the previous publication of a Medicare proposed or interim final rule. Section 902 of the MMA also states that the timelines for these rules may vary, but must not exceed 3 years after publication of the preceding proposed or interim final rule, except under exceptional circumstances.

This final rule finalizes provisions set forth in the July 23, 2004 and the August 4, 2005 proposed rules. In addition, this final rule will be published within the 3-year time limit imposed by section 902 of the MMA. Therefore, this final rule will be published in accordance with the Congress' intent for ensuring timely publication of final rules.

**II. Provisions of the Proposed Rules and Analysis and Responses to Public Comments**

*A. Provisions of the July 23, 2004 Proposed Rule*

This proposed rule would amend part 402, subpart C, (Exclusions) to incorporate the rules concerning exclusions associated with the CMP violations identified in part 402. Subpart C contains the general requirements and procedures that are common to the imposition of an exclusion from Medicare, Medicaid, and (where applicable) other Federal health care programs. (These regulations do not materially impact the hearing and appeals procedures currently available to any person on whom we could impose an exclusion.)

We proposed adding the following provisions under part 402 subpart C.

1. Basis and Purpose (Proposed § 402.200)

Section 402.200 provides the basis and purpose for the imposition of an exclusion from Medicare, Medicaid, and (where applicable) other Federal health care programs based on noncompliance with the respective provisions of part 402 subpart A, § 402.1(e). This subpart also sets forth the appeal rights of a person subject to exclusion, as well as the procedures for a person's reinstatement following an exclusion. (This subpart is based on § 1003.102, § 1003.105, § 1003.107, and § 1003.109 of the OIG's regulations.)

2. Length of Exclusion (Proposed § 402.205)

This section describes the duration of exclusion from Medicare, Medicaid, and (where applicable) other Federal health care programs for the applicable violation. Currently, there are four general categories for which violations may cause exclusions. These categories involve noncompliance with assignment billings, noncompliance with charge or service limits, failure to provide information, or improperly providing information.

Some exclusion provisions provide that the exclusion is imposed in accordance with section 1842(j)(2) of the Act, which provides for exclusion from participation in programs under the Act. These exclusions may not exceed 5 years. For these exclusion provisions, we propose using our discretion to set a duration for the exclusion, up to 5 years, after considering aggravating and mitigating circumstances as described in the July 23, 2004 proposed rule (69 FR 43956).

By contrast, many other exclusion provisions extend to all Federal health care programs, and do not address the minimum or maximum duration of the exclusion. Instead, they simply refer to applying the provisions of section 1128A of the Act or section 1128(c) of the Act for imposition of the exclusion. However, neither section 1128A of the Act, nor section 1128(c) of the Act, address the specific duration of an exclusion for any of the title XVIII exclusion provisions described in this proposed rule. Therefore, where the duration of an exclusion is not specifically addressed by statute for a specific exclusion provision, we proposed using our discretion to apply a time period we believed was justified, taking into account appropriate aggravating and mitigating factors that are described in the July 23, 2004 proposed rule (69 FR 43956).

While several provisions of title XVIII of the Act refer on their face only to CMPs, they also make cross-references to section 1128A of the Act, from which we assert that our exclusion authority derives. This is the case with both sections 1877 and 1882 of the Act. Each of these provisions incorporates by reference portions of section 1128A of the Act, articulating with specificity which section 1128A provisions are applicable. In each case, this includes section 1128A's exclusion authority (and, in the case of section 1877 of the Act, the exclusion authority is made even more clear with the term ''exclusion'' being found in the section heading). The applicable provision of section 1128A of the Act is the provision's last sentence, explicitly made applicable to all the foregoing, which provides that the Secretary ''may make a determination in the same [CMP] proceeding to exclude the person from participation in Federal health care programs.''

3. Factors Considered in Determining Whether To Exclude, and the Length of Exclusion (Proposed § 402.208)

The statute specifies the grounds for imposition of the various exclusions, but offers little detail regarding the adjudicatory processes inherent in administering them. Instead, the statute vests us with broad administrative discretion. We are sensitive to the fact that the nature of grounds for imposition of exclusions vary widely.

Proposed § 402.208 would provide the specific details of the aggravating and mitigating circumstances that may be considered. (This section is based on the corresponding OIG sections of 42 CFR parts 1001 and 1003.) We note that our application of aggravating and mitigating factors flows both as a natural result of a statutory scheme that contemplates exclusions of varying lengths, as well as the Secretary's rulemaking authority specified in section 1871 of the Act.

4. Scope and Effect of Exclusion (Proposed § 402.209)

Proposed § 402.209 would provide the general scope and effect of an exclusion. Generally, an excluded person may not directly or indirectly submit claims, or cause claims to be submitted, to the Medicare program. A person who submits (or causes to be submitted) claims during the course of an exclusion risks other possible sanctions, including civil and criminal liability. Medicare will not pay claims for beneficiaries who elect to see an excluded person, except, perhaps, for the first claim, which will be accompanied by a notification to the beneficiary that the person has been excluded from participation in Medicare, and that no further Medicare payments will be made on the beneficiary's behalf. (This section is based on criteria provided by the OIG in § 1001.1901.) We note in § 402.209(b)(3) that because in some cases the maximum exclusion time limit may preclude us from applying the specified prohibited conduct as the basis for denying reinstatement to the Medicare program, the fact that an excluded person has engaged in prohibited conduct may give rise to a new exclusion action by the initiating agency (CMS or OIG) that will have the practical effect of denying the person reinstatement into the Medicare program.

5. Notice of Exclusion (Proposed § 402.210)

Proposed § 402.210 would specify the contents of respective notices and specifically, the timing for release of—(1) the written notice of intent to exclude (that is, the proposed determination); and (2) the written notice of exclusion. At a minimum, the written notice of intent to exclude provides the person with information as to the reason why it is noncompliant with the statute, the length of the proposed exclusion, and instructions for responding to the notice, including providing argument against exclusion for the agency to consider. The written notice to exclude is sent to the person in the same manner as the written notice of intent to exclude if the agency determines that the exclusion is warranted. This notice would also provide the person with information on its appeal rights regarding the exclusion. (This section is based on criteria provided by the OIG in § 1001.2001, § 1001.2002, § 1001.2004, and § 1003.109.)

6. Response to Notice of Proposed Exclusion (Proposed § 402.212)

Proposed § 402.212 would state the general process and procedure for a person to follow when presenting an oral or written response to the notice of intent to exclude (that is, the proposed determination). We would accept for consideration any supportive information the person provides. We would not limit nor suggest what type of information should be presented. The burden to present convincing information is left to the person's discretion. Even though this section is based on the process and procedures delineated by the OIG in § 1003.109, to encourage timely communication between the person and the initiating agency, we have added an additional element whereby the initiating agency would contact the person within 15 days of receipt of the person's request to establish a mutually agreed upon time and place for the oral presentation and discussion.

7. Appeal of Exclusion (Proposed § 402.214)

Proposed § 402.214 would specify the general appeal process for requesting a hearing before an administrative law judge, and details the required elements of the written request for appeal. (This section is based on criteria provided by the OIG in § 1005.) Generally, the elements of the written request must include the basis for the disagreement with the exclusion, the general basis for the person's defense, and reasons why the proposed length of exclusion should be modified. (This section is based on criteria provided by the OIG in § 1001.2003 and § 1001.2007.)

8. Request for Reinstatement (Proposed § 402.300)

In proposed § 402.300, we specified the request for reinstatement. In § 402.300(a), we described the written request for reinstatement. We stated that an excluded person may submit a written request for reinstatement to the initiating agency no sooner than 120 days prior to the terminal date of exclusion as specified in the notice of exclusion. The written request for reinstatement would be required to include documentation demonstrating that the person has met the standards set forth in § 402.302. We also state that obtaining or reactivating a Medicare provider number (or equivalent) would not constitute reinstatement.

Proposed § 402.300(b) would specify that, upon receipt of a written request for reinstatement, the initiating agency may require the person to furnish additional, specific information and authorization to obtain information from private health insurers, peer review organizations, and others, as necessary, to determine whether reinstatement is granted.

In § 402.300(c), we would state that failure to submit a written request for reinstatement or to furnish the required information or authorization would result in the continuation of the exclusion, unless the exclusion has been in effect for 5 years. In that case, reinstatement would be automatic.

Proposed § 402.300(d) specifies that, if a period of exclusion is reduced on appeal (regardless of whether further appeal is pending), the excluded person would be permitted to request and apply for reinstatement within 120 days of the expiration of the reduced exclusion period. A written request for the reinstatement would include the same standards specified in § 402.300(b). (This section is based on criteria provided by the OIG in § 1001.3001.)

9. Basis for Reinstatement (Proposed § 402.302)

In proposed § 402.302, we would specify that the initiating agency would authorize reinstatement if the agency determines that—(1) The period of exclusion has expired; (2) there are reasonable assurances that the types of actions that formed the basis for the original exclusion will not recur; and (3) there is no additional basis under title XVIII of the Act that will justify the continuation of the exclusion.

We also stated that the initiating agency would not authorize reinstatement if the basis for denying reinstatement lies in an excluded person continuing either to submit claims (or causing claims to be submitted) or to receive and accept payments from the Medicare program for items or services it has furnished, ordered, or prescribed. This section would apply, regardless of whether the excluded person has obtained a Medicare provider number (or equivalent), either as an individual or as a member of a group, before being reinstated.

In making a determination regarding reinstatement, the initiating agency would consider—(1) The conduct of the excluded provider occurring before the date of the notice of the exclusion, if that conduct was not known to the initiating agency at the time of the exclusion; (2) the conduct of the excluded person after the date of the exclusion; (3) whether all fines and all debts due and owing (including overpayments) to any Federal, State, or local government that relate to Medicare, Medicaid, or (where applicable) any Federal, State, or local health care program were paid in full, or alternatively that satisfactory arrangements were made to fulfill these obligations; (4) whether the excluded person complied with, or had made satisfactory arrangements to fulfill, all of the applicable conditions of participation or conditions of coverage under the Medicare statutes and regulations; and (5) whether the excluded person had, during the period of exclusion, submitted claims (or caused claims to be submitted) or payment to be made by Medicare, Medicaid, and (where applicable) any other Federal health care program for items or services furnished, ordered, or prescribed, and the conditions under which these actions occurred.

We proposed that reinstatement would not be effective until the initiating agency grants the request and provides notice under § 402.304. Reinstatement would be effective as provided in the notice. A determination for a denial of reinstatement will not be appealable or reviewable, except as provided in § 402.306.

We also proposed that an ALJ cannot require reinstatement of an excluded person according to this chapter as specified in § 402.306(d). (The content of this section is based on the criteria provided by the OIG in § 1001.3002.)

10. Approval of Request for Reinstatement (Proposed § 402.304)

With regard to approval of a request for reinstatement (§ 402.304), we would state that, if the initiating agency grants a request for reinstatement, then the initiating agency would—(1) Give written notice to the excluded person specifying the date of reinstatement; and (2) notify appropriate Federal and State agencies, and, to the extent possible, all others that were originally notified of the exclusion, that the person has been reinstated into the Medicare program.

A determination by the initiating agency to reinstate an excluded person would have no effect if Medicare, Medicaid, or (where applicable) any other Federal health care program has imposed a longer period of exclusion under its own authorities. (The content of this section is based on the procedures provided by the OIG in § 1001.3003.)

11. Denial of Request for Reinstatement (Proposed § 402.306)

In proposed § 402.306, we specified that if a request for reinstatement is denied, the initiating agency would provide written notice to the excluded person. Within 30 days of the date of this notice, the excluded person may submit to the initiating agency: (1) Documentary evidence and a written argument challenging the reinstatement denial; or (2) a written request to present written evidence or oral argument to an official of the initiating agency.

If this written request is received timely by the initiating agency, the initiating agency, within 15 days of receipt of the excluded provider or entity's request, would initiate communication with the excluded person to establish a time and place for the requested meeting.

After evaluating any additional evidence submitted by the excluded person (or at the end of the 30-day period described above, if no documentary evidence or written request was submitted), the initiating agency would send written notice to the excluded person either confirming the denial, or approving the reinstatement as set forth in proposed § 402.304. If the initiating agency elects to uphold its denial decision, the written notice would also indicate that a subsequent request for reinstatement would not be considered until at least 1 year after the date of the written denial notice.

The decision to deny reinstatement would not be subject to administrative review. (The content of this section is based on the procedures provided by the OIG in § 1001.3004.)

We received 11 comments related to the July 23, 2004 proposed rule. The following is a summary of the comments received and our responses to them.

*Comment:* Commenters expressed concern over the discretion that we may apply in setting the duration of exclusion when duration is not addressed by statute.

*Response:* The statute does not specifically set the duration of exclusion. Therefore, we will consider any and all factors, as listed in § 402.208, presented when weighing our decision on the length of the exclusion. We believe the circumstances and facts presented will provide a basis for determining the appropriate duration on a case-by-case basis.

*Comment:* Commenters stated that wrongful conduct that occurred at a time otherwise barred by the statute of limitations should not be considered as a factor.

*Response:* It is our intent to consider any and all applicable factors in making a determination of exclusion from the Medicare program, including past wrongful conduct unrelated to the specific conduct at issue. Unlike the imposition of civil monetary penalties that are only applied to the conduct at issue, we take a different position on imposing an exclusion from the Medicare program.

*Comment:* One commenter indicated the financial loss to the program associated as an aggravating or mitigating factor was too small. The commenter used as an example a single hospital claim whereby the value of a single claim is typically more than the loss proposed in the rule.

*Response:* We have drafted this final rule to be adopted as a generic template to account for all types of healthcare providers (for example, hospitals, physicians, and suppliers). The financial factors proposed for aggravating and mitigating circumstances provide us with the ability to consider a low dollar tolerance that would be applicable to both institutional and non-institutional providers.

*Comment:* One commenter suggested that instead of considering it a mitigating factor when the noncompliance resulted from an unintentional or unrecognized error in a request for payment, and the person took prompt corrective steps once the error was discovered, that this circumstance should mean that no exclusion was warranted.

*Response:* The circumstances described by the commenter would most likely result in a favorable determination. We would likely consider those particular circumstances as mitigating factors. We will look at all factors and degrees of timeliness and promptness of changing the noncompliant activity before rendering a determination on whether to exclude a person from the Medicare program and the duration of the exclusion period.

*Comment:* One commenter suggested adding as a mitigating circumstance the fact that the person has an effective compliance program in place.

*Response:* We agree that an effective compliance program could be considered a mitigating circumstance under § 402.208(b)(3). However, the compliance program would not be considered effective if a violation occurred during the time the program was in effect, and the violation was not identified and remedied by the person prior to CMS identifying the noncompliance. The remedial step of establishing an effective compliance program may result in the period of exclusion being modified.

*Comment:* One commenter questioned the knowledge of furnishing services at the request of or direction of an excluded person, and whether, for example, a hospital has any obligation to check the list of excluded persons when furnishing services at the request of another entity.

*Response:* We believe the exceptions described in § 402.209 address how we view the knowledge factor. With regard to an obligation to check the list of excluded persons, we are not aware of any statutory requirement of this type. While it is not obligatory to check the exclusions list, a provider may wish to voluntarily add this element as part of its compliance program to ensure that all claims for services of this type will be paid.

*Comment:* One commenter regarded the provision that the exclusion effective date would not be delayed if an appeal was filed timely would deprive the person of economic existence. Therefore, the commenter recommended that the exclusion be stayed until the appeal process had been concluded.

*Response:* As specified in § 402.210(a), before written notice of the exclusion is sent, the person would receive a notice of proposed determination. The person has the opportunity at this time to present to CMS documentary evidence and a written response, or to make an oral presentation as to why the exclusion should not be imposed. In response, we may not impose the exclusion if we find that the exclusion is unwarranted. Although the commenter may feel that the appeal process is unfair because the exclusion is not delayed, we intend to remain consistent with the process that governs the other Federal agencies.

*Comment:* One commenter suggested removing or revising the requirement of providing additional information when applying for reinstatement, because that requirement is too onerous, or the additional information requested may include protected information.

*Response:* If we request additional information, it is the excluded person's decision whether to provide the information. A person who seeks reinstatement should be prepared to provide evidence it deems appropriate to support the reinstatement as defined in § 402.302. However, we would base our determinations on the information that we have been provided.

*Comment:* One commenter requested that the provision regarding our upholding the initial appeal determination to deny reinstatement should have appeal rights.

*Response:* In reviewing the provision, the excluded person has two opportunities to present evidence to CMS that may meet the conditions for reinstatement as set forth in § 402.302. These two opportunities to present evidence are detailed in § 402.300(a) and § 402.306(a). Failing to present convincing evidence, the excluded person is again afforded the opportunity 1 year later, as detailed in § 402.306(c). We believe these situations provide an excluded person with adequate opportunity to be heard, and decline to add additional appeal rights.

*Comment:* One commenter expressed that there was conflict between § 402.210(a) and § 402.212(b) regarding the time period for submitting a request for oral argument.

*Response:* We reviewed the provisions and have revised the time period in § 402.212(b) to be consistent with the 30-day period in § 402.210(a) for submitting a request to present oral arguments.

*Comment:* One commenter suggested that the exclusions related to the provisions of section 1882 of the Act are not intended for issuers of Medigap insurance or Medigap insurance policies. The commenter suggested that the Congress did clearly apply civil monetary penalties to the provisions, but made no explicit application or reference to exclusions.

*Response:* As we discussed previously, section 1882 of the Act cross references section 1128A of the Act, articulating with specificity the applicable portions of the latter statute, which in each case includes section 1128A's exclusion authority. We believe that we have the legal authority to impose exclusions associated with violations of section 1882 of the Act.

*B. Provisions of the August 4, 2005 Proposed Rule*

This proposed rule would amend part 402, subpart C, (Exclusions) to set forth the general requirements and procedures that would allow persons targeted for exclusion from the Medicare program to request that CMS act on their behalf to recommend to the Inspector General that their exclusion from Medicare be waived because of a hardship that would result on Medicare beneficiaries. These requirements and procedures implement section 949 of the MMA.

We proposed adding the following provisions under subpart C:

1. Waiver of Exclusions (Proposed § 402.308)

In § 402.308, we stated that persons who have been excluded by the Inspector General may request that CMS act on their behalf to recommend to the Inspector General that their exclusion from the Medicare program be waived. We would recommend waiver if we determine that the person's exclusion from the Medicare program would place a hardship on Medicare beneficiaries. Our decision to make the recommendation of a waiver to the Inspector General is not subject to administrative or judicial review. Additionally, our recommendation of waiver is not tantamount to the automatic granting of a waiver, because it is the Inspector General who will make the final decision on whether a waiver should be granted to the excluded person.

We received 2 comments related to the August 4, 2005 proposed rule (CMS–6019–P). Below is a summary of the comments received and our responses to them.

*Comment:* One commenter indicated it was unable to identify the delegation of section 949 of the MMA waiver authority from the Secretary to the OIG; therefore, the commenter is opposed to the delegation.

*Response:* Our authority to request a waiver under section 949 of the MMA is specified in § 402.209 of this final rule. The authority of the OIG to grant or deny a request for a waiver is outside the scope of this final rule.

*Comment:* One commenter requested that we provide a definition with greater clarity for the terms used to describe persons eligible for the exclusion waiver.

*Response:* We have revised § 402.308(a) to refer to § 1001.2 of the OIG regulations, which define ''sole community physician'' and ''sole source of essential specialized services'' in the Medicare community.

**III. Provisions of the Final Regulations**

We are adopting all of the provisions of the proposed rules as final with the following changes.

Due to a typographical error, we are replacing § 402.105(d)(2)(xix) with § 402.105(d)(2)(ix).

In § 402.308, we are adding the terms ''sole community physician'' and ''sole source of essential specialized services in the community'' to the list of definitions. For each term, we are referencing those terms as they are defined by the OIG regulations at § 1001.2. In addition, in § 402.308(b), we are revising the text, ''For purposes of this part'' to read as ''For purposes of this subpart''.

## IV. Collection of Information Requirements

Under the Paperwork Reduction Act of 1995, we are required to provide 30-day notice in the **Federal Register** and solicit public comment before a collection of information requirement is submitted to the Office of Management and Budget (OMB) for review and approval. In order to fairly evaluate whether an information collection should be approved by OMB, section 3506(c)(2)(A) of the Paperwork Reduction Act of 1995 requires that we solicit comment on the following issues:

- The need for the information collection and its usefulness in carrying out the proper functions of our agency.
- The accuracy of our estimate of the information collection burden.
- The quality, utility, and clarity of the information to be collected.
- Recommendations to minimize the information collection burden on the affected public, including automated collection techniques.

*Scope and Effect of Exclusion (§ 402.209)*

Section 402.209(c)(2) states that payment may be made for certain emergency items or services furnished by an excluded person, or under the medical direction or on the request of an excluded person during the period of exclusion. In order to be paid, a claim for the emergency items or services must be accompanied by a sworn statement of the person furnishing the items or services, specifying the nature of the emergency and the reason that the items or services were not furnished by a person eligible to furnish or order the items or services.

The burden associated with this requirement is the time and effort associated with drafting and submitting a document containing a sworn statement that explains the circumstances under which services were furnished by an excluded individual. While this requirement does impose a burden, we believe it is exempt from the PRA as defined in 5 CFR 1320.4; information collected during the conduct of a criminal investigation or civil action or during the conduct of an administrative action, investigation, or audit involving an agency against specific individuals or entities is not subject to the PRA.

*Response to Notice of Proposed Determination to Exclude (§ 402.212).*

Section 412.212 outlines the procedures an individual must follow to submit a response to the notice of intent to exclude. Specifically, § 402.212(a) states that within 60 days of the receipt of the notice, a person may present to the initiating agency a written response to dispute whether the proposed exclusion is appropriate. In addition, the person submitting the written response to the notice may provide additional supportive documentation. The burden associated with this requirement is the time and effort associated with drafting and submitting a written response to the notice.

Section 402.212(b) states that recipient of a notice of intent to exclude is also afforded an opportunity to be heard by the initiating agency in order to make an oral presentation concerning whether the proposed exclusion is warranted. The person must submit the request for an oral presentation within 60 days of the receipt of the notice. The burden associated with this requirement is the time and effort associated with submitting a request for an oral presentation.

While the requirements listed in § 402.212(a) and (b) do impose burdens, we believe they are exempt from the PRA as defined in 5 CFR 1320.4; information collected during the conduct of a criminal investigation or civil action or during the conduct of an administrative action, investigation, or audit involving an agency against specific individuals or entities is not subject to the PRA.

*Appeal of Exclusion (§ 402.214)*

Section 402.214(b) lists the conditions under which an excluded person may file a request for a hearing before an administrative law judge (ALJ). Section 402.214(d) states that an excluded person must file a request for a hearing within 60 days from the receipt of the notice of exclusion. Section 402.214(e) lists the required content of the written request for a hearing.

The burden associated with these requirements is the time and effort necessary to draft and submit a request for a hearing with an ALJ as stated in § 402.214(d). In addition, the person must ensure that the request contains all of the information outlined in § 402.214(e). While these requirements do impose burdens, we believe they are exempt from the PRA as defined in 5 CFR 1320.4; information collected during the conduct of a criminal investigation or civil action or during the conduct of an administrative action, investigation, or audit involving an agency against specific individuals or entities is not subject to the PRA.

*Request for Reinstatement (§ 402.300)*

Section 402.300(a) explains that an excluded person may submit a request for reinstatement to the agency initiating the exclusion. An excluded person must submit a written request no sooner than 120 days prior to the terminal date of exclusion as specified in the notice of exclusion. Section 402.300(d) explains the request for reinstatement process for an excluded person that had the period of exclusion reduced on appeal. The excluded person must submit a written request and apply for reinstatement within 120 days of the expiration date of the reduced exclusion period.

The burden associated with these requirements is the time and effort necessary to draft and submit the request for reinstatement and to apply for reinstatement. While these requirements do impose burdens, we believe they are exempt from the PRA as defined in 5 CFR 1320.4; information collected during the conduct of a criminal investigation or civil action or during the conduct of an administrative action, investigation, or audit involving an agency against specific individuals or entities is not subject to the PRA.

*Denial of Request for Reinstatement (§ 402.306)*

Section 402.306(a) explains that if a request for reinstatement is denied, the initiating agency must notify the excluded person in writing. This section also states that within 30 days of the date of the notice of denial, the excluded person may submit to the initiating agency—documentary evidence and a written argument challenging the reinstatement denial; or a written request to present written evidence or oral argument to an official of the initiating agency.

The burden associated with this requirement is the time and effort necessary for the excluded person to provide the aforementioned information. While this requirement imposes burden, we believe it is exempt from the PRA as defined in 5 CFR 1320.4; information collected during the conduct of a criminal investigation or civil action or during the conduct of an administrative action, investigation, or audit involving an agency against specific individuals or entities is not subject to the PRA.

*Waivers of Exclusions (§ 402.308)*

Section 402.308 discusses the process involved in obtaining a waiver of exclusions. Section 402.308(a) states that persons may request of CMS to present, on their behalf, a request to the Office of the Inspector General (OIG) for a waiver of the exclusion. The request must be in writing and will only be considered if it meets the criteria listed in this section. If the individual or entity meet the criteria, the written request for a waiver of exclusion must provide, at a minimum, the information listed under § 402.308(b).

The burden associated with this requirement is the time and effort necessary to prepare and submit to CMS the written document requesting a waiver of exclusion. While this requirement imposes burden, we believe it is exempt from the PRA as defined in 5 CFR 1320.4; information collected during the conduct of a criminal investigation or civil action or during the conduct of an administrative action, investigation, or audit involving an agency against specific individuals or entities is not subject to the PRA.

**V. Regulatory Impact Statement**

We have examined the impacts of this final rule as required by Executive Order 12866 (September 1993, Regulatory Planning and Review), the Regulatory Flexibility Act (RFA) (September 19, 1980, Pub. L. 96–354), section 1102(b) of the Social Security Act, the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4), and Executive Order 13132.

Executive Order 12866 directs agencies to assess all costs and benefits of available regulatory alternatives and, if regulation is necessary, to select regulatory approaches that maximize net benefits (including potential economic, environmental, public health and safety effects, distributive impacts, and equity). A regulatory impact analysis (RIA) must be prepared for major rules with economically significant effects ($100 million or in any 1 year). This rule does not reach the economic threshold and thus is not considered a major rule. Any impact that may occur would only affect those limited few persons that engage in prohibited behavior. We do not anticipate any savings or costs as a result of this final rule.

The RFA requires agencies to analyze options for regulatory relief of small businesses. For purposes of the RFA, small entities include small businesses, nonprofit organizations, and small government jurisdictions. Most hospitals and most other providers and suppliers are small entities, either by nonprofit status or by having revenues of $6 million to $29 million in any 1 year. Individuals and States are not included in the definition of a small entity. We are not preparing an analysis for the RFA because we have determined that this rule will not have a significant economic impact on a substantial number of small entities. We believe that any impact as a result of the final rule will be minimal, since the only persons affected would be those limited few who engage in prohibited conduct. Since the vast majority of program participants comply with statutory and regulatory requirements, any aggregate economic impact would not be significant.

In addition, section 1102(b) of the Act requires us to prepare a regulatory impact analysis if a rule may have a significant impact on the operations of a substantial number of small rural hospitals. This analysis must conform to the provisions of section 604 of the RFA. For purposes of section 1102(b) of the Act, we define a small rural hospital as a hospital that is located outside of a Metropolitan Statistical Area and has fewer than 100 beds. We are not preparing an analysis for section 1102(b) of the Act because we have determined that this rule will not have a significant impact on the operations of a substantial number of small rural hospitals.

Section 202 of the Unfunded Mandates Reform Act of 1995 also requires that agencies assess anticipated costs and benefits before issuing any rule whose mandates require spending in any 1 year of $100 million in 1995 dollars, updated annually for inflation. That threshold is currently approximately $120 million. This rule will have no consequential effect on State, local, or tribal governments, or by the private sector since the majority of program participants comply with statutory and regulatory requirements.

Executive Order 13132 establishes certain requirements that an agency must meet when it publishes a final rule that imposes substantial direct requirement costs on State and local governments, preempts State law, or otherwise has Federalism implications. Since this regulation does not impose any costs on State or local governments, the requirements of E.O. 13132 are not applicable.

In accordance with the provisions of Executive Order 12866, the Office of Management and Budget reviewed this regulation.

**List of Subjects in 42 CFR Part 402**

Administrative practice and procedure, Medicaid, Medicare, Penalties.

■ For the reasons set forth in the preamble, the Centers for Medicare & Medicaid Services amends 42 CFR chapter IV part 402 as set forth below:

## PART 402—CIVIL MONEY PENALTIES, ASSESSMENTS, AND EXCLUSIONS

■ 1. The authority citation for part 402 continues to read as follows:

**Authority:** Sections 1102 and 1871 of the Social Security Act (42 U.S.C. 1302 and 1395hh).

## Subpart A—General Provisions

### § 402.1 [Amended]

■ 2. In § 402.3, add the definition of ''initiating agency'' in alphabetical order to read:

### § 402.3 Definitions.

* * * * *

*Initiating agency* means whichever agency (CMS or the OIG) initiates the interaction with the person.

* * * * *

## Subpart B—Civil Money Penalties and Assessments

■ 3. In § 402.105, redesignate paragraph (d)(1)(xix) as paragraph (d)(1)(ix).

■ 4. In part 402, add a new subpart C to read as follows:

### Subpart C—Exclusions

Sec.



## Subpart C—Exclusions

### § 402.200 Basis and purpose.

(a) *Basis.* This subpart is based on the sections of the Act that are specified in § 402.1(e).

(b) *Purpose.* This subpart—

(1) Provides for the imposition of an exclusion from the Medicare and Medicaid programs (and, where applicable, other Federal health care programs) against persons that violate the provisions of the Act provided in § 402.1(e) (and further described in § 402.1(c)); and

(2) Sets forth the appeal rights of persons subject to exclusion and the procedures for reinstatement following exclusion.

### § 402.205 Length of exclusion.

The length of exclusion from participation in Medicare, Medicaid, and, where applicable, other Federal health care programs, is contingent upon the specific violation of the Medicare statute. A full description of the specific violations identified in the sections of the Act are cross-referenced in the regulatory sections listed in the table in paragraph (a) of this section.

(a) In no event will the period of exclusion exceed 5 years for violation of the following sections of the Act:

| Social Security Act paragraph | Code of Federal Regulations section |
|---|---|
| 1833(h)(5)(D) in repeated cases. | § 402.1(c)(1) |
| 1833(q)(2)(B) in repeated cases. | § 402.1(c)(3) |
| 1834(a)(11)(A) | § 402.1(c)(4) |
| 1834(a)(18)(B) | § 402.1(c)(5) |
| 1834(b)(5)(C) | § 402.1(c)(6) |
| 1834(c)(4)(C) | § 402.1(c)(7) |
| 1834(h)(3) | § 402.1(c)(8) |
| 1834(j)(4) | § 402.1(c)(10) |
| 1834(k)(6) | § 402.1(c)(31) |
| 1834(l)(6) | § 402.1(c)(32) |
| 1842(b)(18)(B) | § 402.1(c)(11) |
| 1842(k) | § 402.1(c)(12) |
| 1842(l)(3) | § 402.1(c)(13) |
| 1842(m)(3) | § 402.1(c)(14) |
| 1842(n)(3) | § 402.1(c)(15) |
| 1842(p)(3)(B) in repeated cases. | § 402.1(c)(16) |
| 1848(g)(1)(B) in repeated cases. | § 402.1(c)(17) |
| 1848(g)(3)(B) | § 402.1(c)(18) |
| 1848(g)(4)(B)(ii) in repeated cases. | § 402.1(c)(19) |
| 1879(h) | § 402.1(c)(23) |

(b) For violation of the following sections, there is no maximum time limit for the period of exclusion.

| Social Security Act paragraph | Code of Federal Regulations section |
|---|---|
| 1834(a)(17)(c) for a pattern of contacts. | § 402.1(e)(2)(i) |
| 1834(h)(3) for a pattern of contacts. | § 402.1(e)(2)(ii) |
| 1877(g)(5) | § 402.1(c)(22) |
| 1882(a)(2) | § 402.1(c)(24) |
| 1882(p)(8) | § 402.1(c)(25) |
| 1882(p)(9)(C) | § 402.1(c)(26) |
| 1882(q)(5)(C) | § 402.1(c)(27) |
| 1882(r)(6)(A) | § 402.1(c)(28) |
| 1882(s)(4) | § 402.1(c)(29) |
| 1882(t)(2) | § 402.1(c)(30) |

(c) For a person excluded under any of the grounds specified in paragraph (a) of this section, notwithstanding any other requirements in this section, reinstatement occurs—

(1) At the expiration of the period of exclusion, if the exclusion was imposed for a period of 5 years; or

(2) At the expiration of 5 years from the effective date of the exclusion, if the exclusion was imposed for a period of less than 5 years and the initiating agency did not receive the appropriate written request for reinstatement as specified in § 402.300.

**§ 402.208 Factors considered in determining whether to exclude, and the length of exclusion.**

(a) *General factors.* In determining whether to exclude a person and the length of exclusion, the initiating agency considers the following:

(1) The nature of the claims and the circumstances under which they were presented.

(2) The degree of culpability, the history of prior offenses, and the financial condition of the person presenting the claims.

(3) The total number of acts in which the violation occurred.

(4) The dollar amount at issue (Medicare Trust Fund dollars or beneficiary out-of-pocket expenses).

(5) The prior history of the person insofar as its willingness or refusal to comply with requests to correct said violations.

(6) Any other facts bearing on the nature and seriousness of the person's misconduct.

(7) Any other matters that justice may require.

(b) *Criteria to be considered.* As a guideline for taking into account the general factors listed in paragraph (a) of this section, the initiating agency may consider any one or more of the circumstances listed in paragraphs (b)(1) and (b)(2) of this section, as applicable. The respondent, in his or her written response to the notice of intent to exclude (that is, the proposed exclusion), may provide information concerning potential mitigating circumstances.

(1) *Aggravating circumstances.* An aggravating circumstance may be any of the following:

(i) The services or incidents were of several types and occurred over an extended period of time.

(ii) There were numerous services or incidents, or the nature and circumstances indicate a pattern of claims or requests for payment or a pattern of incidents, or whether a specific segment of the population was targeted.

(iii) Whether the person was held liable for criminal, civil, or administrative sanctions in connection with a program covered by this part or any other public or private program of payment for health care items or services at any time before the incident or whether the person presented any claim or made any request for payment that included an item or service subject to a determination under § 402.1.

(iv) There is proof that the person engaged in wrongful conduct, other than the specific conduct upon which liability is based, relating to government programs and in connection with the delivery of a health care item or service. The statute of limitations governing civil money penalty proceedings at section 1128A(c)(1) of the Act does not apply to proof of other wrongful conducts as an aggravating circumstance.

(v) The wrongful conduct had an adverse impact on the financial integrity of the Medicare program or its beneficiaries.

(vi) The person was the subject of an adverse action by any other Federal, State, or local government agency or board, and the adverse action is based on the same set of circumstances that serves as a basis for the imposition of the exclusion.

(vii) The noncompliance resulted in a financial loss to the Medicare program of at least $5,000.

(viii) The number of instances for which full, accurate, and complete disclosure was not made as required, or provided as requested, and the significance of the undisclosed information.

(2) *Mitigating circumstances.* A mitigating circumstance may be any of the following:

(i) All incidents of noncompliance were few in nature and of the same type, occurred within a short period of time, and the total amount claimed or requested for the items or services provided was less than $1,500.

(ii) The claim(s) or request(s) for payment for the item(s) or service(s) provided by the person were the result of an unintentional and unrecognized error in the person's process for presenting claims or requesting payment, and the person took corrective steps promptly after the error was discovered.

(iii) Previous cooperation with a law enforcement or regulatory entity resulted in convictions, exclusions, investigations, reports for weaknesses, or civil money penalties against other persons.

(iv) Alternative sources of the type of health care items or services furnished by the person are not available to the Medicare population in the person's immediate area.

(v) The person took corrective action promptly upon learning of the noncompliance from the person's employee or contractor, or by the Medicare contractor.

(vi) The person had a documented mental, emotional, or physical condition before or during the commission of the noncompliant act(s) and that condition reduces the person's culpability for the acts in question.

(vii) The completeness and timeliness of refunding to the Medicare Trust Fund or Medicare beneficiaries any inappropriate payments.

(viii) The degree of culpability of the person in failing to provide timely and complete refunds.

(3) *Other matters as justice may require.* Other circumstances of an aggravating or mitigating nature are taken into account if, in the interest of justice, those circumstances require either a reduction or increase in the sanction to ensure achievement for the purposes of this subpart.

(4) *Initiating agency authority.* Nothing in this section limits the authority of the initiating agency to settle any issue or case as provided by § 402.17, or to compromise any penalty and assessment as provided by § 402.115.

**§ 402.209 Scope and effect of exclusion.**

(a) *Scope of exclusion.* Under this title, persons may be excluded from the Medicare, Medicaid, and, where applicable, any other Federal health care programs.

(b) *Effect of exclusion on a person(s).* (1) Unless and until an excluded person is reinstated into the Medicare program, no payment is made by Medicare, Medicaid, and, where applicable, any other Federal health care programs for any item or service furnished by the excluded person or at the direction or request of the excluded person when the person furnishing the item or service knew or had reason to know of the exclusion, on or after the effective date of the exclusion as specified in the notice of exclusion.

(2) An excluded person may not take assignment of a Medicare beneficiary's claim on or after the effective date of the exclusion.

(3) An excluded person that submits, or causes to be submitted, claims for items or services furnished during the exclusion period is subject to civil money penalty liability under section 1128A(a)(1)(D) of the Act, and criminal liability under section 1128B(a)(3) of the Act. In addition, submission of claims, or the causing of claims to be submitted for items or services furnished, ordered, or prescribed, by an excluded person may serve as the basis for denying reinstatement to the Medicare program.

(c) *Exceptions.* (1) If a Medicare beneficiary or other person (including a supplier) submits an otherwise payable claim for items or services furnished by an excluded person, or under the medical direction or on the request of an excluded person after the effective date of the exclusion, CMS pays the first claim submitted by the beneficiary or other person and immediately notifies the claimant of the exclusion. CMS does not pay a beneficiary or other person (including a supplier) for items or services furnished by, or under, the medical direction of an excluded person more than 15 days after the date on the notice to the beneficiary or other person (including a supplier), or after the effective date of the exclusion, whichever is later.

(2) Notwithstanding the other provisions of this section, payment may be made for certain emergency items or services furnished by an excluded person, or under the medical direction or on the request of an excluded person during the period of exclusion. To be payable, a claim for the emergency items or services must be accompanied by a sworn statement of the person furnishing the items or services, specifying the nature of the emergency and the reason that the items or services were not furnished by a person eligible to furnish or order the items or services. No claim for emergency items or services is payable if those items or services were provided by an excluded person that, through employment, contractual, or under any other arrangement, routinely provides emergency health care items or services.

**§ 402.210 Notices.**

(a) *Notice of proposed determination to exclude.* When the initiating agency proposes to exclude a person from participation in a Federal health care program in accordance with this part, notice of the proposed determination to exclude must be given in writing, and delivered or sent by certified mail, return receipt requested. The written notice must include, at a minimum—

(1) Reference to the statutory basis for the exclusion.

(2) A description of the claims, requests for payment, or incidents for which the exclusion is proposed.

(3) The reason why those claims, requests for payments, or incidents subject the person to an exclusion.

(4) The length of the proposed exclusion.

(5) A description of the circumstances that were considered when determining the period of exclusion.

(6) Instructions for responding to the notice, including a specific statement of the person's right to submit documentary evidence and a written response concerning whether the exclusion is warranted, and any related issues such as potential mitigating circumstances. The notice must specify that—

(i) The person has the right to request an opportunity to meet with an official of the initiating agency to make an oral presentation; and

(ii) The request to make an oral presentation must be submitted within 30 days of the receipt of the notice of intent to exclude.

(7) If a person fails, within the time permitted under § 402.212, to exercise the right to respond to the notice of proposed determination to exclude, the initiating agency may initiate actions for the imposition of the exclusion.

(b) *Notice of exclusion.* Once the initiating agency determines that the exclusion is warranted, a written notice of exclusion is sent to the person in the same manner as described in paragraph (a) of this section. The exclusion is effective 20 days from the date of the notice. The written notice must include, at a minimum, the following:

(1) The basis for the exclusion.

(2) The length of the exclusion and, when applicable, the factors considered in setting the length.

(3) The effect of exclusion.

(4) The earliest date on which the initiating agency considers a request for reinstatement.

(5) The requirements and procedures for reinstatement.

(6) The appeal rights available to the excluded person under part 1005 of this title.

(c) *Amendment to the notice of exclusion.* No later than 15 days before the final exhibit exchanges required under § 1005.8 of this title, the initiating agency may amend the notice of exclusion if information becomes available that justifies the imposition of a period of exclusion other than the one proposed in the original written notice.

**§ 402.212 Response to notice of proposed determination to exclude.**

(a) A person that receives a notice of intent to exclude (that is, the proposed determination) as described in § 402.210, may present to the initiating agency a written response stating whether the proposed exclusion is warranted, and may present additional supportive documentation. The person must submit this response within 60 days of the receipt of notice. The initiating agency reviews the materials presented and initiates a response to the person regarding the argument presented, and any changes to the determination, if appropriate.

(b) The person is also afforded an opportunity to make an oral presentation to the initiating agency concerning whether the proposed exclusion is warranted and any related matters. The person must submit this request within 30 days of the receipt of notice. Within 15 days of receipt of the person's request, the initiating agency initiates communication with the person to establish a mutually agreed upon time and place for the oral presentation and discussion.

**§ 402.214 Appeal of exclusion.**

(a) The procedures in part 1005 of this title apply to all appeals of exclusions. References to the Inspector General in that part apply to the initiating agency.

(b) A person excluded under this subpart may file a request for a hearing before an administrative law judge (ALJ) only on the issues of whether—

(1) The basis for the imposition of the exclusion exists; and

(2) The duration of the exclusion is unreasonable.

(c) When the initiating agency imposes an exclusion for a period of 1 year or less, paragraph (b)(2) of this section does not apply.

(d) The excluded person must file a request for a hearing within 60 days from the receipt of notice of exclusion. The effective date of an exclusion is not delayed beyond the date stated in the notice of exclusion simply because a request for a hearing is timely filed (see paragraph (g) of this section).

(e) A timely filed written request for a hearing must include—

(1) A statement as to the specific issues or findings of fact and conclusions of law in the notice of exclusion with which the person disagrees.

(2) Basis for the disagreement.

(3) The general basis for the defenses that the person intends to assert.

(4) Reasons why the proposed length of exclusion should be modified.

(5) Reasons, if applicable, why the health or safety of Medicare beneficiaries receiving items or services does not warrant the exclusion going into or remaining in effect before the completion of an ALJ proceeding in accordance with part 1005 of this title.

(f) If the excluded person does not file a written request for a hearing as provided in paragraph (d) of this section, the initiating agency notifies the excluded person, by certified mail, return receipt requested, that the exclusion goes into effect or continues in accordance with the notice of exclusion. The excluded person has no right to appeal the exclusion other than as described in this section.

(g) If the excluded person files a written request for a hearing, and asserts in the request that the health or safety of Medicare beneficiaries does not warrant the exclusion going into or remaining in effect before completion of an ALJ hearing, then the initiating agency may make a determination as to whether the exclusion goes into effect or continues pending the outcome of the ALJ hearing.

**§ 402.300 Request for reinstatement.**

(a) An excluded person may submit a written request for reinstatement to the initiating agency no sooner than 120 days prior to the terminal date of exclusion as specified in the notice of exclusion. The written request for reinstatement must include documentation demonstrating that the person has met the standards set forth in § 402.302. Obtaining or reactivating a Medicare provider number (or equivalent) does not constitute reinstatement.

(b) Upon receipt of a written request for reinstatement, the initiating agency may require the person to furnish additional, specific information, and authorization to obtain information from private health insurers, peer review organizations, and others as necessary to determine whether reinstatement is granted.

(c) Failure to submit a written request for reinstatement or to furnish the required information or authorization results in the continuation of the exclusion, unless the exclusion has been in effect for 5 years. In this case, reinstatement is automatic.

(d) If a period of exclusion is reduced on appeal (regardless of whether further appeal is pending), the excluded person may request and apply for reinstatement within 120 days of the expiration of the reduced exclusion period. A written request for the reinstatement includes the same standards as noted in paragraph (b) of this section.

**§ 402.302 Basis for reinstatement.**

(a) The initiating agency authorizes reinstatement if it determines that—

(1) The period of exclusion has expired;

(2) There are reasonable assurances that the types of actions that formed the basis for the original exclusion did not recur and will not recur; and

(3) There is no additional basis under title XVIII of the Act that justifies the continuation of the exclusion.

(b) The initiating agency does not authorize reinstatement if it determines that submitting claims or causing claims to be submitted or payments to be made by the Medicare program for items or services furnished, ordered, or prescribed, may serve as a basis for denying reinstatement. This section applies regardless of whether the excluded person has obtained a Medicare provider number (or equivalent), either as an individual or as a member of a group, before being reinstated.

(c) In making a determination regarding reinstatement, the initiating agency considers the following:

(1) Conduct of the excluded person occurring before the date of the notice of the exclusion, if that conduct was not known to the initiating agency at the time of the exclusion;

(2) Conduct of the excluded person after the date of the exclusion;

(3) Whether all fines and all debts due and owing (including overpayments) to any Federal, State, or local government that relate to Medicare, Medicaid, or, where applicable, any Federal, State, or local health care program are paid in full, or satisfactory arrangements are made to fulfill these obligations;

(4) Whether the excluded person complies with, or has made satisfactory arrangements to fulfill, all of the applicable conditions of participation or conditions of coverage under the Medicare statutes and regulations; and

(5) Whether the excluded person has, during the period of exclusion, submitted claims, or caused claims to be submitted or payment to be made by Medicare, Medicaid, and, where applicable, any other Federal health care program, for items or services furnished, ordered, or prescribed, and the conditions under which these actions occurred.

(d) Reinstatement is not effective until the initiating agency grants the request and provides notices under § 402.304. Reinstatement is effective as provided in the notice.

(e) A determination for a denial of reinstatement is not appealable or reviewable except as provided in § 402.306.

(f) An ALJ may not require reinstatement of an excluded person in accordance with this chapter.

**§ 402.304 Approval of request for reinstatement.**

(a) If the initiating agency grants a request for reinstatement, the initiating agency—

(1) Gives written notice to the excluded person specifying the date of reinstatement; and

(2) Notifies appropriate Federal and State agencies, and, to the extent possible, all others that were originally notified of the exclusion, that the person is reinstated into the Medicare program.

(b) A determination by the initiating agency to reinstate an excluded person has no effect if Medicare, Medicaid, or, where applicable, any other Federal health care program has imposed a longer period of exclusion under its own authorities.

**§ 402.306 Denial of request for reinstatement.**

(a) If a request for reinstatement is denied, the initiating agency provides written notice to the excluded person. Within 30 days of the date of this notice, the excluded person may submit to the initiating agency:

(1) Documentary evidence and a written argument challenging the reinstatement denial; or

(2) A written request to present written evidence or oral argument to an official of the initiating agency.

(b) If a written request as described in paragraph (a)(2) of this section is received timely by the initiating agency, the initiating agency, within 15 days of receipt of the excluded person's request, initiates communication with the excluded person to establish a time and place for the requested meeting.

(c) After evaluating any additional evidence submitted by the excluded person (or at the end of the 30-day period described in paragraph (a) of this section, if no documentary evidence or written request is submitted), the initiating agency sends written notice to the excluded person either confirming the denial, or approving the reinstatement in the manner set forth in § 402.304. If the initiating agency elects to uphold its denial decision, the written notice also indicates that a subsequent request for reinstatement will not be considered until at least 1 year after the date of the written denial notice.

(d) The decision to deny reinstatement is not subject to administrative review.

**§ 402.308 Waivers of exclusions.**

(a) *Basis.* Section 1128(c)(3)(B) of the Act specifies that in the case of an exclusion from participation in the Medicare program based upon section 1128(a)(1), (a)(3), or (a)(4) of the Act, the individual may request that CMS present, on his or her behalf, a request to the OIG for a waiver of the exclusion.

(b) *Definitions.* For purposes of this section:

*Excluded person* has the same meaning as a ''person'' as defined in § 402.3 who meets for the purposes of this subpart, the definition of the term ''exclusion'' in § 402.3.

*Hardship* for purposes of this section means something that negatively affects Medicare beneficiaries and results from the imposition of an exclusion because the excluded person is the sole community physician or sole source of essential specialized services in the Medicare community.

*Sole community physician* has the same meaning as that term is defined § 1001.2 of this title.

*Sole source of essential specialized services in the community* has the same meaning as that term defined by the § 1001.2 of this title.

(c) *General rule.* If CMS determines that a hardship as defined in paragraph (b)(2) of this section results from exclusion of an affected person from the Medicare program, CMS may consider and may make a request to the Inspector General for waiver of the Medicare exclusion.

(d) *Submission and content of a waiver of exclusion request.* An excluded person must submit a request for waiver of exclusion in writing to CMS that includes the following:

(1) A copy of the exclusion notice from the OIG.

(2) A statement requesting that CMS present a waiver of exclusion request to the OIG on his or her behalf.

(3) A statement that he or she is the sole community physician or sole source of essential specialized services in the community.

(4) Documentation to support the statement in paragraph (d)(3) of this section.

(e) *Processing of waiver of exclusion requests.* CMS processes a request for a waiver of exclusion as follows:

(1) Notifies the submitter that the waiver of exclusion request has been received.

(2) Reviews and validates all submitted documents.

(3) During its analysis, CMS may require additional, specific information, and authorization to obtain information from private health insurers, peer review organizations (including, but not limited to, Quality Improvement Organizations), and others as necessary to determine validity.

(4) Makes a determination regarding whether or not to submit the waiver of exclusion request to the OIG based on review and validation of the submitted documents.

(5) If CMS elects to submit the waiver of exclusion request to the OIG, CMS copies the excluded person on the request.

(6) If CMS denies the request, then CMS notifies the excluded person of the decision and specifies the reason(s) for the decision.

(f) *Administrative or judicial review.* A determination rendered under paragraph (e)(4) of this section is not subject to administrative or judicial review.

(Catalog of Federal Domestic Assistance Program No. 93.773, Medicare—Hospital Insurance; and Program No. 93.774, Medicare—Supplementary Medical Insurance Program)

Dated: December 14, 2006.

**Leslie V. Norwalk,**

*Acting Administrator, Centers for Medicare & Medicaid Services.*

Approved: March 26 2007.

**Michael O. Leavitt,**

*Secretary.*

**Editorial Note:** This document was received at the Office of the Federal Register on July 9, 2007.

[FR Doc. E7–13535 Filed 7–19–07; 8:45 am]

BILLING CODE 4120–01–P

## FEDERAL COMMUNICATIONS COMMISSION

### 47 CFR Parts 0 and 90

**[WT Docket No. 02–55, ET Docket No. 00–258; ET Docket No. 95–18; RM–9498; RM–10024—FCC 07–102]**

## Improving Public Safety Communications in the 800 MHz Band, et al.

**AGENCY:** Federal Communications Commission.

**ACTION:** Final rule, clarification.

**SUMMARY:** In the Second Memorandum Opinion and Order, the Commission affirms and clarifies various rules governing the 800 MHz band reconfiguration process designed to improve public safety communications. The Second Memorandum Opinion and Order addresses various petitions for reconsideration and clarification asking the Commission to revisit certain decisions in the 800 MHz band reconfiguration proceeding.

**DATES:** Effective August 20, 2007.

**FOR FURTHER INFORMATION CONTACT:** John Evanoff, Public Safety and Homeland Security Bureau, (202) 418–0848, or via the Internet at *John.Evanoff@fcc.gov.*

**SUPPLEMENTARY INFORMATION:** This document summarizes the Second Memorandum Opinion and Order in WT Docket No. 02–55, adopted on May 24, 2007, and released on May 30, 2007. The full text of this document is available for public inspection on the Commission's Internet site at *http://www.fcc.gov.* It is also available for inspection and copying during regular business hours in the FCC Reference Center (Room CY–A257), 445 12th Street, SW., Washington, DC 20554. The full text of this document also may be purchased from the Commission's duplication contractor, Best Copy and Printing Inc., Portals II, 445 12th St., SW., Room CY–B402, Washington, DC 20554; telephone (202) 488–5300; fax (202) 488–5563; e-mail *FCC@BCPIWEB.COM.*

**Background**

1. In the 800 MHz Report and Order, 69 FR 67823, November 22, 2004, the Commission adopted technical and procedural measures to address the ongoing and growing problem of interference to public safety communications in the 800 MHz band. Specifically, the Commission addressed the ongoing interference problem over the short-term by adopting technical standards defining unacceptable interference in the 800 MHz band and detailing responsibility for interference abatement. The Commission further determined that solving the interference problem for the long-term necessitated reconfiguring the 800 MHz band to separate generally incompatible technologies whose current proximity to each other is the identified root cause of unacceptable interference. Accordingly, the Commission adopted a new band plan for the 800 MHz band and established a transition mechanism for licensees in the band to relocate to their new spectrum assignments. The Commission subsequently issued a Supplemental Order and Order on Reconsideration, 70 FR 6758, February 8, 2005, making certain clarifications of, and changes to, the provisions of the 800 MHz Report and Order and its accompanying interference mitigation and band reconfiguration rules. In October 2005, the Commission released a Memorandum Opinion and Order (800 MHz MO&O), 70 FR 76704, December 28, 2005, making certain further changes and clarifications to the 800 MHz interference mitigation and band reconfiguration rules. In this Order, we address various petitions for reconsideration and clarification of the Commission's 800 MHz MO&O, previously unaddressed portions of a petition for reconsideration of the 800 MHz Report and Order and a petition for partial waiver of the rebanding rules, as well as several petitions dealing with clearing of the 1.9 GHz Broadcast Auxiliary Services (BAS) band, including a joint petition for declaratory ruling and several petitions for clarification or reconsideration.

**Discussion**

2. The Second Memorandum Opinion and Order affirms the eligibility criteria for relocating licensees to the enhanced specialized mobile radio (ESMR) band. In addition to affirming the eligibility criteria for relocation to the ESMR band, the order released today also clarifies the costs that Sprint Nextel Corp. (Sprint) must pay to relocate non-ESMR licensees relocating to the ESMR band.

3. The Commission also denied petitions seeking to require Sprint Nextel to pay licensees' post-mediation litigation costs. The order also clarifies procedures that are to be used if there is a shortfall of spectrum in the ESMR band and outlines steps for a revised band plan and timetable for the Puerto Rico market. It also addresses rebanding for Guam, the Northern Mariana Islands, American Samoa, and the Gulf of Mexico and clarifies the 800 MHz application freeze's impact on modification applications. The order also defines limits on Sprint Nextel operations that are near public safety channels before the transition is completed. The order also denied a petition filed by Mobile Relay Associates seeking a partial waiver of the rebanding rules to allow it to relocate to the ESMR band. The order also denies a petition filed by Charles Guskey as repetitive and untimely.

4. The order also partially grants petitions asking the FCC to require Sprint Nextel to relocate broadcast auxiliary service (BAS) facilities associated to translator TV stations or operated by full-power TV stations on a short-term basis. The Commission said it will permit, but not require, the carrier to pay and claim credit for such costs. The order also delegates to the Public Safety and Homeland Security Bureau the authority to adopt rules for the Canadian and Mexican border regions once spectrum-sharing agreements between the U.S. and those countries are finalized.

**Final Regulatory Flexibility Certification**

5. The Regulatory Flexibility Act of 1980, as amended (RFA), requires that a regulatory flexibility analysis be prepared for notice-and-comment rule making proceedings, unless the agency certifies that ''the rule will not, if promulgated, have a significant economic impact on a substantial number of small entities.'' The RFA generally defines the term ''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). In sum, we certify that the rule changes and actions in this Second Memorandum Opinion and Order will not have a significant economic impact on a substantial number of small entities.

6. *ESMR Band Eligibility.* In this proceeding the Commission divided the 800 MHz band into a cellular portion (ESMR band) and non-cellular portion to create spectral separation between incompatible technologies. Section 90.614 provides that the cellular portion would be reserved for licensees that operate cellular high density systems. Several parties sought reconsideration of the eligibility and operating requirements applicable to the cellular band arguing that these requirements are overly restrictive. In the 800 MHz Memorandum Opinion and Order, we clarified eligibility of licensees to relocate to the ESMR band to include low-density cellular operations and deferred consideration of a petition for reconsideration filed by Richard M. Duncan seeking to permit site-based Specialized Mobile Radio (SMR) licensees to relocate to the ESMR band. Sprint Nextel Corporation sought reconsideration of the provisions of the 800 MHz MO&O that clarified and expanded the rights of certain licensees other than Sprint and SouthernLINC to relocate to the ESMR band. After careful analysis, we find no reason to upset the Commission's balancing of interests that led to the revised eligibility criteria for the ESMR band contained in the 800 MHz MO&O. Those criteria are designed to eliminate potential interference between incompatible technologies and to provide ESMR licensees flexibility in managing their systems. Here, we affirm the eligibility criteria established in the 800 MHz MO&O for relocation to the ESMR band and are taking no action with respect to any entity. Therefore, we certify that our decision to deny the Sprint and Duncan petitions will not have a significant economic impact on a substantial number of small entities.

7. *ESMR Band Plan.* In some Southeastern markets where both Southern LINC and Sprint offer ESMR service, insufficient spectrum exists in the 816–824/861–869 MHz band segment to accommodate existing ESMR systems. To accommodate Sprint and SouthernLINC, the Commission created an expanded ESMR band in the Southeast. Sprint sought clarification that the 800 MHz Report and Order ''adopted two remedies in the event there is insufficient spectrum in the ESMR segment to accommodate all eligible licensees in a market: (1) Expanding the ESMR segment and, in

the event a channel shortfall remained (2) distributing the available channels on a pro rata basis among licensees.'' Although we agree with Sprint that the Commission has the discretion to apportion ESMR spectrum, we find no support for Sprint's contention that licensees themselves have similar discretion. We also clarify that under limited circumstances, the Commission may apportion the ESMR band pro rata to licensees eligible to operate there. Because our decision merely clarifies pre-existing rules applicable to the ESMR Band, we have adopted no new rule and have taken no other action that affects any entity. Therefore, we certify that our decision will not have a significant economic impact on a substantial number of small entities.

8. *Puerto Rico.* The Puerto Rico market presents a unique situation that is distinct from other markets. Sprint holds considerably less spectrum in Puerto Rico than it does elsewhere, and there are several other licensees who have acquired significant EA license holdings in Puerto Rico at auction and seek to operate as ESMRs. In addition, Puerto Rico has numerous site-based incumbents that will need to be relocated to the non-ESMR block. Thus, an alternative band plan is appropriate here. Accordingly we provide the 800 MHz Transition Administrator (TA) with specific criteria and direct the TA to propose an alternative band plan within 60 days of the release of this order, including, if necessary, a pro rata distribution of ESMR spectrum. At this time, we have no basis for anticipating that any future decision by the TA in either proposing an alternative band plan or proposing a pro rata distribution would adversely affect any small entities. Accordingly, at this time, we certify that our decision will not have a significant economic impact on a substantial number of small entities.

9. Furthermore, to the extent that any action taken in the future might impose an adverse economic impact in Puerto Rico, that impact will be borne by Sprint because Sprint must pay the costs of 800 MHz band reconfiguration. Under Small Business Administration criteria, Sprint is a large entity. Further, there is no evidence in the record that non-Sprint licensees in the Puerto Rico market, including small wireless cellular, public safety, governmental entities or other wireless entities, would suffer adverse economic consequences.

10. *Guam, the Northern Mariana Islands, American Samoa, and the Gulf of Mexico.* Sprint asks that we reconsider the Commission's decision in the 800 MHz MO&O to require band reconfiguration in areas that have no associated NPSPAC region. These areas include American Samoa, Guam, the Northern Mariana Islands, and the Gulf of Mexico. Because there are no public safety entities in the Gulf of Mexico and Sprint does not hold spectrum rights in the Gulf of Mexico, we see no risk in the Gulf of the type of interference to public safety systems that would require rebanding. However, we deny Sprint's request as it relates to Guam, the Northern Mariana Islands, and American Samoa. We believe that funding band reconfiguration in these markets does not pose an inequitable burden on Sprint. We take this position because Sprint alone will bear the cost of band reconfiguration in Guam, the Northern Mariana Islands, and American Samoa. Therefore, we certify that this action will not have a significant economic impact on a substantial number of small entities.

11. *Application Freeze.* In the 800 MHz Report and Order, the Commission imposed a freeze on the acceptance of 800 MHz applications in order to maintain a stable spectral landscape during the band relocation process. The Commission stated, however, that de minimis modifications to a currently authorized system are not subject to the application freeze so long as the modifications are necessary to effectuate band reconfiguration. Sprint requests that we broaden this exception to the freeze to ''permit certain license modifications * * * provided they do not materially diminish public safety's spectral or operational expectancies.'' While Sprint fails to define ''spectral or operational expectancies'' we agree that some flexibility may be appropriate. In this connection, we clarify that licensees may seek a waiver of the application freeze. Because grant of such a waiver would provide benefits to public safety service providers and to the public through improved public safety communications, we believe that only benefits will result. Therefore, we certify that this action will not have a significant economic impact on a substantial number of small entities.

12. *Post-litigation costs.* Under the 800 MHz Report and Order, Sprint is required to pay the costs of mediation to resolve disputes associated with a frequency reconfiguration agreement. The Wireless Telecommunications Bureau issued a public notice that stated: ''Licensees that enter mediation with Sprint Nextel are entitled to reimbursement of 'reasonable, prudent and necessary costs and expenses' associated with reaching a mediated frequency reconfiguration agreement. However, licensees who fail to reach a mediated agreement must bear their own costs associated [with] all further administrative or judicial appeals of band reconfiguration issues, including de novo review * * * and appeal of any such review before an A[dministrative] L[aw] J[udge].'' Some parties have filed petitions for reconsideration suggesting that the Commission require Sprint to pay opposing parties' litigation costs when they seek *de novo* review before the Commission of issues that have not been resolved by negotiation or TA-sponsored mediation. We deny those petitions. Under the Commission's orders in this proceeding, Sprint must pay all licensees' reasonable costs of negotiation and TA-sponsored mediation, regardless of outcome. This ensures that licensees can take full advantage of these mechanisms at no cost to themselves, while at the same time encouraging resolution of issues by negotiated agreement and mediation rather than litigation. However, requiring Sprint to pay its opponents' litigation costs before the Commission and beyond would increase the likelihood of litigation and add cost and delay to the rebanding process. Moreover, the Commission lacks statutory authority to award such costs in cases that come before it. While parties that pursue administrative or judicial appeals may incur some cost, such cost would be undertaken voluntarily. Further, there is no evidence in the record that a substantial number of parties will pursue such legal challenges. Therefore, we certify that this action will not have a significant economic impact on a substantial number of small entities.

13. *NPSPAC Band Operational Restrictions.* The Tri-State Radio Planning Committee, FCC Region 8 (Region 8) asks us to impose operational restrictions on Sprint in two distinct situations: (1) When a NPSPAC licensee has moved one or more of its channels to the new NPSPAC frequencies and Sprint has not yet completely vacated the former General Category channels and (2) when Sprint wishes to commence operations in the ESMR band, but has not fully cleared the ESMR band of NPSPAC incumbents. Region 8 is concerned that these situations, though temporary, could create the risk of harmful interference through the interleaving of incompatible technologies that was the genesis of this proceeding. To address this risk, Region 8 requests that: (a) We require Sprint to cease current operation on any channel 1–120 frequency within 25 kHz of relocated NPSPAC stations within 88 kilometers (km), and (b) Sprint not be allowed to begin operations on any

former NPSPAC channel within 88 kilometers of the site of any current NPSPAC station which has not been relocated to the new NPSPAC frequencies. Region 8 asks that we maintain these limitations in place until the entire NPSPAC band has been relocated and all relocated licensees have finalized the relocation process. Given that NPSPAC communications primarily involve the safety of life and property and because interference with these communications could have tragic results, we agree with Region 8's concerns. Because these operational restrictions apply only to Sprint, a large entity, we certify that this action will not have a significant economic impact on a substantial number of small entities.

14. *Charles Guskey Petition.* Charles Guskey, a principal of Preferred Communications, contends that the 800 MHz MO&O failed to adequately address his prior petition for reconsideration of the 800 MHz Supplemental Order. Guskey contends that: (1) The Commission undervalued the 1.9 GHz spectrum by at least a billion dollars, giving Nextel a windfall; (2) Preferred be allowed to relocate its General Category EA channels (encumbered or not) to clean spectrum in the ESMR band; and (3) Puerto Rico needs to be treated as a unique market, and Preferred awarded the 1.9 GHz spectrum in Puerto Rico in exchange for relocating public safety systems in that market. Because we dismiss the Petition as repetitive and untimely, we certify that this action will not have a significant economic impact on a substantial number of small entities.

15. *Broadcast Auxiliary Service Facilities.* We partially grant petitions to require Sprint to relocate BAS facilities associated with translator television stations or operated by full-power television stations on a short-term basis by permitting, but not requiring, Sprint to pay and claim credit for the costs incurred in relocating these BAS facilities. Some parties have filed petitions for reconsideration and clarification urging the Commission to require Sprint to relocate secondary BAS translator facilities. We instead permit, but not require, Sprint to relocate such facilities and to receive credit for such relocations at the ''true-up,'' consistent with Commission precedent regarding other secondary BAS stations. Because secondary BAS operations can be displaced at any time by primary operations, under well-established Commission policy the licensees of such facilities are not eligible for mandatory relocation reimbursement. Further, our narrow decision to permit Sprint to pay for relocation of secondary BAS facilities associated with translator and LPTV stations and short-term BAS facilities operating under section 74.24 is limited to the facts present here and may not be construed in other contexts as a revision of Commission rules and policies affecting stations operating pursuant to secondary authorizations. Also, allowing Sprint to pay for relocation of these secondary BAS facilities does not in any way alter Mobile Satellite Service licensees' obligations concerning the relocation of BAS incumbents with primary authorizations. Therefore, because our decision to permit such relocation affects only Sprint, a large entity, we certify that our decision to provide Sprint flexibility in managing BAS relocation will not have a significant economic impact on a substantial number of small entities.

16. *Southeast Band Plan.* In the 800 MHz MO&O, the Commission updated Sections 90.617(a), (b) and (d) to reflect the distribution of channels between the various categories in the SouthernLINC/Sprint markets located in the Southeastern part of the United States. Specifically, the Commission modified the band plan for the SouthernLINC/Sprint markets to reflect a reduced Expansion Band of one-half megahertz for those locations within a seventy mile radius of Atlanta, Georgia. As a result of this change, there are now two different band plans for the SouthernLINC/Sprint markets—one band plan for locations outside the seventy mile radius and one band plan for locations within a seventy mile radius of Atlanta, Georgia. The Commission inadvertently omitted this rule change. In this Second Memorandum Opinion and Order, the Commission on its own motion revises Section 90.617(g) and (h) to add a reference to vacated spectrum in the Atlanta market. This rule change is necessary to identify the particular spectrum that will be available for public safety and critical infrastructure industry use within a 70-mile radius of Atlanta and the spectrum that will be available outside that radius. We also remove all language from Section 90.617 which indicates that the agreement between SouthernLINC and Sprint still needs to be approved by the Wireless Telecommunications Bureau. Responsibility over the 800 MHz band reconfiguration proceeding has been delegated to the Public Safety and Homeland Security Bureau. Because these rule changes are procedural in nature and are intended to correct an inadvertent omission and reflect organizational changes, we certify that these changes will not have a significant economic impact on a substantial number of small entities.

17. *Band Plan.* On our own motion, we modify section 90.203(i)—pertaining to equipment certification—to reflect the location of the NPSPAC band after band reconfiguration. We also correct the base frequency for one of the frequencies listed in the table in section 90.613. The Commission inadvertently failed to update these sections in the 800 MHz Report and Order. Therefore, we correct these inadvertent omissions and certify that these changes will not have a significant economic impact on a substantial number of small entities.

18. *Border Area.* Finally, on our own motion, we address implementation of 800 MHz band plan rules for the Canadian and Mexican border regions. We delegate specific authority to the Public Safety and Homeland Security Bureau to propose and adopt new 800 MHz band plan rules for U.S. primary spectrum in the Canadian and Mexican border regions once the relevant agreements with Canada and Mexico are finalized. This is similar to authority that has been previously delegated to the Wireless Telecommunications Bureau. We amend therefore Section 0.392(e) of our rules to provide the Chief of the Public Safety and Homeland Security Bureau with the same delegated authority. Thus this rule change is purely procedural in nature and therefore we certify that these changes will not have a significant economic impact on a substantial number of small entities. Therefore, we certify that the requirements of the Second Memorandum Opinion and Order will not have a significant economic impact on a substantial number of small entities.

**Paperwork Reduction Act Analysis**

19. This document does not contain new or modified information collection requirements 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).

**Report to Congress**

20. The Commission will send a copy of this Report and Order, Second Memorandum Opinion and Order in a report to be sent to Congress and the General Accounting Office pursuant to the Congressional Review Act. In addition, the Second Memorandum

Opinion and Order and this final certification will be sent to the Chief Counsel for Advocacy of the Small Business Administration.

**Report to Small Business Administration**

21. The Commission's Consumer Information Bureau, Reference Information Center, shall send a copy of this Second Memorandum Opinion and Order including the Regulatory Flexibility Certification and to the Chief Counsel for Advocacy of the Small Business Administration.

**Ordering Clauses**

22. Accordingly, *It is ordered* that, pursuant to Sections 4(i), 303(f), 332, 337 and 405 of the Communications Act of 1934, as amended, 47 U.S.C. 154(i), 303(f), 332, 337 and 405, this Second Memorandum Opinion and Order is hereby adopted.

23. *It is further ordered* that, pursuant to Sections 1, 4(i), 303(f) and (r), 332, and 405 of the Communications Act of 1934, as amended, 47 U.S.C. 1, 154(i), 303(f) and (r), 332, and 405, the Request for Clarification of Communications & Industrial Electronics, Inc., North Sight Communications, Inc. and Ragan Communications, Inc. on January 27, 2006 is granted to the extent described herein and denied in all other respects.

24. *It is further ordered* that the Petition for Reconsideration of Report and Order, Fifth Report and Order, Fourth Memorandum Opinion and Order, and Order, filed by Richard W. Duncan d/b/a Anderson Communications, filed Dec. 22, 2004 is denied to the extent described herein.

25. *It is further ordered* that the Petition for Reconsideration filed by Charles D. Guskey on January 27, 2006, the Petition for Partial Reconsideration and Clarification filed by the Safety and Frequency Equity Competition Coalition on January 27, 2006; and the Petition for Reconsideration filed by Schwaninger & Associates are dismissed.

26. *It is further ordered* that the Petition for Clarification filed by Chair of the NPSPAC Region 8 Regional Planning Committee on March 3, 2006 is granted.

*It is further ordered* that the Petition for Reconsideration filed by Sprint Nextel Corporation, on January 27, 2006 is granted in part, denied in part, dismissed in part and deferred in part to the extent described herein.

27. *It is further ordered* that the Petitions for Clarification and/or Reconsideration filed by the Mohave County Board of Supervisors, the Association for Maximum Service Television, Fox Television Stations Inc., KTVK Inc., Multimedia Holdings Corporation, Meredith Corporation, and Scripps Howard Broadcasting Company on January 27, 2006 are granted in part and denied in part to the extent described herein.

28. *It is further ordered* that the Petition for Clarification filed by Fox Television Stations Inc. and Gray Television Licensee Inc. on March 20, 2007 Is granted in part and denied in part to the extent described herein.

29. *It is further ordered* pursuant to the authority of Section 4(i) of the Communications Act of 1934, as amended, 47 U.S.C. 154(i), and sections 1.925 of the Commission's Rules, 47 CFR 1.925 that the Request for Waiver submitted by Mobile Relay Associates in the above-captioned proceeding on January 24, 2006 is denied.

30. *It is further ordered* that the amendments of the Commission's Rules as set forth in Appendix B are adopted, effective August 24, 2007.

31. *It Is Further Ordered* that the Final Regulatory Flexibility Analysis, required by Section 604 of the Regulatory Flexibility Act, 5 U.S.C. 604, and as set forth herein is adopted.

**List of Subjects**

*47 CFR Part 0*

Commission organization.

*47 CFR Part 90*

Communications.

Federal Communications Commission.

**Marlene H. Dortch,**

*Secretary.*

**Rule Changes**

■ For the reasons discussed in the preamble, the Federal Communications Commission amends 47 CFR parts 0 and 90 as follows:

## PART 0—COMMISSION ORGANIZATION

■ 1. The authority citation for part 0 continues to read as follows:

**Authority:** Secs. 5, 48 Stat. 1068, as amended; 47 U.S.C. 155, 225, unless otherwise noted.

■ 2. Section 0.392(e) is revised to read as follows:

### § 0.392 Authority delegated.

* * * * *

(e) The Chief, Public Safety and Homeland Security Bureau shall not have authority to issue notices of proposed rulemaking, notices of inquiry, or reports or orders arising from either of the foregoing except such orders involving ministerial conforming amendments to rule parts, or orders conforming any of the applicable rules to formally adopted international conventions or agreements where novel questions of fact, law, or policy are not involved.

* * * * *

## PART 90—PRIVATE LAND MOBILE RADIO SERVICES

■ 3. The authority citation for part 90 continues to read as follows:

**Authority:** 4(i), 11, 303(g), 303(r), and 302(c)(7) of the Communications Act of 1934, as amended, 47 U.S.C. 154(i), 161, 303(g), 303(r), 332(c)(7).

■ 4. Section 90.203(i) is revised to read as follows:

### § 90.203 Certification required.

* * * * *

(i) Equipment certificated after February 16, 1988 and marketed for public safety operation in the 806–809/851–854 MHz bands must have the capability to be programmed for operation on the mutual aid channels as designated in § 90.617(a)(1) of the rules.

* * * * *

■ 5. The frequency table in § 90.613 is amended by revising the entry for channel 169 listed in Table of 806–824/851–869 MHz Channel Designations as follows.

### § 90.613 Frequencies available.

* * * * *

| Channel No. | Base frequency (MHz) |
|---|---|
| * * * * | * |
| 169 | .2250 |
| * * * * | * |

* * * * *

■ 6. Section 90.617 is amended by revising the undesignated introductory text and paragraphs (g) and (h) to read as follows:

### § 90.617 Frequencies in the 809.75–824/854.750–869 MHz, and 896–901/935–940 MHz bands available for trunked, conventional, or cellular system use in non-border areas.

The following channels will be available at locations farther then 110 km (68.4 miles) from the U.S./Mexico border and 140 km (87 miles) from the U.S./Canadian border (''non-border areas'').

* * * * *

(g) In a given NPSPAC region, channels below 471 listed in Tables 2 and 4B which are vacated by licensees relocating to channels 551–830 and which remain vacant after band reconfiguration will be available as indicated in § 90.617(g)(1 through 3). The only exception will be for the counties listed in § 90.614(c). At locations greater then 113 km (70 mi) from the center city coordinates of Atlanta, GA within the counties listed in § 90.614(c), the channels listed in Tables 2A and 4C which are vacated by licensees relocating to channels 411–830 and which remain vacant after band reconfiguration will be available as indicated in § 90.617(g)(1 through 3). At locations within 113 km (70 mi) of the center city coordinates of Atlanta, GA, the channels listed in Tables 2B and 4D which are vacated by licensees relocating to channels 411–830 and which remain vacant after band reconfiguration will be available as follows:

(1) Only to eligible applicants in the Public Safety Category until three years after the release of a public notice announcing the completion of band reconfiguration in that region;

(2) Only to eligible applicants in the Public Safety or Critical Infrastructure Industry Categories from three to five years after the release of a public notice announcing the completion of band reconfiguration in that region;

(3) Five years after the release of a public notice announcing the completion of band reconfiguration in that region, these channels revert back to their original pool categories.

(h) In a given 800 MHz NPSPAC region—except for the counties listed in § 90.614(c)—channels below 471 listed in Tables 2 and 4B which are vacated by a licensee relocating to channels 511–550 and remain vacant after band reconfiguration will be available as follows:

(1) Only to eligible applicants in the Public Safety Category until three years after the release of a public notice announcing the completion of band reconfiguration in that region;

(2) Only to eligible applicants in the Public Safety or Critical Infrastructure Industry Categories from three to five years after the release of a public notice announcing the completion of band reconfiguration in that region;

(3) Five years after the release of a public notice announcing the completion of band reconfiguration in that region, these channels revert back to their original pool categories.

* * * * *

[FR Doc. E7–14099 Filed 7–19–07; 8:45 am]

BILLING CODE 6712–01–P

## DEPARTMENT OF ENERGY

### 48 CFR Part 970

[Docket No. E7–10037]

RIN 1991–AB67

### Acquisition Regulation: Implementation of DOE's Cooperative Audit Strategy for Its Management and Operating Contracts; Correction

**AGENCY:** Office of Procurement and Assistance Management, Department of Energy.

**ACTION:** Correcting amendments.

**SUMMARY:** This document corrects a final rule (FR document E7–10037), which was published in the **Federal Register** of Thursday, May 24, 2007 (72 FR 29077), regarding the Acquisition Regulation: Implementation of DOE's Cooperative Audit Strategy for Its Management and Operating Contracts. This correction revises the date of the clause at 48 CFR 970.5203–1.

**DATES:** *Effective date:* July 20, 2007.

**FOR FURTHER INFORMATION CONTACT:** Helen Oxberger, (202) 287–1332, e-mail: *Helen.oxberger@hq.doe.gov*.

**SUPPLEMENTARY INFORMATION:**

### Background

The Department of Energy (DOE) in the final regulation that is the subject of this correction amended its Acquisition Regulation (DEAR) by making minor amendments to existing contractor internal audit requirements, through the use of the Cooperative Audit Strategy.

### Need for Correction

This correction revises the date of the clause at 48 CFR 970.5203–1.

### List of Subjects in 48 CFR Part 970

Government procurement.

■ Accordingly, 48 CFR part 970 is corrected by making the following correcting amendment:

## PART 970—DOE MANAGEMENT AND OPERATING CONTRACTS

■ 1. The authority citation for part 970 continues to read as follows:

**Authority:** 42 U.S.C. 2201, 2282a, 2282b, 2282c; 42 U.S.C. 7101 *et seq.*; 41 U.S.C. 418b; 50 U.S.C. 2401 *et seq.*

### 970.5203–1 [Corrected]

■ 2. Section 970.5203–1 is amended by revising the date of the clause to read ''(JUNE 2007)''.

Issued in Washington, DC, on July 16, 2007.

**Edward R. Simpson,**

*Director, Office of Procurement and Assistance Management, Department of Energy.*

**David O. Boyd,**

*Director, Office of Acquisition and Supply Management, National Nuclear Security Administration.*

[FR Doc. E7–14060 Filed 7–19–07; 8:45 am]

BILLING CODE 6450–01–P

# Proposed Rules

Federal Register
Vol. 72, No. 139
Friday, July 20, 2007

This section of the FEDERAL REGISTER contains notices to the public of the proposed issuance of rules and regulations. The purpose of these notices is to give interested persons an opportunity to participate in the rule making prior to the adoption of the final rules.

## DEPARTMENT OF AGRICULTURE

### Grain Inspection, Packers and Stockyards Administration

### 7 CFR Chapter VIII

**RIN 0580–AB00**

### The Role of USDA in Differentiating Grain Inputs for Ethanol Production and Standardizing Testing of the Co-Products of Ethanol Production

**AGENCY:** Grain Inspection, Packers and Stockyards Administration, USDA.

**ACTION:** Advance notice of proposed rulemaking.

**SUMMARY:** We are inviting comments from producers, handlers, processors, livestock feeders, industry representatives, and other interested persons on the appropriate government role with regard to differentiating grain attributes for ethanol conversion, as well as standardizing the testing of co-products of ethanol production, commonly referred to as distillers grains. We have monitored the development of this expanding industry and believe now is an appropriate time to seek input from stakeholders in order to foster collaboration among segments of this industry and support the marketing of ethanol co-products.

**DATES:** We will consider comments that we receive by September 18, 2007.

**ADDRESSES:** We invite you to submit comments on this advance notice of proposed rulemaking. You may submit comments by any of the following methods:

- *E-Mail:* Send comments via electronic mail to *comments.gipsa@usda.gov.*
- *Mail:* Send hardcopy written comments to Tess Butler, GIPSA, USDA, 1400 Independence Avenue, SW., Room 1647–S, Washington, DC 20250–3604.
- *Fax:* Send comments by facsimile transmission to: (202) 690–2755.
- *Hand Delivery or Courier:* Deliver comments to: Tess Butler, GIPSA, USDA, 1400 Independence Avenue, SW., Room 1647–S, Washington, DC 20250–3604.
- *Federal eRulemaking Portal:* Go to *http://www.regulations.gov.* Follow the online instructions for submitting comments.
- *Instructions:* All comments should make reference to the date and page number of this issue of the **Federal Register**.
- *Read Comments:* All comments will be available for public inspection in the above office during regular business hours (7 CFR 1.27 (b)).

**FOR FURTHER INFORMATION CONTACT:** Eric Jabs at GIPSA, USDA, 6501 Beacon Drive, Suite 180 Stop 1404, Kansas City, MO 64133; Telephone (816) 823–4635; Fax Number (816) 823–4644; e-mail *Eric.J.Jabs@usda.gov.*

**SUPPLEMENTARY INFORMATION:**

### Executive Order 12866

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

### Background

The modern fuel ethanol industry uses cereal grains, such as corn, sorghum, and wheat, to convert the starch in the seeds to ethanol by fermentation and distillation. GIPSA has followed the growth of this industry for several years, focusing on utilization of grains, the subsequent impact on supply, and the development of markets for the co-product known as distillers grains. Expansion of the fuel ethanol industry is driven, among other things, by the Energy Policy Act of 2005 (42 U.S.C. 15801) which mandates that 7.5 billion gallons of renewable fuels are utilized by 2012 (which has had a bullish impact on corn prices), the relationship between ethanol prices and crude oil futures, and overall profitability in the ethanol sector. At the beginning of 2007, there were 110 bio-refineries or ethanol plants on-line in 19 States with an annual capacity of 5.5 billion gallons. Seventy-three refineries were under construction and eight were expanding, creating an additional 6 billions gallons of production capacity by 2009. Corn is currently the primary grain for ethanol production (more than 95 percent). In calendar year 2006, 1.8 billion bushels of corn produced 4.9 billion gallons of ethanol and 12 million metric tons of distillers grains. In calendar year 2006, the United States exported 1.25 million metric tons of distillers dried grains (DDG), primarily to Mexico, the European Union, Canada, Japan, Taiwan, and others.

Distillers grains are typically marketed to feed formulators for livestock feeding, primarily beef, dairy, pork, and poultry. Most U.S. ethanol plants are located in reasonable proximity to animal feeding operations to aid logistics. When used locally, the distillers grains move by truck and are sold on a ''wet'' (50–65 percent moisture content) basis, which saves the cost of drying. Distillers grains may move by rail, either to feedlots or to export facilities. In this case, DDG have a moisture content of about 11–12 percent and 75–80 percent of distillers grains are sold this way. One bushel of corn produces approximately 2.8 gallons of ethanol and 17 pounds of distillers grains.

The grains used for ethanol production are standardized in 7 CFR Part 810. Unless exported, there is no requirement for those grains to be officially inspected. The Association of American Feed Control Officials (AAFCO) has developed definitions for distillers grains as provided in their 2006 Official Publication. Section 27 of the Feed Ingredient Definitions provides definitions for Corn Distillers Dried Grains (DDG), Corn Distillers Dried Grains with Solubles (DDGS), Corn Distillers Wet Grains (DWG) and Corn Condensed Distillers Solubles (CDS). (2006 Official Publication, Association of American Feed Control Officials Incorporated. Sharon Krebs, Editor. Oxford, IN. 2006. Distillers Products, pages 273–274.)

### Trading Without Federal Standards

There are well developed markets for by-products of standardized grain which trade without government participation. Examples include soybean meal, soybean oil, and brewers spent grains. In the soybean meal market, the National Oilseed Processors Association (NOPA) established trading rules in 1933, which were last revised in February 2007. The rules serve as guides, and parties to trades are free to adopt, modify, or disregard the rules. These rules govern sampling, testing, and specifications for soybean meal.

Soybean meal trades on the Chicago Board of Trade, and the standard specifications for deliverable grade define specified levels of protein, fat, fiber and moisture content. Unlike distillers grains which are highly variable, soybean meal is very consistent because one processing method is used almost exclusively.

**Testing Grain**

We contacted industry participants and heard that price was the focal point for ethanol processors, while grain quality and timing of deliveries were also of concern. Basic quality factors a processor might consider when sourcing grain include moisture content, protein content, and mycotoxins (aflatoxins in corn for example) content. Additional factors for testing might include some aspect of starch quality, nutrient composition, crude fat, crude fiber; a test to differentiate a grain specifically designed for ethanol conversion, such as grain with a high total fermentable starch content; or an end-use trait, such as a specific amino acid characteristic. Many processors indicated that co-product quality was of concern when sourcing grain, and most processors have grain inspected, either in-house or by contract with an independent laboratory. Conversion of grain to ethanol consumes the starch and leaves the remainder of the grain as the co-product. As a general rule, conversion results in a three-fold concentration in the residual material (i.e., protein, fat, or mycotoxins) in the distillers dried grains. Aflatoxin, Deoxynivalenol, Fumonisins, Zearalenone, and T2 Toxin are mycotoxins that can be present in distiller's grains by-products if the grain delivered to the ethanol plant is contaminated. Mycotoxins are not destroyed during the ethanol production process and are not destroyed during the drying process to produce distillers grains co-products.

**Definitions and Standardization of Testing for Distillers Grains**

While we heard from industry participants that at this time there is no need for GIPSA to establish grading standards for distillers grains (but we might have a role in minimizing market inefficiencies caused by inconsistent testing, either through standardization or validating tests used by the market), others have asked that we at least consider whether there is a need for official standards. Some stakeholders told us they do not feel that current industry-based definitions adequately describe the products.

Alternately, an industry working group, including the American Feed Industry Association (AFIA), the Renewable Fuels Association, and the National Corn Growers Association, states that the current definitions adequately define the distillers products of today, preferring a broad definition. Further, the working group stated that the AFIA Ingredient Guidelines should be considered for updating to address modern processing technologies.

The industry working group also evaluated empirical methods of analyses for Distillers Dried Grains with Solubles (DDGS) for which ''there are no guidelines or recommendations on which analytical test methods should be used * * *'', focusing on analytical methods for moisture, crude protein, crude fat and crude fiber. DDGS currently accounts for about half of the distillers grains industry volume.

**Potential Role for GIPSA**

GIPSA facilitates the marketing of livestock, poultry, meat, cereals, oilseeds, and related agricultural products, and promotes fair and competitive trading practices for the overall benefit of consumers and American agriculture. We facilitate the marketing of U.S. grains and oilseeds by establishing standards for quality assessments, regulating handling practices, and managing a network of Federal, State, and private laboratories that provide impartial, user-fee funded official inspection and weighing services. Recognizing that sampling is the single largest source of error in the analysis of grains, we offer sampling guidelines to the grain handling industry. Finally, for grains and commodities which are not standardized (e.g., hulless oats, popcorn, corn gluten feed), we provide official procedures for analysis of specific factors.

As agricultural crops evolve and varieties with enhanced traits are developed, reliable tests must be developed to quantify the quality traits important to the market. Rapid tests and test kits are evaluated that detect biotechnology derived grains and oil seeds, analyze protein, moisture, oil, and mycotoxins. With the development of such new testing procedures, reference methods are needed to validate and improve their accuracy. This is an area where GIPSA has experience and expertise, which may prove valuable in this instance.

Objective grain/co-product quality assessments (official and unofficial) require reliable, well-standardized measurement methods. Inspection methods can be classified as reference (direct) methods or secondary (indirect) methods. Reference methods are those that ''define'' the quantity or quality in question. To provide the market with rapid, cost-effective quality assessments, GIPSA develops secondary or rapid methods, based on national reference methods, for routine inspection use in the official system. These secondary methods make physical, chemical, electronic, and/or optical measurements related to the desired quality characteristics. GIPSA conducts research to develop, evaluate, and improve reference methods and secondary methods for grain and grain product quality analysis to better meet global grain inspection and marketing needs.

In 2001, we took a new approach in response to the market's need for testing the products of agricultural biotechnology. We established a voluntary proficiency program to organizations testing for biotechnology-derived grains and oilseeds to improve the reliability of testing. We also evaluate the performance of rapid tests developed to detect biotechnology-derived grains and oilseeds and mycotoxins, and confirm the tests operate in accordance with the manufacturers' claims.

GIPSA is issuing this advance notice of proposed rulemaking to invite comments from all interested persons on how we can best facilitate the marketing of distillers grains in today's evolving marketplace. We are seeking comment on market needs and the feasibility and desirability of GIPSA's programs to facilitate the marketing of these products. All interested persons are encouraged to comment on the following issues related to this notice:

1. What should GIPSA's role, if any, be in standardizing the testing of inputs and outputs of ethanol co-product processing?

2. What factors are currently assessed on the input grains for ethanol conversion? Please list the factors by specific grain. What other factors would you test input grain for, if a test were available?

3. What analytes or factors are currently assessed on co-products of ethanol production? Please list the factors by specific co-product type. What other factors would you test for, if a test were available?

4. The industry lacks agreement on reference methods for analysis of co-product attributes. Should GIPSA play a role in the standardization of reference methods? If so, what should that role be?

5. Secondary or rapid methods are used by the official inspection system to determine product quality. Should GIPSA play a role in the validation or

standardization of secondary or rapid methods? Should we limit our participation to validating the performance of test kits? Are there rapid tests in existence other than test kits of which you are aware?

6. Should we work on developing reference methods for tests of specific traits in grains, such as fermentable starch content? Should GIPSA pursue standardized, secondary tests for the presence of specific traits in grains, such as fermentable starch content?

7. Are co-products of ethanol production considered cereal products, according to the European Union regulations (COMMISSION REGULATION (EC) No 856/2005) for mycotoxin limits in cereals and cereal products? Should GIPSA validate the performance of test kits for the detection of mycotoxins in distillers grains? If so, what are the limits of detection which should be considered?

We welcome your comments on these issues as well as any comments or suggestions related to distillers grains.

**Authority:** 7 U.S.C. 71–87.

**David R. Shipman,**

*Acting Administrator, Grain Inspection, Packers and Stockyards Administration.*

[FR Doc. E7–14018 Filed 7–19–07; 8:45 am]

BILLING CODE 3410–KD–P

## DEPARTMENT OF AGRICULTURE

### Grain Inspection, Packers and Stockyards Administration

### 7 CFR Part 810

**RIN 0580–AA96**

### Request for Public Comment on the United States Standards for Soybeans

**AGENCY:** Grain Inspection, Packers and Stockyards Administration, USDA.

**ACTION:** Advance notice of proposed rulemaking; extension of comment period.

**SUMMARY:** We published an advance notice of proposed rulemaking in the **Federal Register** on May 1, 2007, (72 FR 23775), initiating a review of the United States Standards for Soybeans to determine their effectiveness and responsiveness to current grain industry needs. The notice provided an opportunity for interested parties to forward written comments to GIPSA until July 2, 2007. As a result of a request from the soybean industry, we are reopening the comment period to provide interested parties with additional time in which to comment.

**DATES:** We will consider comments that we receive by August 20, 2007.

**ADDRESSES:** We invite you to submit comments on this advance notice of proposed rulemaking. You may submit comments by any of the following methods:

- *E-Mail:* Send comments via electronic mail to *comments.gipsa@usda.gov*
- *Mail:* Send hardcopy written comments to Tess Butler, GIPSA, USDA, 1400 Independence Avenue, SW., Room 1647–S, Washington, DC 20250–3604
- *Fax:* Send comments by facsimile transmission to: (202) 690–2755
- *Hand Delivery or Courier:* Deliver comments to: Tess Butler, GIPSA, USDA, 1400 Independence Avenue, SW., Room 1647–S, Washington, DC 20250–3604.
- *Federal eRulemaking Portal:* Go to *http://www.regulations.gov.* Follow the online instructions for submitting comments.
- *Instructions:* All comments should make reference to the date and page number of this issue of the **Federal Register**.
- *Read Comments:* All comments will be available for public inspection in the above office during regular business hours (7 CFR 1.27(b)).

**FOR FURTHER INFORMATION CONTACT:** Marianne Plaus at GIPSA, USDA, 1400 Independence Avenue, SW., Washington, DC 20250–3630; Telephone (202) 720–0228; Fax Number (202) 720–1015; e-mail *Marianne.Plaus@usda.gov.*

**SUPPLEMENTARY INFORMATION:** GIPSA published an advance notice of proposed rulemaking in the **Federal Register** on May 1, 2007, (72 FR 23775) with the intent to obtain public comment on the United States Standards for Soybeans (7 CFR Part 810). Our intent is, through the comments, to determine their effectiveness and responsiveness to current grain industry needs. The comment period of 60 days from the date of publication closed on July 2, 2007. GIPSA received a request from the soybean industry to provide interested parties additional time to comment. As a result, the comment period is reopened for a 30 day period.

**Authority:** 7 U.S.C. 71–87.

**Alan Christian,**

*Acting Administrator, Grain Inspection, Packers and Stockyards Administration.*

[FR Doc. E7–14017 Filed 7–19–07; 8:45 am]

BILLING CODE 3410–KD–P

## COMMODITY FUTURES TRADING COMMISSION

### 17 CFR Parts 40 and 41

**RIN 3038–AC44**

### Confidential Information and Commission Records and Information

**AGENCY:** Commodity Futures Trading Commission.

**ACTION:** Notice of proposed rulemaking.

**SUMMARY:** The Commodity Futures Trading Commission is proposing to amend the procedures for confidential treatment requests by derivatives transaction execution facilities (DTEF), derivatives clearing organizations (DCO), or designated contract markets (DCM) for products and rules submitted via certification procedures or for Commission review and approval. The proposed rules will provide the exclusive means of requesting confidential treatment for product and rule submissions filed under Parts 40 and 41 of the Commission's regulations. Specifically, DCMs, DTEFs, and DCOs will be required to follow the customary procedures of requesting confidential treatment of information submitted to the Commission except: The submitter also will be required to file a detailed written justification simultaneously with the request for confidential treatment; and the submitter will be required to segregate the material deemed confidential in an appendix to the submission. Additionally, Commission staff may make an initial determination to grant or deny confidential treatment to such material before receiving a request under the Freedom of Information Act (FOIA). The Commission is proposing these amendments to expedite the confidential treatment review process and consequently allow the Commission to provide the public with more immediate access to non-confidential information.

**DATES:** Submit comments on or before August 20, 2007.

**ADDRESSES:** You may submit comments by any of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov.*
- *Mail/Hand Deliver:* Eileen A. Donovan, Acting Secretary of the Commission, Commodity Futures Trading Commission, Three Lafayette Centre, 1155 21st Street, NW., Washington, DC 20581.
- *E-mail: secretary@cftc.gov.*

**FOR FURTHER INFORMATION CONTACT:** Riva Adriance, Deputy Director for Market Review, (202) 418–5494; or David

Steinberg, Attorney Advisor, (202) 418–5102, Division of Market Oversight, Commodity Futures Trading Commission, Three Lafayette Centre, 1155 21st Street, NW., Washington, DC 20581. Electronic mail: *radriance@cftc.gov* or *dsteinberg@cftc.gov.* This document is also available at *http://www.regulations.gov.*

**SUPPLEMENTARY INFORMATION:**

## I. Background

### *A. Overview*

During the past two years, the Commission has observed an increase in the number of registered entity filings submitted under Parts 40 and 41 of the Commission's regulations that are accompanied by a request for confidential treatment.[1] Most of these requests for confidential treatment have been submitted to the Commission in connection with market maker incentive plans.[2] Under current regulation 145.9(d)(10), when the Commission receives a request for confidential treatment for material submitted to the Commission, no determination with respect to any request for confidential treatment will be made until the Commission receives a FOIA request for the subject material. After receipt of the FOIA request, Commission Regulation 145.9(e)(1) generally requires the Assistant Secretary of the Commission to notify the submitter that the Commission received a FOIA request for material subject to the request for confidential treatment.[3] In most cases, the Assistant Secretary also requests that the submitter file a detailed written justification of the confidential treatment request within ten business days.[4]

As a result, both the requirement that a FOIA request must be received to trigger the confidentiality review and the need for submission of a detailed written justification delays the Commission's ability to make a timely confidentiality determination as to whether any information should be made public. Furthermore, in some cases, the Commission never receives a FOIA request for the subject material, which prevents the Commission from moving forward with the confidential treatment review process. While the Commission recognizes limited circumstances where a registered entity filing a submission under Parts 40 and 41 may be entitled to confidential treatment, the Commission has a history of generally making certified rules and products and other rule submissions public and, furthermore, for DCMs, Designation Criterion 7 and Core Principle 7 often require such publication.[5]

### *B. Freedom of Information Act*

The Freedom of Information Act, 5 U.S.C. 552, provides generally that the public has a right of access to federal agency records except to the extent such records, or portions of them, are protected from disclosure by one (or more) of nine exemptions. A submitter requesting confidential treatment must request in writing that the Commission afford confidential treatment under FOIA for any information submitted to the Commission while specifying the grounds on which confidential treatment is being requested.[6] A registered entity typically asserts that the information submitted to the Commission should be exempt from disclosure pursuant to FOIA exemption (b)(4), 5 U.S.C. 552 (b)(4), because the release of such information will cause competitive harm to the submitter.[7] Commission Regulation 145.9 sets forth the procedures that a submitter of information to the Commission must follow in order to obtain confidential treatment for such information. That same provision, however, also permits the Commission to specify ''alternative procedures'' for ''a particular study, report, investigation, or other matter.'' [8] Consistent with that authority, the Commission is proposing to specify alternative procedures for processing requests for confidential treatment of registered entity filings submitted under Parts 40 and 41 of the Commission's regulations.

## II. Proposed Amendments

### *A. Procedures for Requesting Confidential Treatment Under Parts 40 and 41*

The Commission is proposing to add paragraph (c) to Commission Regulation 40.8 to list the procedures that a registered entity must follow when filing a request for confidential treatment. Section 40.8(c) would provide the exclusive method of requesting confidential treatment for information required to be filed under Parts 40 and 41. In addition, the proposal would add new regulations 40.2(a)(3)(iv), 40.6(a)(3)(vi), 41.23(a)(7), and 41.24(a)(6) and amend regulations 40.3(a)(7) and 40.5(a)(8) to direct the

---

[1] A registered entity is defined under Section 1a(29) of the Commodity Exchange Act (Act) as a DCM under Section 5 of the Act (including Section 5f), a DTEF registered under Section 5a of the Act, and a DCO registered under Section 5b of the Act. (Section 5f of the Act, along with Part 41 of the Commission's regulations, establishes requirements for national securities exchanges, national securities associations and alternative trading systems registered with the Securities and Exchange Commission to notice register with the Commission in order to list security futures products (i.e., futures on a single equity security and futures on narrow-based security indexes)).

[2] Market maker incentive plans are created by a registered entity to increase volume of trading and liquidity, typically for new product launches or in markets that for other reasons have low trading volume. In general, registered entities have requested confidential treatment for the name of the market maker(s), the compensation provided by the registered entity to the market maker(s), trade priorities (i.e., percentage of the order flow), and the bid/ask spread level.

[3] Commission Regulation 145.9(e)(1) provides that if the Assistant Secretary or his or her designee determines that a FOIA request seeks material for which confidential treatment has been requested pursuant to regulation 145.9, the Assistant Secretary or his or her designee shall require the submitter to file a detailed written justification of the confidential treatment request within ten business days (unless under regulation 145.9(d)(7) an extension of time has been granted) of that determination unless, pursuant to an earlier FOIA request, a prior determination to release or withhold the material has been made, the submitter has already provided sufficient information to grant the request for confidential treatment, or the material is otherwise in the public domain.

[4] Commission Regulation 145.9(d)(7).

[5] The Commission has been publishing rule submissions on the Commission's website since August of 2003. Prior to this date, Commission staff had consistently determined that submissions filed pursuant to Section 5a(a)(12) of the Act were public, and, pursuant to Appendix A(b)(3) or Part 145, rule filings submitted under Section 5a(a)(12) were made available in the Commission's reading room. Section 5a(a)(12) was removed from the Act with the passage of the Commodity Futures Modernization Act of 2000 (CFMA). As a result, the Commission amended Appendix A (b)(3) to Part 145. Current Appendix A (b)(3) to Part 145 requires the Office of the Secretariat to make registered entity filings relating to rules as defined in Commission Regulation 40.1 available to the public unless the filing is covered by a request for confidential treatment. *See* 69 FR 67503–67508 (November 18, 2004). The Commission believes the submissions now filed under Sections 5c(c)(1) and 5c(c)(2) of the Act should, except in limited circumstances, continue to be made publicly available as they generally do not cause any competitive harm to the registered entity.

[6] Commission Regulation 145.9(d)(1).

[7] Exemption (b)(4) of FOIA protects trade secrets and commercial or financial information obtained from a person that is privileged or confidential. See also Commission Regulation 145.9(d)(ii). Commission Regulation 145.9(d) provides other grounds for non-disclosure of information, including information that: (1) Is specifically exempted by a statute that either requires that the matters be withheld from the public so as to leave no discretion on the issue or establishes particular criteria for withholding or refers to particular types of matters to be withheld; (2) would constitute a clearly unwarranted invasion of the submitter's personal privacy; (3) would reveal investigatory records compiled for law enforcement purposes whose disclosure would constitute an unwarranted invasion of the personal privacy of the submitter; and (4) would reveal investigatory records for law enforcement purposes when disclosure would interfere with enforcement proceedings or disclose investigative techniques and procedures, provided that the claim may be made only by a designated contract market or registered futures association with regard to its own investigatory records.

[8] Commission Regulation 145.9(b).

registered entity requesting confidential treatment to follow the new procedures specified in Commission Regulation 40.8(c). Proposed regulation 40.8(c) would further require the registered entity to follow the procedures in Commission Regulation 145.9 except that: (1) A detailed written justification of the confidential treatment request must be filed simultaneously with the submission; and (2) the material deemed confidential must be filed in an appendix to the request. Finally, the proposed rules would allow Commission staff to make an initial determination to grant or deny confidential treatment before receiving a FOIA request for the subject material.

The requirement that a registered entity follow the procedures in proposed new regulation 40.8(c) would address the absence of guidance in the Commission's regulations for a registered entity when filing a ''reasonable justification'' along with the request for confidential treatment for submissions filed under Parts 40 and 41. The proposed rules would remove the reasonable justification requirement from Commission Regulations 40.3(a)(7) and 40.5(a)(8) and direct the submitter to follow the procedures of regulation 40.8(c) with the filing of the detailed written justification.[9] Additionally, the requirement that the registered entity simultaneously file the detailed written justification with the request for confidential treatment would eliminate the ten-business-day period permitted under regulation 145.9(e)(1) for the submitter to file the detailed written justification after receiving notice that a FOIA request has been received by the Commission. With these changes, the Commission would be able to conduct a thorough analysis of the detailed written justification without delay and weigh, in a more deliberate manner, the potential harm in releasing any portion of the submission against allowing the public to have more timely access to the non-confidential information.

The proposed rules would not affect the ability of the submitter to object to the denial of a confidential treatment request. Thus, the submitter would still be able to file an appeal of any adverse determination with the Commission's Office of the General Counsel.[10] The Commission also notes that a determination that any part of the request for confidential treatment should be granted may be reconsidered if a FOIA request is received by the Commission for the subject material.

The proposed rule requiring material deemed confidential to be placed in an appendix to the submission would enable the Commission to make the non-confidential information available to the public as soon as it receives the submission. The Commission has observed that registered entities requesting confidential treatment sometimes ask for confidentiality for the entire submission. When this happens, the Commission is unable to make any part of the submission immediately available to the public, even when it is clear that information contained in the filing is not confidential and, furthermore, for DCMs, such publication may be required under Designation Criterion 7 and Core Principle 7.[11]

For example, during the past year, Commission staff has contacted certain registered entities that requested confidential treatment for submissions containing market maker incentive plans and requested that they amend their original submissions by placing the confidential information in an appendix. This has enabled the Commission to make the underlying submissions containing the non-confidential information available to the public. The registered entities have been receptive to these requests. Based upon this experience, the Commission does not believe its proposed amendments would place an undue burden on registered entities requesting confidential treatment. Registered entities are consequently on notice that requests for confidential treatment may only cover the appendix to the submission while the underlying submission would be made immediately available to the public.

*B. Public Availability of Terms and Conditions of Products and Mechanisms for Executing Transactions on or Through the Facilities of the Contract Market*

The terms and conditions of contracts must be made available to market authorities, market participants, and the public by the DCM under Section 5(d)(7) of the Act.[12] Regulations 40.3(a)(7) and 40.5(a)(8) currently provide that a product's terms and conditions, as contained in contents of a filing of a submission to the Commission, are publicly available at the time of their submission. The Commission believes the requirement that a product's terms and conditions be publicly available at the time of submission also applies to submissions containing terms and conditions that are filed under regulations 40.2, 40.6, 41.23, and 41.24. In an effort to create a more logical placement in the Commission's regulations for the public availability of a product's terms and conditions, the Commission proposes to relocate this provision to new paragraph 40.8(d) under the Availability of Public Information section of Part 40. This would ensure that registered entities are fully aware, and the public would be on notice that this information is available.

The mechanisms for executing transactions on or through the facilities of the contract market must also be made available to market authorities, market participants, and the public by the DCM under Section 5(d)(7) of the Act. The Commission proposes adding language to new paragraph 40.8(d) to make clear to registered entities that this information is public and to inform the

[9] 67 FR 62873–62880 (October 9, 2002). Amendments to rules 40.3 and 40.5 (which require the registered entity to identify with particularity information in the submission that will be subject to a request for confidential treatment and support the request for confidential treatment with reasonable justification) were made to conform with language in Commission Regulations 37.5(b)(5) and 38.3(a)(5) (which pertain to applicants for DTEF registration and contract market designation, respectively) that required the submitter to include a reasonable justification in support of the request for confidential treatment. However, Commission Regulations 37.5(b)(5) and 38.3(a)(5) were amended by eliminating the reasonable justification requirement. Instead, these regulations now require the applicant to follow the procedures in Commission Regulation 145.9 when requesting confidential treatment. See 69 FR 67811–67817 (November 22, 2004).

[10] Commission Regulation 145.9(g).

[11] The Commission notes that provisions under these Parts may not apply to all registered entities. For example, Section 40.2 applies to all registered entities while 40.3 applies only to DCMs and DTEFs and not DCOs.

[12] 67 FR 62874–75 (Oct. 9, 2002). Product terms and conditions that are made publicly available at the time of their submission to the Commission enable the Commission to obtain the views of market participants and others to ascertain whether the proposed product would be readily susceptible to manipulation, or otherwise violate the Act. Commission staff routinely conduct trade interviews when reviewing novel instruments to ascertain the relative susceptibility of a product to being manipulated. To be meaningful, these interviews require the release of the proposed instrument's terms and conditions. Generally, the Commission intends to continue its long-standing practice of requesting public comment on the terms and conditions of new products under review for Commission approval by publication of notices in the **Federal Register**. In instances where notice in the **Federal Register** is impracticable or otherwise unnecessary, notice of a submission for voluntary approval and of the public availability of the proposed product's terms and conditions will be through the Commission's internet Web site (*http://www.cftc.gov*).

The terms and conditions of products eligible for trading by self-certification will be available from the Commission, at the time that the exchange legally could commence trading—the beginning of the business day following certification to the Commission.

public that this information is also available. The Commission notes that mechanisms for executing transactions on or through the facilities of the contract market generally include such information as trading algorithms and information from an exchange's rulebook that pertain to trading. Moreover, the Commission notes that requests for confidential treatment covering the mechanisms for executing transactions on or through the facilities of the contract market and a product's terms and conditions will not be processed.

## III. Cost-Benefit Analysis

Section 15(a) of the Act, as amended by section 119 of the CFMA, requires the Commission to consider the costs and benefits of its action before issuing a new regulation under the Act. By its terms, section 15(a) as amended does not require the Commission to quantify the costs and benefits of a new regulation or to determine whether the benefits of the regulation outweigh its costs. Rather, section 15(a) simply requires the Commission to ''consider the costs and benefits'' of its action.

Section 15(a) of the Act further specifies that costs and benefits shall be evaluated in light of five broad areas of market and public concern: Protection of market participants and the public; efficiency, competitiveness, and financial integrity of futures markets; price discovery; sound risk management practices; and other public interest considerations. Accordingly, the Commission could, in its discretion, give greater weight to any one of the five enumerated areas and could, in its discretion, determine that, notwithstanding its costs, a particular regulation was necessary or appropriate to protect the public interest or to effectuate any of the provisions or to accomplish any of the purposes of the Act.

The Commission is considering the costs and benefits of these proposed regulations in light of the specified provisions of section 15(a) of the Act:

1. Protection of market participants and the public. The proposed amendments should have no effect on the Commission's ability to protect market participants and the public.

2. Efficiency and competition. The proposed amendments are expected to benefit efficiency by making the non-confidential information from registered entity submissions available to the public in a more timely manner. The Commission anticipates that the costs of compliance with the confidential treatment procedures will be minimal. The proposed amendments should have no effect, from the standpoint of imposing costs or creating benefits, on competition in the futures and options markets.

3. Financial integrity of futures markets and price discovery. The amendments should have no effect, from the standpoint of imposing costs or creating benefits, on the financial integrity or price discovery function of the futures and options markets.

4. Sound risk management practices. The amendments being proposed herein should have no effect on the risk management practices of the futures and options industry.

5. Other public considerations. No additional public considerations could be determined.

After considering these factors, the Commission has determined to propose the rules and rule amendments set forth below. The Commission invites public comment on its application of the cost-benefit provision. Commenters also are invited to submit any data that they may have quantifying the costs and benefits of the proposal with their comment letters.

## IV. Related Matters

### *A. Regulatory Flexibility Act*

The Regulatory Flexibility Act (RFA), 5 U.S.C. 601 *et seq.* (2000), requires federal agencies, in proposing regulations, to consider the impact of those regulations on small entities. The regulations proposed herein would affect derivatives transaction execution facilities, designated contract markets, and derivatives clearing organizations. The Commission has previously determined that the foregoing entities are not small entities for purposes of the RFA.[13] Accordingly, the Acting Chairman, on behalf of the Commission, hereby certifies pursuant to 5 U.S.C. 605(b) that the proposed regulations will not have a significant economic impact on a substantial number of small entities.

### *B. Paperwork Reduction Act of 1995*

This proposed rulemaking contains information collection requirements. As required by the Paperwork Reduction Act (PRA) of 1995 (44 U.S.C. 3504(h)), the Commission has submitted a copy of this section to the Office of Management and Budget (OMB) for its review.

*Collection of Information:* Rules Relating to Part 40, Provisions Common to DCMs, DTEFs, and DCOs, OMB Control Number 3038–0022.

The expected effect of the proposed amended regulations will be to increase the burden previously approved by OMB for this collection of information by 16 hours as it will result in the filing of approximately five additional pages when a registered entity files a detailed written justification and confidential appendix under Commission Regulations 40.2, 40.3, 40.4, 40.5, and 40.6.

The estimated burden was calculated as follows:

*Estimated number of respondents:* 12.

*Annual responses by each respondent:* .30.

*Total annual responses:* 4.

*Estimated average hours per response:* 4.

*Annual reporting burden:* 16.

*Collection of Information:* Rules Relating to Part 41, Security Futures Products, OMB Control Number 3038–0059.

The expected effect of the proposed amended regulations will be to increase the burden previously approved by OMB for this collection of information by 3.6 hours as it will result in the filing of approximately five additional pages when a registered entity files a detailed written justification and confidential appendix under Commission Regulations 41.23 and 41.24.

*Estimated number of respondents:* 3.

*Annual responses by each respondent:* .30.

*Total annual responses:* .90.

*Estimated average hours per response:* 4.

*Annual reporting burden:* 3.6.

Organizations and individuals desiring to submit comments on the information collection requirements should direct them to the Office of Information and Regulatory Affairs, Office of Management and Budget, Room 10202, New Executive Office Building, 725 17th Street, NW., Washington, DC 20503; Attention: Desk Officer for the Commodity Futures Trading Commission.

In compliance with the PRA, the Commission, through these proposed regulations, solicits comments to: (1) Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the Commission, including whether the information will have a practical use; (2) evaluate the accuracy of the Commission's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used; (3) enhance the quality, usefulness, and clarity of the information to be

[13] 47 FR 18618, 18619 (April 30, 1982) discussing contract markets; 66 FR 42256, 42268 (August 10, 2001) discussing exempt boards of trade, exempt commercial markets and derivatives transaction execution facilities; 66FR 45605, 45609 (August 29, 2001) discussing derivatives clearing organizations.

collected; and (4) minimize the burden of collecting 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 responses.

OMB is required to make a decision concerning the collection of information contained in these proposed regulations between 30 and 60 days after publication of this document in the **Federal Register**. Therefore, a comment to OMB is best assured of having its full effect if OMB receives it within 30 days of publication. This does not affect the deadline for the public to comment to the Commission on the proposed regulations. Copies of the information collection submission to OMB are available from the CFTC Clearance Officer, 1155 21st Street, NW., Washington DC 20581, (202) 418–5160.

**List of Subjects**

*17 CFR Part 40*

Commodity futures, Contract markets, Designation application, Reporting and recordkeeping requirements.

*17 CFR Part 41*

Security futures.

For the reasons stated in the preamble, the Commission proposes to amend 17 CFR parts 40 and 41 as follows:

## PART 40—PROVISIONS COMMON TO CONTRACT MARKETS, DERIVATIVES TRANSACTION EXECUTION FACILITIES AND DERIVATIVES CLEARING ORGANIZATIONS

1. The authority for part 40 continues to read as follows:

**Authority:** 7 U.S.C. 1a, 2, 5, 6, 6c, 7, 7a, 8 and 12a, as amended by appendix E of Pub. L. 106–554, 114 Stat. 2763A–365.

2. Section 40.2 is amended by adding paragraph (a)(3)(v) to read as follows:

### § 40.2 Listing products for trading by certification.

(a) * * *

(3) * * *

(v) A request for confidential treatment as permitted under the procedures of § 40.8.

* * * * *

3. Section 40.3 is amended by revising paragraph (a)(7) to read as follows:

### § 40.3 Voluntary submission of new products for Commission review and approval.

(a) * * *

(7) Include a request for confidential treatment as permitted under the procedures of § 40.8.

* * * * *

4. Section 40.5 is amended by revising paragraph (a)(8) to read as follows:

### § 40.5 Voluntary submission of rules for Commission review and approval.

(a) * * *

(8) Include a request for confidential treatment as permitted under the procedures of § 40.8.

* * * * *

5. Section 40.6 is amended by adding new paragraph (a)(3)(vi) to read as follows:

### § 40.6 Self-certification of rules by designated contract markets and registered derivatives clearing organizations.

(a) * * *

(3) * * *

(vi) A request for confidential treatment as permitted under the procedures of § 40.8.

* * * * *

6. Section 40.8 is amended by adding new paragraphs (c) and (d) to read as follows:

### § 40.8 Availability of public information.

* * * * *

(c) A registered entity's filing of new products under the self-certification procedures, new products for Commission review and approval, new rules and rule amendments for Commission review and approval, and new rules and rule amendments submitted under the self-certification procedures will be treated as public information unless covered by a request for confidential treatment. If a registered entity files a request for confidential treatment, the procedures in § 145.9 of this chapter shall apply with the following exceptions:

(1) A detailed written justification of the confidential treatment request must be filed simultaneously with the request for confidential treatment;

(2) The material deemed confidential must be segregated in an appendix to the submission; and

(3) Commission staff may make an initial determination with respect to the request for confidential treatment before receiving a request under the Freedom of Information Act for the material for which confidential treatment is being sought.

(d) A registered entity's filing regarding a product's terms and conditions and the mechanisms for executing transactions on or through the facilities of the contract market will be made publicly available at the time of submission and requests for confidential treatment covering this information will be denied.

## PART 41—SECURITY FUTURES PRODUCTS

7. The authority citation for part 41 continues to read as follows:

**Authority:** Sections 206, 251 and 252, Pub. L. 106–554, 114 Stat. 2763, 7 U.S.C. 1a, 2, 6f, 6j, 7a–2, 12a; 15 U.S.C. 78g(c)(2).

8. Section 41.23 is amended by adding new paragraph (a)(7) to read as follows:

### § 41.23 Listing of security futures products for trading.

(a) * * *

(7) Includes a request for confidential treatment as permitted under the procedures of § 40.8.

* * * * *

9. Section 41.24 is amended by adding new paragraph (a)(6) to read as follows:

### § 41.24 Rule amendments to security futures products.

(a) * * *

(6) Includes a request for confidential treatment as permitted under the procedures of § 40.8.

* * * * *

Issued in Washington, DC, on July 17, 2007 by the Commission.

**Eileen A. Donovan,**

*Acting Secretary of the Commission.*

[FR Doc. E7–14103 Filed 7–19–07; 8:45 am]

BILLING CODE 6351–01–P

---

## AGENCY FOR INTERNATIONAL DEVELOPMENT

## 22 CFR Part 215

**RIN 0412–AA61**

## Privacy Act of 1974, Implementation of Exemptions

**AGENCY:** United States Agency for International Development.

**ACTION:** Proposed rule.

**SUMMARY:** The United States Agency for International Development (USAID) is concurrently establishing a new system of records pursuant to the provisions of the Privacy Act of 1974 (5 U.S.C. 552a), entitled the ''Partner Vetting System'' (PVS). In this proposed rulemaking, USAID proposes to exempt portions of this system of records from one or more provisions of the Privacy Act because of criminal, civil, and administrative enforcement requirements.

**DATES:** Submit comments on or before September 18, 2007.

**ADDRESSES:** You may submit comments, identified by RIN 0412–AA61, by any of the following methods:

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

*Mail:* U.S. Agency for International Development, Chief Privacy Officer, 1300 Pennsylvania Avenue NW., Room 2.12–003, Washington, DC 20523–2120.

*Instructions:* All submissions must include the title of the proposed action, and Regulatory Information Number (RIN) for this rulemaking. Please include your name, title, organization, postal address, telephone number, and e-mail address in the text of the message.

**FOR FURTHER INFORMATION CONTACT:** Jeff Denale, Coordinator for Counterterrorism, Office of Security, United States Agency for International Development, Ronald Reagan Building, 1300 Pennsylvania Avenue, NW., Washington, DC 20523 by phone (202) 712–1264.

**SUPPLEMENTARY INFORMATION:**

## A. Background

In accordance with the Privacy Act of 1974, 5 U.S.C. 552a, USAID is publishing a new system of records notice for the Office of Security named Partner Vetting System (PVS). The PVS will support the vetting of directors, officers, or other employees of non-governmental organizations who apply for USAID contracts, grants, cooperative agreements or other funding and those who apply for registration with USAID as Private Voluntary Organizations. The information collected from these individuals will be used to conduct screening to ensure USAID funds and USAID-funded activities are not purposefully or inadvertently used to provide support to entities or individuals deemed to be a risk to national security. As these individuals and organizations are not employees or job applicants, nor would they be eligible for or require security clearances, traditional employment or security clearance investigative mechanisms are not authorized or appropriate for the stated purposes.

USAID proposes to exempt this system, in part, from certain provisions of the Privacy Act and to add the PVS system to 22 CFR 215.14, Specific Exemptions. USAID needs this exemption in order to protect information related to investigations from disclosure to subjects of investigations and to protect classified information related to the government's national security programs. Specifically, the exemptions are required to preclude subjects of investigations from frustrating the investigative process; to avoid disclosure of investigative techniques; protect the identities and physical safety of confidential informants and of law enforcement personnel; ensure the Office of Security's ability to obtain information from third parties and other sources; protect the privacy of third parties; and safeguard classified information.

Aside form the specific protections afforded classified information that may underpin the screening mechanisms involved, USAID must also protect the names of organizations and individuals within this system. Because the results of screening on any particular organization or individual may be derived from classified and sensitive law enforcement and intelligence information, USAID cannot confirm or deny whether an individual ''passed'' or ''failed'' screening. The nondisclosure of the information protects the government's operational counterterrorism and counterintelligence missions, as well as the personal safety of those involved in counterterrorism investigations.

## B. Regulatory Planning and Review

This is not a significant regulatory action and, therefore, is not subject to review under Section 6(b) of Executive Order 12866, Regulatory Planning and Review, dated September 30, 1993. This rule is not a major rule under 5 U.S.C. 804.

## C. Regulatory Flexibility Act

Pursuant to requirements set forth in the Regulatory Flexibility Act (RFA) (5 U.S.C. 601 *et seq.*), USAID has considered the economic impact of the rule and has determined that its provisions would not have a significant economic impact on a substantial number of small entities.

## D. Paperwork Reduction Act

The Paperwork Reduction Act does apply because the proposed changes impose information collection requirements that require the approval of the Office of Management and Budget under 44 U.S.C. 3501 *et seq.*

## List of Subjects in 22 CFR Part 215

Freedom of Information, Investigations, Privacy.

For the reasons stated in the preamble, the USAID proposes to amend 22 CFR part 215 as follows:

## PART 215—REGULATIONS FOR IMPLEMENTATION OF PRIVACY ACT OF 1974

1. The authority citation for 22 CFR part 215 is revised to read as follows:

**Authority:** Pub. L. 93–579, 88 Stat. 1896 (5 U.S.C. 553, (b), (c) and (e).

2. Amend § 215.13 by adding paragraph (c)(2) to read as follows:

### § 215.13 General exemptions.

* * * * *

(c) * * *

(2) *Partner Vetting System.* This system is exempt from sections (c)(3) and (4); (d); (e) (1), (2), and (3); (e) (4) (G), (H), and (I); (e) (5) and (8); (f), (g), and (h) of 5 U.S.C. 552a. These exemptions are necessary to insure the proper functioning of the law enforcement activity, to protect confidential sources of information, to fulfill promises of confidentiality, to maintain the integrity of the law enforcement procedures, to avoid premature disclosure of the knowledge of criminal activity and the evidentiary bases of possible enforcement actions, to prevent interferences with law enforcement proceeding, to avoid the disclosure of investigative techniques, to avoid endangering the law enforcement personnel, to maintain the ability to obtain candid and necessary information, to fulfill commitments made to sources to protect the confidentiality of information, to avoid endangering these sources, and to facilitate proper selection or continuance of the best applicants or persons for a given position or contract. Although the primary functions of USAID are not of a law enforcement nature, the mandate to ensure USAID funding is not purposefully or inadvertently used to provide support to entities or individuals deemed to be a risk to national security necessarily requires coordination with law enforcement and intelligence agencies as well as use of their information. Use of these agencies' information necessitates the conveyance of these other systems exemptions to protect the information as stated.

3. Amend 22 CFR 215.14 by adding the heading ''Note to paragraph (c)(5)'' to the undesignated text at the end of the section and paragraph (c)(6) to read as follows:

### § 215.14 Specific exemptions.

* * * * *

(c) * * *

(6) *Partner Vetting System.* This system is exempt under 5 U.S.C. 552a (k)(1), (k)(2), and (k)(5) from the provision of 5 U.S.C. 552a (c)(3); (d);

(e)(1); (e)(4) (G), (H), (I); and (f). These exemptions are claimed to protect the materials required by executive order to be kept secret in the interest of national defense of foreign policy, to prevent subjects of investigation from frustrating the investigatory process, to insure the proper functioning and integrity of law enforcement activities, to prevent disclosure of investigative techniques, to maintain the ability to obtain candid and necessary information, to fulfill commitments made to sources to protect the confidentiality of information, to avoid endangering these sources, and to facilitate proper selection or continuance of the best applicants or persons for a given position or contract.

**Philip M. Heneghan,**

*Chief Privacy Officer.*

[FR Doc. 07–3331 Filed 7–19–07; 8:45 am]

**BILLING CODE 6116–01–P**

---

## DEPARTMENT OF THE TREASURY

### Internal Revenue Service

### 26 CFR Part 1

**[REG–143601–06]**

**RIN 1545–BG30**

## Mortality Tables for Determining Present Value; Correction

**AGENCY:** Internal Revenue Service (IRS), Treasury.

**ACTION:** Correction to notice of proposed rulemaking.

**SUMMARY:** This document contains corrections to notice of proposed rulemaking that was published in the **Federal Register** on Tuesday, May 29, 2007 (72 FR 29456) providing mortality tables to be used in determining present value or making any computation for purposes of applying certain pension funding requirements.

**FOR FURTHER INFORMATION CONTACT:** Bruce Perlin, Lauson C. Green, or Linda S.F. Marshall at (202) 622–6090.

**SUPPLEMENTARY INFORMATION:**

### Background

The notice of proposed rulemaking (REG–143601–06) that is the subject of these corrections is under sections 412, 430, and 431 of the Internal Revenue Code.

### Need for Correction

As published, the notice of proposed rulemaking (REG–143601–06) contains errors that may prove to be misleading and are in need of clarification.

### Correction of Publication

Accordingly, the notice of proposed rulemaking (REG–143601–06) that was the subject of FR Doc. 07–2631 is corrected as follows:

1. On page 29457, column 3, in the preamble, line 4 of footnote number 2, the language ''XLVII (1995), p. 819. The RP–2000 Mortality Table'' is corrected to read ''XLVII (1995), p. 819. The RP–2000 Mortality Tables''.

2. On page 29460, column 3, in the preamble, second full paragraph of the column, line 7 from the bottom of the paragraph, the language ''improvement factor is equal to (1—'' is corrected to read ''improvement factor is equal to (1–''.

**§ 1.430(h)(3)–2 [Corrected]**

3. On page 29471, § 1.430(h)(3)–2(d)(4)(i)(E), column 3, last line of the paragraph, the language ''§ 1.430(h)–1(a)(3)).'' is corrected to read ''§ 1.430(h)(3)–1(a)(3)).''

**LaNita Van Dyke,**

*Branch Chief, Publications and Regulations Branch, Legal Processing Division, Associate Chief Counsel (Procedure and Administration).*

[FR Doc. E7–13494 Filed 7–19–07; 8:45 am]

**BILLING CODE 4830–01–P**

---

## DEPARTMENT OF THE TREASURY

### Internal Revenue Service

### 26 CFR Part 1

**[REG–144859–04]**

**RIN 1545–BD72**

## Section 1367 Regarding Open Account Debt; Correction

**AGENCY:** Internal Revenue Service (IRS), Treasury.

**ACTION:** Cancellation of notice of public hearing on proposed rulemaking.

**SUMMARY:** This document cancels a public hearing on proposed regulations under section 1367 of the Internal Revenue Code relating to the treatment of open account debt between S corporations and their shareholders.

**DATES:** The public hearing, originally scheduled for July 31, 2007, at 10 a.m., is cancelled.

**FOR FURTHER INFORMATION CONTACT:** Richard A. Hurst of the Publications and Regulations Branch, Legal Processing Division, Associate Chief Counsel (Procedure and Administration), at *Richard.A.Hurst@irscounsel.treas.gov.*

**SUPPLEMENTARY INFORMATION:** A notice of public hearing that appeared in the **Federal Register** on Thursday, April 12, 2007 (72 FR 18417), announced that a public hearing was scheduled for July 31, 2007, at 10 a.m., in the IRS Auditorium, Internal Revenue Building, 1111 Constitution Avenue, NW., Washington, DC. The subject of the public hearing is under section 1367 of the Internal Revenue Code.

The public comment period for these regulations expired on July 11, 2007. The notice of proposed rulemaking and notice of public hearing instructed those interested in testifying at the public hearing to submit a request to speak and an outline of the topics to be addressed. As of Tuesday, July 17, 2007, no one has requested to speak. Therefore, the public hearing scheduled for July 31, 2007, is cancelled.

**LaNita Van Dyke**

*Chief, Publications and Regulations Branch, Legal Processing Division, Associate Chief Counsel (Procedure and Administration).*

[FR Doc. E7–14082 Filed 7–19–07; 8:45 am]

**BILLING CODE 4830–01–P**

---

## DEPARTMENT OF THE TREASURY

### Internal Revenue Service

### 26 CFR Part 1

**[REG–103842–07]**

**RIN 1545–BG33**

## Qualified Films Under Section 199; Correction

**AGENCY:** Internal Revenue Service (IRS), Treasury.

**ACTION:** Correction to notice of proposed rulemaking.

**SUMMARY:** This document contains corrections to a notice of proposed rulemaking that was published in the **Federal Register** on Thursday, June 7, 2007 (72 FR 31478). These regulations involve the deduction for income attributable to domestic production activities under section 199 and affect taxpayers who produce qualified films under section 199(c)(4)(A)(i)(II) and (c)(6) and taxpayers who are members of an expanded affiliated group under section 199(d)(4).

**FOR FURTHER INFORMATION CONTACT:** Concerning § 1.199–3(k) of the proposed regulations, David McDonnell at (202) 622–3040; Concerning § 1.199–7 of the proposed regulations, Ken Cohen (202) 622–7790 (not toll-free numbers).

**SUPPLEMENTARY INFORMATION:**

### Background

The notice of proposed rulemaking (REG–103842–07) that is the subject of the correction is under section 199 of the Internal Revenue Code.

### Need for Correction

As published, the notice of proposed rulemaking (REG–103842–07) contains errors that may prove to be misleading and are in need of clarification.

### Correction of Publication

Accordingly, the publication of the notice of proposed rulemaking (REG–103842–07), that is the subject of FR Doc. E7–10821, is corrected as follows:

1. On page 31480, column 2, in the preamble, under the paragraph heading ''*Expanded Affiliated Groups*'', second paragraph of the column, lines 25 through 28, the language ''assume that X and Y each have $60 of taxable income and QPAI in 2007, Z has $170 of taxable income and QPAI in 2008, and that X, Y, and Z each have'' is corrected to read ''assume that X and Y each has $60 of taxable income and QPAI in 2007, Z has $170 of taxable income and QPAI in 2008, and that X, Y, and Z each has''.

### § 1.199–3 [Corrected]

2. On page 31482, column 1, § 1.199–3(k)(7)(i), line 2 from the bottom of the paragraph, the language ''Paragraph (g)(4)(ii)(A) of this section'' is corrected to read ''Paragraph (g)(3)(ii)(A) of this section''.

### § 1.199–7 [Corrected]

3. On page 31482, column 3, § 1.199–7(e) *Example 10.* paragraph (i), line 5 of the paragraph, the language ''B each use the section 861 method for'' is corrected to read ''B each uses the section 861 method for''.

4. On page 31482, column 3, § 1.199–7(e) *Example 10.* paragraph (iii), line 8 of the paragraph, the language ''B becomes a non-member of the consolidated'' is corrected to read ''B becomes a nonmember of the consolidated''.

5. On page 31483, column 1, § 1.199–7(g)(3) *Example.* paragraph (i), lines 9 through 11 of the paragraph, the language ''year, neither X, Y, nor Z join in the filing of a consolidated Federal income tax return. Assume that X, Y, and Z each have W–2'' is corrected to read ''year, neither X, Y, nor Z joins in the filing of a consolidated Federal income tax return. Assume that X, Y, and Z each has W–2''.

6. On page 31483, column 1, § 1.199–7(g)(3) *Example.* paragraph (ii), line 5 from the bottom of the column, the language ''allocated $96 of the deduction. For the'' is corrected to read ''allocated $96 of the EAG's section 199 deduction. For the''.

**LaNita Van Dyke,**

*Chief, Publications and Regulations Branch, Legal Processing Division, Associate Chief Counsel (Procedure and Administration).*

[FR Doc. E7–14080 Filed 7–19–07; 8:45 am]

BILLING CODE 4830–01–P

---

## DEPARTMENT OF THE TREASURY

## Internal Revenue Service

## 26 CFR Part 301

**[REG–148951–05]**

**RIN 1545–BF54**

## Change to Office To Which Notices of Nonjudicial Sale and Requests for Return of Wrongfully Levied Property Must Be Sent

**AGENCY:** Internal Revenue Service (IRS), Treasury.

**ACTION:** Notice of proposed rulemaking by cross-reference to temporary regulations.

**SUMMARY:** In the Rules and Regulations section of this issue of the **Federal Register**, the IRS is issuing temporary regulations relating to the discharge of liens under section 7425 and return of wrongfully levied upon property under section 6343 of the Internal Revenue Code (Code) of 1986. Those regulations clarify that such notices and claims should be sent to the IRS official and office specified in the relevant IRS publications. The regulations will affect parties seeking to provide the IRS with notice of a nonjudicial foreclosure sale and parties making administrative requests for return of wrongfully levied property. The text of those regulations also serves as the text of these proposed regulations.

**DATES:** Written or electronic comments and requests for a public hearing must be received by October 18, 2007.

**ADDRESSES:** Send submissions to: CC:PA:LPD:PR (REG–148951–05), Room 5203, Internal Revenue Service, PO Box 7604, Ben Franklin Station, Washington, DC 20044. Submissions may be hand-delivered to CC:PA:LPD:PR (REG–148951–05), Courier's Desk, Internal Revenue Service, 1111 Constitution Avenue, NW., Washington, DC 20224. Alternatively, taxpayers may submit comments electronically to the IRS Internet site via the Federal eRulemaking Portal at *www.regulations.gov* (IRS REG–148951–05).

**FOR FURTHER INFORMATION CONTACT:** Concerning the proposed regulations, Robin M. Ferguson, (202) 622–3610; concerning submissions of comments, the hearing, call Kelly Banks, (202) 622–7180 (not toll-free numbers).

**SUPPLEMENTARY INFORMATION:**

### Background

Temporary regulations in the Rules and Regulations section of this issue of the **Federal Register** contain amendments to the Procedure and Administration Regulations (26 CFR part 301) relating to the giving of notice of nonjudicial sales under section 7425(b) of the Code and requests for return of wrongfully levied property under section 6343(b) of the Code. The text of those regulations also serves as the text of these proposed regulations. The preamble to the temporary regulations explains the temporary regulations and these proposed regulations.

### Proposed Effective Date

These regulations are proposed to apply to any notice of sale filed or request for return of property made after the date that these regulations are published as final regulations in the **Federal Register**.

### Special Analyses

It has been determined that this notice of proposed rulemaking is not a significant regulatory action as defined in Executive Order 12866. Therefore, a regulatory assessment is not required. It also has been determined that section 553(b) of the Administrative Procedure Act (5 U.S.C. chapter 5) does not apply to these regulations, and because the regulations do not impose a collection of information on small entities, the Regulatory Flexibility Act (5 U.S.C. chapter 6) does not apply. Pursuant to section 7805(f) of the Internal Revenue Code, this regulation has been submitted to the Chief Counsel for Advocacy of the Small Business Administration for comment on its impact on small business.

### Comments and Requests for Public Hearing

Before these proposed regulations are adopted as final regulations, consideration will be given to any electronic and written comments (a signed original and eight (8) copies) or electronic comments that are submitted timely to the IRS. The IRS and Treasury Department specifically request comments on the clarity of the proposed rules and how they may be made easier to understand. All comments will be available for public inspection and copying. A public hearing will be scheduled if requested in writing by any person that timely submits written comments. If a public hearing is scheduled, notice of the date, time, and place for the public hearing will be published in the **Federal Register**.

**Drafting Information**

The principal author of these regulations is Robin M. Ferguson, Office of Associate Chief Counsel, Procedure and Administration (Collection, Bankruptcy and Summonses Division).

**List of Subjects in 26 CFR Part 301**

Employment taxes, Estate taxes, Excise taxes, Gift taxes, Income taxes, Penalties, Reporting and recordkeeping requirements.

**Proposed Amendments to the Regulations**

Accordingly, 26 CFR part 301 is proposed to be amended as follows:

## PART 301—PROCEDURE AND ADMINISTRATION

**Paragraph 1.** The authority citation for part 301 continues to read in part as follows:

**Authority:** 26 U.S.C. 7805 * * *

**Par. 2.** Section 301.6343–2 is amended by revising paragraphs (a)(1) introductory text, (b) introductory text, and (e) to read as follows:

**§ 301.6343–2 Return of wrongfully levied upon property.**

(a)(1) [The text of the proposed amendment for § 301.6343–2(a)(1) introductory text is the same as the text of § 301.6343–2T(a)(1) introductory text published elsewhere in this issue of the **Federal Register**].

* * * * *

(b) [The text of the proposed amendment for § 301.6343–2(b) introductory text is the same as the text of § 301.6343–2T(b) introductory text published elsewhere in this issue of the **Federal Register**].

* * * * *

(e) [The text of the proposed amendment for § 301.6343–2(e) is the same as the text of § 301.6343–2T(e) published elsewhere in this issue of the **Federal Register**].

**Par. 3.** Section 301.7425–3 is amended by revising paragraphs (a)(1), (b)(1), (b)(2), (c)(1), (d)(2), (d)(3), and (d)(4), and adding paragraph (e) to read as follows:

**§ 301.7425–3 Discharge of liens; special rules.**

(a) * * * (1) [The text of the proposed amendment for § 301.7425–3(a)(1) is the same as the text of § 301.7425–3T(a)(1) published elsewhere in this issue of the **Federal Register**].

* * * * *

(b) * * * (1) [The text of the proposed amendment for § 301.7425–3(b)(1) is the same as the text of § 301.7425–3T(b)(1) published elsewhere in this issue of the **Federal Register**].

(2) [The text of the proposed amendment for § 301.7425–3(b)(2) is the same as the text of § 301.7425–3T(b)(2) published elsewhere in this issue of the **Federal Register**].

(c) * * * (1) [The text of the proposed amendment for § 301.7425–3(c)(1) is the same as the text of § 301.7425–3T(c)(1) published elsewhere in this issue of the **Federal Register**].

* * * * *

(d) * * * (2) [The text of the proposed amendment for § 301.7425–3(d)(2) is the same as the text of § 301.7425–3T(d)(2) published elsewhere in this issue of the **Federal Register**].

(3) [The text of the proposed amendment for § 301.7425–3(d)(3) is the same as the text of § 301.7425–3T(d)(3) published elsewhere in this issue of the **Federal Register**].

(4) [The text of the proposed amendment for § 301.7425–3(d)(4) is the same as the text of § 301.7425–3T(d)(4) published elsewhere in this issue of the **Federal Register**].

(e) [The text of the proposed amendment for § 301.7425–3(e) is the same as the text of § 301.7425–3T(e) published elsewhere in this issue of the **Federal Register**].

**Kevin M. Brown,**

*Deputy Commissioner for Services and Enforcement.*

[FR Doc. E7–14051 Filed 7–19–07; 8:45 am]

BILLING CODE 4830–01–P

---

## ENVIRONMENTAL PROTECTION AGENCY

## 40 CFR Part 52

**[EPA–R06–OAR–2006–0849; FRL–8442–7]**

## Approval and Promulgation of Implementation Plans; Louisiana; Clean Air Interstate Rule Sulfur Dioxide Trading Program

**AGENCY:** Environmental Protection Agency (EPA).

**ACTION:** Proposed rule.

**SUMMARY:** EPA is proposing to approve a revision to the Louisiana State Implementation Plan (SIP) submitted on September 22, 2006, enacted at Louisiana Administrative Code, Title 33, Part III, Chapter 5, Section 506(C) (LAC 33:III.506(C)). This revision addresses the requirements of EPA's Clean Air Interstate Rule (CAIR) Sulfur Dioxide ($SO_2$) Trading Program, promulgated on May 12, 2005 and subsequently revised on April 28, 2006. EPA is proposing to determine that the SIP revision fully implements the CAIR $SO_2$ requirements for Louisiana. Therefore, as a consequence of the SIP approval, EPA will also withdraw the CAIR Federal Implementation Plan (CAIR FIP) concerning $SO_2$ emissions for Louisiana. The CAIR FIPs for all States in the CAIR region were promulgated on April 28, 2006 and subsequently revised on December 13, 2006.

CAIR requires States to reduce emissions of $SO_2$ and nitrogen oxides ($NO_X$) that significantly contribute to, and interfere with maintenance of, the national ambient air quality standards for fine particulates and/or ozone in any downwind state. CAIR establishes State budgets for $SO_2$ and $NO_X$ and requires States to submit SIP revisions that implement these budgets in States that EPA concluded did contribute to nonattainment in downwind states. States have the flexibility to choose which control measures to adopt to achieve the budgets, including participating in the EPA-administered cap-and-trade programs. In the SIP revision that EPA is proposing to approve, Louisiana would meet CAIR $SO_2$ requirements by participating in the EPA-administered cap-and-trade program addressing $SO_2$ emissions.

The intended effect of this action is to reduce $SO_2$ emissions from the State of Louisiana that are contributing to nonattainment of the $PM_{2.5}$ National Ambient Air Quality Standard (NAAQS or standard) in downwind states. This action is being taken under section 110 of the Federal Clean Air Act (the Act or CAA).

**DATES:** Comments must be received on or before August 20, 2007.

**ADDRESSES:** Comments may be mailed to Mr. Jeff Robinson, Chief, Air Permits Section (6PD–R), Environmental Protection Agency, 1445 Ross Avenue, Suite 1200, Dallas, Texas 75202–2733. Comments may also be submitted electronically or through hand delivery/courier by following the detailed instructions in the ADDRESSES section of the direct final rule located in the rules section of this **Federal Register**.

**FOR FURTHER INFORMATION CONTACT:** If you have questions concerning today's proposal, please contact Ms. Adina Wiley (6PD–R), Air Permits Section, Environmental Protection Agency, Region 6, 1445 Ross Avenue (6PD–R), Suite 1200, Dallas, TX 75202–2733. The telephone number is (214) 665–2115. Ms. Wiley can also be reached via electronic mail at *wiley.adina@epa.gov.*

**SUPPLEMENTARY INFORMATION:** In the final rules section of this **Federal Register**, EPA is approving the State's SIP submittal as a direct final rule without prior proposal because the Agency views this as a noncontroversial submittal and anticipates no relevant adverse comments. A detailed rationale for the approval is set forth in the direct final rule. If no relevant adverse comments are received in response to this action, no further activity is contemplated. If EPA receives relevant 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 the 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: July 11, 2007.

**Lawrence Starfield,**

*Acting Regional Administrator, EPA Region 6.*

[FR Doc. E7–14067 Filed 7–19–07; 8:45 am]

**BILLING CODE 6560–50–P**

---

## ENVIRONMENTAL PROTECTION AGENCY

### 40 CFR Part 52

**[Region II Docket No. EPA–R02–OAR–2007–0368, FRL–8442–3]**

### Approval and Promulgation of Implementation Plans; New York Emission Statement Program

**AGENCY:** Environmental Protection Agency.

**ACTION:** Proposed rule.

**SUMMARY:** The Environmental Protection Agency (EPA) is proposing to approve the State Implementation Plan (SIP) revision submitted by the State of New York on July 7, 2006 for the purpose of enhancing an existing Emission Statement Program for stationary sources in New York. The SIP revision consists of amendments to Title 6 of the New York Codes Rules and Regulations, Chapter III, Part 202, Subpart 202–2, Emission Statements. The SIP revision was submitted by New York to satisfy the ozone nonattainment provisions of the Clean Air Act. These provisions require states in which all or part of any ozone nonattainment area is located to submit a revision to its SIP which requires owner/operators of stationary sources of volatile organic compounds (VOC) and oxides of nitrogen ($NO_X$) to provide the State with a statement, at least annually, of the source's actual emissions of VOC and $NO_X$.

The Emission Statement SIP revision EPA proposes to approve enhances the reporting requirements for VOC and $NO_X$ and expands the reporting requirement, based on specified emission thresholds, to include carbon monoxide (CO), sulfur dioxides ($SO_2$), particulate matter measuring 2.5 microns or less ($PM_{2.5}$), particulate matter measuring 10 microns or less ($PM_{10}$), ammonia ($NH_3$), lead (Pb) and lead compounds and hazardous air pollutants (HAPS). The intended effect is to obtain improved emissions related data from facilities located in New York, allowing New York to more effectively plan for and attain the national ambient air quality standards (NAAQS). The Emission Statement rule also improves EPA's and the public's access to facility-specific emission related data.

**DATES:** Comments must be received on or before August 20, 2007.

**ADDRESSES:** Submit your comments, identified by Docket ID No. EPA–R02–OAR–2006–0368, by one of the following methods:

*www.regulations.gov:* Follow the on-line instructions for submitting comments.

*E-mail: Werner.Raymond@epa.gov*

*Fax:* 212–637–3901

*Mail:* Raymond Werner, Chief, Air Programs Branch, Environmental Protection Agency, Region 2 Office, 290 Broadway, 25th Floor, New York, New York 10007–1866.

*Hand Delivery:* Raymond Werner, Chief, Air Programs Branch, Environmental Protection Agency, Region 2 Office, 290 Broadway, 25th Floor, New York, New York 10007–1866. Such deliveries are only accepted during the Regional Office's normal hours of operation. The Regional Office's official hours of business are Monday through Friday, 8:30 to 4:30 excluding Federal holidays.

*Instructions:* Direct your comments to Docket ID No. EPA–R02–OAR–2006–0368. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *www.regulations.gov* or e-mail. The *www.regulations.gov* Web site is an ''anonymous access'' system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through *www.regulations.gov* your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses. For additional information about EPA's public docket visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm.*

**FOR FURTHER INFORMATION CONTACT:** Raymond K. Forde, Air Programs Branch, Environmental Protection Agency, 290 Broadway, 25th Floor, New York, New York 10007–1866, (212) 637–3716, *forde.raymond@epa.gov.*

Copies of the State submittals are available at the following addresses for inspection during normal business hours:

Environmental Protection Agency, Region 2 Office, Air Programs Branch, 290 Broadway, 25th Floor, New York, New York 10007–1866.

New York State Department of Environmental Conservation, Division of Air Resources, 625 Broadway, 2nd Floor, Albany, New York 12233.

**SUPPLEMENTARY INFORMATION:** The following table of contents describes the format for this section:

## I. What Is the Nature of EPA's Action?

EPA is proposing to approve the State Implementation Plan (SIP) revision submitted by the State of New York on July 7, 2006 for the purpose of enhancing an existing Emission Statement program for stationary sources in New York. The SIP revision consists of amendments to Title 6 of the New York Codes Rules and Regulations (NYCRR), Chapter III, Part 202, Subpart 202–2, Emission Statements (Emission Statement rule).

The SIP revision was submitted by New York to satisfy the ozone nonattainment provisions of the Clean Air Act. These provisions require states in which all or part of any ozone non-attainment area is located to submit a revision to its SIP which requires owner/operators of stationary sources of volatile organic compounds (VOC) and oxides of nitrogen ($NO_X$) to provide the State with a statement, at least annually, of the source's actual emissions of VOC and $NO_X$.

## II. What Are the Emissions Reporting Required by the Clean Air Act and How Does New York's Regulation Address Them?

*Emission Statements (Annual Reporting of VOC and $NO_X$)*

The air quality planning and SIP requirements for ozone nonattainment and transport areas are established in Subparts 1 and 2 of Part D of Title I of the Clean Air Act, as amended in 1990 (the Act). EPA has published a ''General Preamble'' and ''Appendices to the General Preamble'' (see 57 FR 13498 (April 16, 1992), and 57 FR 18070 (April 28, 1992)) describing how EPA intends to review SIPs submitted under Title I of the Act.

EPA has also issued a draft guidance document, entitled ''Guidance on the Implementation of an Emission Statement Program'' (Emission Statement Guidance), dated July 1992, which describes the minimum requirements for approvable emission statement programs.

Section 182(a)(3)(B)(i) of the Act requires states in which all or part of any ozone non-attainment area is located to submit SIP revisions to EPA by November 15, 1992, which require owner/operators of stationary sources of VOC and $NO_X$ to provide the state with a statement, at least annually, of the source's actual emissions of VOC and $NO_X$. Sources were to submit the first emission statements to their respective states by November 15, 1993. Pursuant to the Emission Statement Guidance, if the source emits either VOC or $NO_X$ at or above levels for which the State Emission Statement rule requires reporting, the other pollutant (VOC or $NO_X$) from the same facility should be included in the emission statement, even if the pollutant is emitted at levels below the minimum reporting level.

Section 182(a)(3)(B)(ii) of the Act allows states to waive, with EPA approval, the requirement for an emission statement for classes or categories of sources located in nonattainment areas, which emit less than 25 tons per year of actual plant-wide VOC and $NO_X$, provided the class or category is included in the base year and periodic inventories and emissions are calculated using emission factors established by EPA (such as those found in EPA publication AP–42) or other methods acceptable to EPA.

EPA has determined that New York's Emission Statement rule, which requires facilities to report information for the criteria pollutants and the associated precursors listed above, satisfies the federal emission statement reporting requirements for major sources.

*Consolidated Emission Reporting Rule (Annual Reporting for All Criteria Pollutants)*

In order to consolidate reporting requirements by the states to EPA, on June 10, 2002 (See 67 FR 39602), EPA published the final Consolidated Emissions Reporting Rule (CERR). The purpose of the CERR is to simplify the states' annual reporting, to EPA, of criteria pollutants (VOC, $NO_X$, $SO_2$, $PM_{10}$, $PM_{2.5}$, CO, Pb) for which National Ambient Air Quality Standards (NAAQS) have been established, and annual reporting of $NH_3$, a precursor pollutant. The CERR also provides options for data collection and exchange, and unified reporting dates for various categories of criteria pollutant emission inventories. The CERR requires states to report annually to EPA on emissions of $NO_X$, CO, VOC, Pb, $SO_2$ and $PM_{10}$, for industrial point sources, based on specific emission thresholds. The CERR emissions reports for calendar year 2001 were due on June 1, 2003, and subsequent reports were due every year thereafter (i.e., calendar year 2002 emission inventory due June 1, 2004, etc.). Reporting of $PM_{2.5}$ and NH3 from point sources was not required until June 2004, for emissions that occurred during calendar year 2002.

EPA has determined that New York's Emission Statement rule, which requires facilities to report information for the criteria pollutants and the associated precursors mentioned above, satisfies the federal CERR requirements for major sources.

*Hazardous Air Pollutants (Periodic Reporting of Hazardous Air Pollutants)*

In addition to the emission inventory provisions related to the criteria pollutants, EPA has requested that the states report on hazardous air pollutants (HAPs) emissions from anthropogenic sources, for the National Toxics Inventory (NTI). The NTI is a comprehensive national inventory of HAP emissions from stationary and mobile sources that is revised by EPA every three years.

The NTI contains emission estimates for point sources, non-point sources and mobile sources. Point sources include major and non-point source categories as defined in Section 112 of the Clean Air Act. Non-point source categories include area source categories. Individual emission estimates are developed for point sources, while aggregate emission estimates at the county level are developed and recorded for non-point stationary and mobile sources. The NTI also identifies facilities and non-point source categories that are associated with MACT categories.

*Need for NTI Inventory*

Title V of the Act requires the Administrator to perform an oversight role with respect to state issued permits, including permits issued to major sources of HAP emissions. In order to determine whether that program is being appropriately and lawfully administered by the states with respect to major HAP sources, a HAP emission inventory is necessary. States are developing programs to regulate HAPs, and Title V of the Act requires state Title V programs to include permits for all HAP sources emitting major quantities of HAPs (10 tons of one HAP or 25 tons of multiple HAPs per year). Thus, EPA believes including HAPs in the point source inventory is appropriate and necessary.

Section 112(n)(1)(A) of the Act requires EPA to report to Congress on the hazards to public health reasonably anticipated to occur as a result of emissions from electric utility steam generating units. Section 112(n)(1)(B) requires EPA to provide a report to Congress that considers the rate and mass of HAP emissions and the health and environmental effects of these emissions. Section 112(c)(6) requires a list of categories and subcategories of HAP sources subject to standards that account for not less than 90 percent of the aggregate emission of each pollutant. Although these new requirements do not include specific provisions requiring the compilation of HAP emissions inventories, they do introduce the need for such inventories in order to carry out the mandate of the statute.

In addition, Section 112(k)(3) of the Act mandates that EPA develop a strategy to control emissions of HAPs from area sources in urban areas, and that the strategy achieves a reduction in the incidence of cancer attributable to exposure to HAPs emitted by stationary sources of not less than 75 percent, considering control of emissions from all stationary sources, as well as achieves a substantial reduction in public health risks posed by HAPs from area sources. These mandated risk reductions are to be achieved by taking into account all emission control measures implemented by the Administrator or by the states under this or any other laws. A reliable HAP emission inventory covering all stationary sources of HAPs, including point and area sources, is important in implementing the mandated strategy and demonstrating that the strategy achieves the mandated risk reductions. It would be virtually impossible for EPA to identify and estimate HAP-specific emission reductions from all the Federal and state rules that might result in HAP emission reductions. Therefore, EPA has determined that development of the strategy and assessment of progress in achieving the strategic goals requires the development and periodic update of a HAP emission inventory. As presented in the July 19, 1999 **Federal Register** notice on the National Air Toxics Program: The Integrated Urban Strategy (64 FR 38706), a designed approach has been developed that depends upon a reliable and periodically updated HAP emission inventory as a critical element in the assessments that support the development and evaluation of our urban strategy.

EPA has determined that New York's Emission Statement rule, which requires facilities to report information for the HAPs, assists the State in satisfying the HAPs reporting requirements for major sources.

## III. What Was Included in New York's Submittal?

*New York's Submittal*

On July 7, 2006, New York submitted a SIP revision for ozone which included an adopted Emission Statement rule. The regulation amends Title 6 of the NYCRR, Subpart 202–2, Emission Statements, which was originally adopted on July 13, 2004. On April 12, 2005, the New York State Department of Environmental Conservation (NYSDEC) adopted these amendments, which became effective on May 29, 2005.

*EPA's Findings*

EPA has determined that an approvable Emission Statement program must have several components. Specifically, a state must submit its program as a revision to its SIP, and the state's emission statement program must meet the minimum requirements for reporting as outlined in EPA's Emission Statement Guidance. The program must include, at a minimum, provisions specifying source applicability, definitions, compliance, and specific source reporting requirements.

EPA's technical review of New York's Emission Statement program is contained in a technical support document (emission statement enforceability checklist) available in the docket at *www.regulations.gov* or by contacting the person identified earlier in this notice.

*Applicability*

In ozone nonattainment areas within the State, facilities which emit or have the potential to emit VOC and/or $NO_X$ in amounts of 25 tons per year or more must submit, to the State, an annual emission statement. In attainment areas located within the State, which is part of the ozone transport region (OTR) established by operation of law under Section 184 of the Act, New York's Emission Statement rule requires facilities actually emitting or having the potential to emit 50 tons per year or more of VOC or 100 tons per year or more of $NO_X$ to submit, to the State, an annual emission statement.

For Title V affected facilities located in ozone nonattainment areas within the State, which emit or have the potential to emit VOC and/or $NO_X$ in amounts of 25 tons per year or more, the Emission Statement rule includes provisions that require such facilities to submit annual emission statements for VOC, $NO_X$, CO, $SO_2$, Pb or lead compounds, $PM_{10}$, $PM_{2.5}$, $NH_3$ and HAPs.

For Title V affected facilities located in OTR attainment areas within the State, which emit or have the potential to emit 50 tons per year or more of VOC or 100 tons per year or more of $NO_X$, the Emission Statement rule includes provisions that require such facilities to submit annual emission statements for VOC, $NO_X$, CO, $SO_2$, Pb or lead compounds, $PM_{10}$, $PM_{2.5}$, $NH_3$, and HAPs.

New York's regulation includes provisions that require Title V facilities within the State, which emit or have the potential to emit 100 tons per year or more of any criteria pollutant, to submit annual emission statements for VOC, $NO_X$, CO, $SO_2$, Pb or lead compounds, $PM_{10}$, $PM_{2.5}$, $NH_3$, and HAPs.

New York's regulation includes provisions that require Title V facilities which emit or have the potential to emit 10 tons per year or more of an individual HAP or 25 tons per year or more of multiple HAPs, to submit annual emission statements for VOC, $NO_X$, CO, $SO_2$, Pb or lead compounds, $PM_{10}$, $PM_{2.5}$, $NH_3$, and HAPs.

EPA has determined that New York's Emission Statement rule contains applicability provisions that are consistent with the minimum requirements for state emission statement SIPs. In addition, the Emission Statement rule assists the State in satisfying the annual reporting requirements for the federal CERR, and in developing a HAPs emission inventory for use in National Air Toxics Assessment.

*Definitions*

The key definitions that New York included in its Emission Statement regulation are consistent with the EPA guidance.

*Compliance*

Under Section 110 of the Act, all SIP requirements must be enforceable by the State and EPA. Article 71 of the New York Environmental Conservation Law provides the State with the authority to, among other things, issue compliance orders with appropriate penalties and injunctive relief for sources failing to comply with the Emission Statement rule. EPA has determined that New York has an adequate program in place to ensure that the Emission Statement rule is enforceable.

*Reporting Requirements*

In accordance with CAA Section 182(a)(3)(B) and the Emission Statement Guidance, the Emission Statement rule requires facilities to supply the necessary source-specific data elements in annual emission statements. The survey forms that New York provides to facilities for use in reporting emission data are not EPA forms, but still require the necessary data.

*Confidential Business Information*

On December 29, 2006, EPA sent a letter to NYSDEC, regarding New York's Emission Statement rule, requesting clarification on the rule's confidential business information (CBI) provision, as it relates to air pollutant emissions data collected under the emission statement program. The letter requested that NYSDEC clarify one issue related to the rule; the trade secret provision found in

Title 6 of the NYCRR, Chapter III, Part 202, Subpart 202–2.4(i). Specifically, EPA requested that NYSDEC supplement the July 7, 2006 SIP submittal with a letter that confirms the trade secret provision will not restrict: (1) The public's access to facility-related ''emission data'' that is contained in emission statements, (2) EPA's access to all information contained in emission statements submitted to New York, including any emissions related information claimed and/or designated as trade secret or as confidential business information, and (3) that confirms NYSDEC interprets 6 NYCRR Subpart 202–2.4(i), coupled with 6 NYCRR Subpart 200.2, Safeguarding Information, to require the submission to EPA and release to the public of all information that is considered to be emissions data, consistent with the applicable state and federal laws on public disclosure, including the Clean Air Act and its implementing regulations.

On April 11, 2007, NYSDEC sent a letter to EPA in response. EPA has reviewed the letter and has determined that NYSDEC has adequately addressed EPA's concerns.

### IV. What Is EPA's Conclusion?

EPA has concluded that the New York Emission Statement rule contains the necessary applicability, compliance, enforcement and reporting requirements for an approvable emission statement program. EPA is proposing to approve 6 NYCRR, Chapter III, Part 202, Subpart 202–2, Emission Statements, as part of New York's SIP.

### V. Statutory and Executive Order Reviews

Under Executive Order 12866 (58 FR 51735, October 4, 1993), this proposed 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 proposed action merely proposes to approve state law as meeting Federal requirements and imposes no additional requirements beyond those imposed by state law. Accordingly, the Administrator certifies that this proposed 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 proposes to approve 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 proposed 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 proposes to approve a state rule implementing a Federal standard, and does not alter the relationship or the distribution of power and responsibilities established in the Clean Air Act. This proposed rule also is not subject to Executive Order 13045 ''Protection of Children from Environmental Health Risks and Safety Risks'' (62 FR 19885, April 23, 1997), because it is not economically significant.

In reviewing SIP 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 SIP submission for failure to use VCS. It would thus be inconsistent with applicable law for EPA, when it reviews a SIP submission, to use VCS in place of a SIP 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 proposed 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.*).

### List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Carbon monoxide, Lead, Nitrogen dioxide, Ozone, Particulate matter, Reporting and recordkeeping requirements, Sulfur oxides, Volatile organic compounds.

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

Dated: July 8, 2007.

**Alan J. Steinberg,**

*Regional Administrator, Region 2.*

[FR Doc. E7–14061 Filed 7–19–07; 8:45 am]

**BILLING CODE 6560–50–P**

## DEPARTMENT OF HEALTH AND HUMAN SERVICES

## Centers for Medicare & Medicaid Services

## 42 CFR Part 455

**[CMS–2264–P]**

**RIN 0938–AO88**

## Medicaid Integrity Program; Limitation on Contractor Liability

**AGENCY:** Centers for Medicare & Medicaid Services (CMS), HHS.

**ACTION:** Proposed rule.

**SUMMARY:** Section 6034 of the Deficit Reduction Act of 2005 established the Medicaid Integrity Program to promote the integrity of the Medicaid program by authorizing the Centers for Medicare and Medicaid Services (CMS) to enter into contracts with contractors that will review the actions of individuals or entities furnishing items or services (whether fee-for-service, risk, or other basis) for which payment may be made under an approved State plan and/or any waiver of the plan approved under section 1115 of the Social Security Act; audit claims for payment of items or services furnished, or administrative services furnished, under a State plan; identify overpayments of individuals or entities receiving Federal funds; and educate providers of services, managed care entities, beneficiaries, and other individuals with respect to payment integrity and quality of care. This proposed rule would set forth limitations on a contractor's liability while performing these services under the Medicaid Integrity Program.

This proposed rule would provide for limitation of a contractor's liability for actions taken to carry out a contract under the Medicaid Integrity Program. The proposed rule would, to the extent possible, employ the same or comparable standards and other substantive and procedural provisions as are contained in section 1157 (Limitation on Liability) of the Social Security Act.

**DATES:** To be assured consideration, comments must be received at one of the addresses provided below, no later than 5 p.m. on August 20, 2007.

**ADDRESSES:** In commenting, please refer to file code CMS–2264–P. Because of staff and resource limitations, we cannot accept comments by facsimile (Fax) transmission.

You may submit comments in one of four ways (no duplicates, please):

1. *Electronically*. You may submit electronic comments on specific issues in this regulation to *http://www.cms.hhs.gov/eRulemaking*. Click on the link ''Submit electronic comments on CMS regulations with an open comment period.'' (Attachments should be in Microsoft Word, WordPerfect, or Excel; however, we prefer Microsoft Word.)

2. *By regular mail*. You may mail written comments (one original and two copies) to the following address Only: Centers for Medicare & Medicaid Services, Department of Health and Human Services, Attention: CMS–2264–P, P.O. Box 8014, Baltimore, MD 21244–8014.

Please allow sufficient time for mailed comments to be received before the close of the comment period.

3. *By express or overnight mail*. You may send written comments (one original and two copies) to the following address Only: Centers for Medicare & Medicaid Services, Department of Health and Human Services, Attention: CMS–2264–P, Mail Stop C4–26–05, 7500 Security Boulevard, Baltimore, MD 21244–1850.

4. *By hand or courier*. If you prefer, you may deliver (by hand or courier) your written comments (one original and two copies) before the close of the comment period to one of the following addresses. If you intend to deliver your comments to the Baltimore address, please call telephone number (410) 786–8148 in advance to schedule your arrival with one of our staff members. Room 445–G, Hubert H. Humphrey Building, 200 Independence Avenue, SW., Washington, DC 20201; or 7500 Security Boulevard, Baltimore, MD 21244–1850.

(Because access to the interior of the HHH Building is not readily available to persons without Federal Government identification, commenters are encouraged to leave their comments in the CMS drop slots located in the main lobby of the building. A stamp-in clock is available for persons wishing to retain a proof of filing by stamping in and retaining an extra copy of the comments being filed.)

Comments mailed to the addresses indicated as appropriate for hand or courier delivery may be delayed and received after the comment period.

For information on viewing public comments, see the beginning of the **SUPPLEMENTARY INFORMATION** section.

**FOR FURTHER INFORMATION CONTACT:** Barbara Rufo, 410–786–5589 or Crystal High, 410–786–8366.

**SUPPLEMENTARY INFORMATION:**

*Submitting Comments:* We welcome comments from the public on all issues set forth in this rule to assist us in fully considering issues and developing policies. You can assist us by referencing the file code CMS–2064–P and the specific ''issue identifier'' that precedes the section on which you choose to comment.

*Inspection of Public Comments:* All comments received before the close of the comment period are available for viewing by the public, including any personally identifiable or confidential business information that is included in a comment. We post all comments received before the close of the comment period on the following Web site as soon as possible after they have been received: *http://www.cms.hhs.gov/eRulemaking*. Click on the link ''Electronic Comments on CMS Regulations'' on that Web site to view public comments.

Comments received timely will also be available for public inspection as they are received, generally beginning approximately 3 weeks after publication of a document, at the headquarters of the Centers for Medicare & Medicaid Services, 7500 Security Boulevard, Baltimore, Maryland 21244, Monday through Friday of each week from 8:30 a.m. to 4 p.m. To schedule an appointment to view public comments, phone 1–800–743–3951.

## I. Background

### *A. Current Law*

States and the Federal Government share in the responsibility for safeguarding Medicaid program integrity. States must comply with Federal requirements designed to ensure that Medicaid funds are properly spent (or recovered, when necessary). The Centers for Medicare and Medicaid Services (CMS) is the primary Federal agency responsible for providing oversight of States' activities and facilitating their program integrity efforts.

### *B. Medicaid Integrity Program*

Section 6034 of the Deficit Reduction Act (DRA) of 2005 (Pub. L. 109–171, enacted on February 8, 2006) established the Medicaid Integrity Program (the Program), within CMS to combat Medicaid fraud and abuse. For the first time, the Program authorizes the Federal government to directly identify, recover, and prevent inappropriate Medicaid payments. It would also support the efforts of the State Medicaid agencies through a combination of oversight and technical assistance.

Although individual States work to ensure the integrity of their respective Medicaid programs, the Program represents our first comprehensive national strategy to detect and prevent Medicaid fraud and abuse. The Program would provide CMS with the ability to more directly ensure the accuracy of Medicaid payments and to deter those who would exploit the program.

Section 6034 of the DRA amended title XIX of the Social Security Act (the Act), (42 U.S.C. 1396 *et seq.*) by redesignating the old section 1936 as section 1937; and inserting the new section 1936 ''Medicaid Integrity Program.''

The new section 1936 of the Act states that the Secretary promote the integrity of the Medicaid program by entering into contracts with eligible entities to carry out the following activities:

1. Review of the actions of individuals or entities furnishing items or services (whether on a fee-for-service, risk or other basis) for which payment may be made under a State plan approved under title XIX (or under any waiver of this plan approved under section 1115 of the Act) to determine whether fraud, waste, and/or abuse has occurred, or is likely to occur, or whether these actions have any potential for resulting in an expenditure of funds under title XIX in a manner that is not intended under the provisions of title XIX.

2. Audit of claims for payment for items or services furnished, or administrative services rendered, under a State plan under title XIX, including cost reports, consulting contracts; and risk contracts under section 1903(m) of title XIX.

3. Identification of overpayments to individuals or entities receiving Federal funds under title XIX.

4. Education of providers of services, managed care entities, beneficiaries, and other individuals with respect to payment integrity and quality of care.

Section 6034 of the DRA also mandated that the Secretary will by regulation provide for the limitation of a contractor's liability for actions taken to carry out a contract under the Medicaid Integrity Program.

## II. Provisions of the Proposed Rule

[If you wish to comment on issues in this section, please include the caption ''Provisions of the Proposed Rule'' at the beginning of your comments.]

*Limitations on Contractor Liability*

Contractors that perform activities under the Medicaid Integrity Program (the Program), would be reviewing activities of providers and others seeking Medicaid payment for providing services to Medicaid beneficiaries. In an effort to reduce or eliminate the Program contractor's exposure to possible legal action from entities it reviews, section 6034 of the DRA requires that we, by regulation, limit the Program contractor's liability for actions taken in carrying out its contract. We must establish, to the extent we find appropriate, standards and other substantive and procedural provisions that are the same as, or comparable to, those contained in section 1157 of the Act.

Section 1157 of the Act states that any organization having a contract with the Secretary, its employees, fiduciaries, and anyone who furnishes professional services to these organizations are protected from civil and criminal liability in performing their duties under the Act or their contract, provided these duties are performed with due care.

Following the mandate of section 6034 of the DRA, this proposed rule, in § 455.1, Basis and scope, would add a new paragraph (c) stating that subpart C implements section 1936 of the Act. Section 1936 of the Act establishes the Medicaid Integrity Program under which the Secretary will promote the integrity of the program by entering into contracts with eligible entities to carry out the activities under subpart C. In addition, new subpart C, § 455.200(a), would specify the statutory basis of proposed new subpart C, which would implement section 1936 of the Act, which states that the Secretary will promote the integrity of the Medicaid program by entering into contracts with eligible entities to carry out the activities under subpart C. Section 455.200(b) would provide the scope for the limitation on a contractor's liability to carry out a contract under the Medicaid Integrity Program as proposed under new § 455.202. Section 455.202(a) would protect Program contractors from liability in the performance of their contracts provided they carry out their contractual duties with due care.

In accordance with section 6034 of the DRA, we propose to employ the same standards for payment of legal expenses as are contained in section 1157(d) of the Act. Therefore, § 455.202(b) would provide that we would make payment to Program contractors, their members, employees, and anyone who provides legal counsel or services to them, for expenses incurred in the defense of any legal action related to the performance of the Program contract. We also propose that any and all payment(s) and the amount of each payment(s) if any, would be determined exclusively by us, and conditioned upon (1) the reasonableness of the expense(s); (2) the amount of government funds available for payment(s); and (3) whether the payment(s) is (are) allowable under the terms of the contract.

In drafting § 455.202, we considered employing a standard for the limitation of liability other than the due care standard. We considered whether it would be appropriate to provide that a contractor would not be civilly liable by reason of the performance of any duty, function, or activity under its contract provided the contractor was not grossly negligent in that performance. However, section 6034 of the DRA requires that we employ the same or comparable standards and provisions as are contained in section 1157 of the Act. This approach is consistent with a similar approach taken in the Medicare Integrity Program (see 70 FR 35204), which has virtually identical statutory limitations on contractor liability language. Therefore, we do not believe that it would be appropriate to expand the scope of immunity to a standard of gross negligence, as it would not be a comparable standard to that set forth in section 1157(b) of the Act.

## III. Collection of Information Requirements

This document does not impose information collection and recordkeeping requirements. Consequently, it need not be reviewed by the Office of Management and Budget under the authority of the Paperwork Reduction Act of 1995.

## IV. Response to Comments

Because of the large number of public comments we normally receive on **Federal Register** documents, we are not able to acknowledge or respond to them individually. We will consider all comments we receive by the date and time specified in the **DATES** section of this preamble, and, when we proceed with a subsequent document, we will respond to the comments in the preamble to that document.

## V. Regulatory Impact Statement

[If you wish to comment on issues in this section, please include the caption "Regulatory Impact Statement" at the beginning of your comments.]

We have examined the impact of this rule as required by Executive Order 12866 (September 1993, Regulatory Planning and Review), the Regulatory Flexibility Act (RFA) (September 19, 1980, Pub. L. 96–354), section 1102(b) of the Social Security Act, the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4), and Executive Order 13132.

Executive Order 12866 directs agencies to assess all costs and benefits of available regulatory alternatives and, if regulation is necessary, to select regulatory approaches that maximize net benefits (including potential economic, environmental, public health and safety effects, distributive impacts, and equity). A regulatory impact analysis (RIA) must be prepared for major rules with economically significant effects ($100 million or more in any 1 year). This rule would not reach the economic threshold and thus is not considered a major rule.

The RFA requires agencies to analyze options for regulatory relief of small businesses. For purposes of the RFA, small entities include small businesses, nonprofit organizations, and small governmental jurisdictions. Most hospitals and most other providers and suppliers are small entities, either by nonprofit status or by having revenues of $6 million to $29 million in any 1 year. Individuals and States are not included in the definition of a small entity. We are not preparing an analysis for the RFA because we have determined that this rule would not have a significant economic impact on a substantial number of small entities.

In addition, section 1102(b) of the Act requires us to prepare a regulatory impact analysis if a rule may have a significant impact on the operations of a substantial number of small rural hospitals. This analysis must conform to the provisions of section 603 of the RFA. For purposes of section 1102(b) of the Act, we define a small rural hospital as a hospital that is located outside of a Core-Based Statistical Area and has fewer than 100 beds. We are not preparing an analysis for section 1102(b) of the Act because we have determined that this rule would not have a significant impact on the operations of a substantial number of small rural hospitals.

Section 202 of the Unfunded Mandates Reform Act of 1995 also requires that agencies assess anticipated costs and benefits before issuing any rule whose mandates require spending in any 1 year of $100 million in 1995 dollars, updated annually for inflation. That threshold level is currently approximately $120 million. This rule would have no consequential effect on State, local, or tribal governments or on the private sector.

Executive Order 13132 establishes certain requirements that an agency must meet when it promulgates a proposed rule (and subsequent final rule) that imposes substantial direct requirement costs on State and local governments, preempts State law, or otherwise has Federalism implications. Since this regulation would not impose any costs on State or local governments, the requirements of E.O. 13132 are not applicable.

In accordance with the provisions of Executive Order 12866, this regulation was reviewed by the Office of Management and Budget.

**List of Subjects 42 CFR in Part 455**

Fraud, Grant programs—health, Health facilities, Health professions, Investigations, Medicaid, Reporting and recordkeeping requirements.

For the reasons set forth in the preamble, the Centers for Medicare & Medicaid Services would amend 42 CFR chapter IV as set forth below:

## PART 455—PROGRAM INTEGRITY; MEDICAID

1. The authority citation for part 455 continues to read as follows:

**Authority:** Sec. 1102 of the Social Security Act (42 U.S.C. 1302).

2. In § 455.1, add new paragraph (c) to read as follows:

**§ 455.1 Basis and scope.**

* * * * *

(c) Subpart C implements section 1936 of the Act. It establishes the Medicaid Integrity Program under which the Secretary will promote the integrity of the program by entering into contracts with eligible entities to carry out the activities of subpart C.

3. New subpart C, consisting of § 455.200 and § 455.202, is added to part 455 to read as follows:

**Subpart C—Medicaid Integrity Program**

Sec.
455.200 Basis and scope.
455.202 Limitation on contractor liability.

## Subpart C—Medicaid Integrity Program

**§ 455.200 Basis and scope.**

(a) *Statutory basis.* This subpart implements section 1936 of the Act that establishes the Medicaid Integrity Program under which the Secretary will promote the integrity of the program by entering into contracts with eligible entities to carry out the activities under this subpart C.

(b) *Scope.* This subpart provides for the limitation on a contractor's liability to carry out a contract under the Medicaid Integrity Program.

**§ 455.202 Limitation on contractor liability.**

(a) A program contractor, a person, or an entity employed by, or having a fiduciary relationship with, or who furnishes professional services to a program contractor will not be held to have violated any criminal law and will not be held liable in any civil action, under any law of the United States or of any State (or political subdivision thereof), by reason of the performance of any duty, function, or activity required or authorized under this subpart or under a valid contract entered into under this subpart, provided due care was exercised in that performance and the contractor has a contract with CMS under this subpart.

(b) CMS pays a contractor, a person, or an entity described in paragraph (a) of this section, or anyone who furnishes legal counsel or services to a contractor or person, a sum equal to the reasonable amount of the expenses, as determined by CMS, incurred in connection with the defense of a suit, action, or proceeding, if the following conditions are met:

(1) The suit, action, or proceeding was brought against the contractor, person or entity by a third party and relates to the contractor's, person's or entity's performance of any duty, function, or activity under a contract entered into with CMS under this subpart.

(2) The funds are available.

(3) The expenses are otherwise allowable under the terms of the contract.

(Catalog of Federal Domestic Assistance Program No. 93.778, Medical Assistance Program)

Dated: March 15, 2007.

**Leslie V. Norwalk,**

*Acting Administrator, Centers for Medicare & Medicaid Services.*

Approved: April 20, 2007.

**Michael O. Leavitt,**

*Secretary.*

[FR Doc. E7–14115 Filed 7–19–07; 8:45 am]

BILLING CODE 4120–01–P

## DEPARTMENT OF COMMERCE

### National Oceanic and Atmospheric Administration

### 50 CFR Part 600

**[Docket No. 070607179–7312–01]**

**RIN 0648–AV66**

### Fishing Capacity Reduction Program for the Longline Catcher Processor Subsector of the Bering Sea and Aleutian Islands Non-Pollock Groundfish Fishery, Industry Fee System

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

**ACTION:** Proposed rule; request for comments.

**SUMMARY:** NMFS proposes regulations to implement an industry fee system for repaying a $35 million Federal loan financing a fishing capacity reduction program in the longline catcher processor subsector of the Bering Sea and Aleutian Islands (BSAI) non-pollock groundfish fishery. This action's intent is to implement a fee collection system to ensure repayment of the loan.

**DATES:** Comments on this proposed rule must be received by August 20, 2007.

**ADDRESSES:** Comments may be submitted by any of the following methods:

- E-mail: *0648–AV66.FeeSystem@noaa.gov*. Include in the subject line the following identifier: ''Longline catcher processor buyback fee system proposed rule.'' E-mail comments, with or without attachments, are limited to 5 megabytes;
- Federal e-Rulemaking Portal: *http://www.regulations.gov*;
- Mail to: Leo Erwin, Chief, Financial Services Division, NMFS–MB5, 1315 East-West Highway, Silver Spring, MD 20910; or
- Fax to 301–713–1306.

Comments involving the burden-hour estimates or other aspects of the collection-of-information requirements contained in this proposed rule should be submitted in writing to Leo Erwin, at the above address, and to David Rostker, Office of Management and Budget (OMB), by email at *David_Rostker@omb.eop.gov* or by fax to 202 395 7285.

Copies of the Environmental Assessment/Regulatory Impact Review/Final Regulatory Flexibility Analysis (EA/RIR/FRFA) prepared for the program may be obtained from Leo Erwin at the above address.

**FOR FURTHER INFORMATION CONTACT:** Leo Erwin at 301–713 2390.

**SUPPLEMENTARY INFORMATION:**

**Background**

Sections 312(b)-(e) of the Magnuson-Stevens Fishery Conservation and Management Act (16 U.S.C. 1861a(b) through (e)) generally authorized fishing capacity reduction programs. In particular, section 312(d) authorized industry fee systems for repaying the reduction loans which finance reduction program costs. Subpart L of 50 CFR part 600 is the framework rule generally implementing sections 312(b)–(e). Subpart M of 50 CFR part 600 contains specific fishery or program regulations.

Sections 1111 and 1112 of the Merchant Marine Act, 1936 (46 App. U.S.C. 1279f and 1279g) generally authorized reduction loans.

The FY 2005 Appropriations Act (Public Law 108–447, Section 219) authorized a fishing capacity reduction program for the longline catcher processor subsector of the BSAI non-pollock groundfish fishery (reduction fishery).

NMFS published the longline catcher processor subsector BSAI non-pollock reduction program's (reduction program) proposed implementation rule on August 11, 2006 (71 FR 46364) and its final rule on September 29, 2006 (71 FR 57696). Anyone interested in the reduction program's full implementation details should refer to these two documents. NMFS proposed and adopted the reduction program's implementation rule as § 600.1105 of subpart M of 50 CFR part 600.

The reduction program's objectives include promoting sustainable fishery management and maximum sustained reduction of fishing capacity from the reduction fishery at the least cost. This is a voluntary program in which, in return for reduction payments, selected offerors permanently relinquished their fishing licenses, surrendered the fishing histories upon which those licenses' issuance were based, and permanently withdrew vessels from fishing.

NMFS financed the reduction program's $35 million cost, which post-reduction BSAI non-pollock groundfish longline catcher processors repay over an anticipated 30-year term but fees will continue indefinitely for as long as necessary to fully repay the loan.

The fee amount, expressed in cents per pound rounded up to the next one-tenth of a cent, will be based upon the annual principal and interest due on the loan and could be up to 5 percent of longline catcher processor subsector BSAI Pacific cod landings. In the event that the total principal and interest due exceeds 5 percent of the ex-vessel Pacific cod revenues, an additional fee of one penny per pound will be assessed for pollock, arrowtooth flounder, Greenland turbot, skate, yellowfin sole and rock sole.

The Freezer Longline Conservation Cooperative (FLCC) received member offers and subsequently voted to accept four offers. The FLCC submitted a fishing capacity reduction plan (reduction plan) subsequently approved by NMFS. A referendum concerning the fees necessary for repayment of the $35 million loan followed the offer and acceptance process. Approval of the industry fee system required at least two-thirds of the votes cast in the referendum to be in favor before the reduction program could be implemented and payment tendered.

NMFS mailed ballots to 39 qualified referendum voters on March 21, 2007, after approving the reduction plan. The voting period opened on March 21, 2007, and closed on April 6, 2007. NMFS received 34 timely and valid votes. All of the votes approved the fees. This exceeded the two-thirds minimum required for industry fee system approval. Consequently, this referendum was successful and approved the industry fee system.

On April 26, 2007, NMFS published a **Federal Register** notice (72 FR 20836) advising the public that NMFS would, beginning on May 29, 2007, tender the reduction program's reduction payments to the four selected offerors. On May 29, 2007, NMFS required the selected offerors to permanently stop all fishing with the reduction vessels and permits. Subsequently, NMFS:

1. Disbursed $35,000,000 in reduction payments to the four selected offerors;
2. Revoked the relinquished reduction licenses;
3. Revoked each reduction vessel's fishing history;
4. Notified the National Vessel Documentation Center to revoke the reduction vessels' fishery trade endorsements and appropriately annotate the reduction vessel's document; and
5. Notified the U.S. Maritime Administration to prohibit the reduction vessel's transfer to foreign ownership or registry.

Selected offerors participating in the reduction program have received $35 million in exchange for relinquishing valid non-interim Federal License Limitation Program BSAI groundfish licenses endorsed for catcher processor fishing activity, catcher/processor, Pacific cod, and hook and line gear, as well as any present or future claims of eligibility for any fishing privilege based on such permit, and additionally, any future fishing privilege of the vessel named on the permit. Individual fishing quota shares are excluded from relinquishment.

**II. Proposed Regulations**

NMFS has completed the reduction program except for implementing the industry fee system which this action proposes to implement. The fee amount will be calculated on an annual basis as: the principal and interest payment amount due over the proceeding twelve months, divided by the reduction fishery portion of the BSAI Pacific cod initial total allowable catch (ITAC) allocation in metric tons multiplied by 2,205 to convert into pounds, provided that the fees should not exceed 5 percent of the average ex-vessel production value of the reduction fishery.

The terms defined in § 600.1105 of the reduction program's implementation rule and in § 600.1000 of the framework rule apply to this action.

The framework rule's § 600.1013 governs fee payment and collection in general, and this action applies the § 600.1013 provisions to the reduction program.

Under § 600.1013, the first ex-vessel buyers (fish buyers) of post-reduction fish (fee fish) subject to an industry fee system must withhold the fee from the trip proceeds which the fish buyers would otherwise have paid to the parties (fish sellers) who harvested and first sold the fee fish to the fish buyers. For the purpose of the fee collection, deposit, disbursement, and accounting requirements of this subpart, subsector members are deemed to be both the fish buyer and fish seller. In this case, all requirements and penalties of § 600.1013 of this subpart that are applicable to both a fish seller and a fish buyer shall equally apply to parties performing both functions.

The BSAI Pacific cod ITAC was chosen as the basis for fee calculation of the reduction program because Pacific cod is the only directed fishery with a total allowable catch set in advance of the fishing season. This methodology allows for a straightforward calculation of the fee due and simplifies future accounting. The fee will be assessed and collected on Pacific cod to the extent possible and if the amount is not sufficient to cover annual principal and interest due, additional fees will be assessed and collected. Fees will be assessed and collected on all harvested Pacific cod, including that used for bait or discarded. Although the fee could be up to 5 percent of the ex-vessel production value of all post-reduction longline catcher processor subsector non-pollock groundfish landings, the fee will be less than 5 percent if NMFS projects that a lesser rate can amortize the fishery's reduction loan over the reduction loan's 30-year term.

If the total principal and interest due exceeds five percent of the ex-vessel Pacific cod revenues, a penny per pound round weight fee will be calculated based on the latest available revenue records and NMFS conversion factors for pollock, arrowtooth flounder, Greenland turbot, skate, yellowfin sole and rock sole. Any additional fees will be limited to the amount necessary to amortize the remaining twelve months principal and interest in addition to the five percent fee assessed against Pacific cod. If collections exceed the total principal and interest needed to amortize the payment due, the principal balance of the loan will be reduced.

To verify that the fees collected do not exceed five percent of the reduction fishery revenues, the annual total of principal and interest due will be compared with the latest available annual reduction fishery revenues to ensure it is equal to or less than five percent of the total ex-vessel production revenues. In all likelihood this will be based on State of Alaska's Commercial Operator Annual Report produced annually in the March following the close of the previous season. If any of the components necessary to calculate the next year's fee are not available, or for any other reason NMFS believes the calculation must be postponed, the fee will remain at the previous year's amount until such time that new calculations are made and communicated to the post reduction fishery participants.

The framework rule's § 600.1014 governs how fish buyers must deposit, and later disburse to NMFS, the fees which they have collected as well as how they must keep records of, and report about, collected fees. Under the framework rule's § 600.1014, fish buyers must, no less frequently than at the end of each business week, deposit collected fees through a date not more than two calendar days before the date of deposit in segregated and federally insured accounts. Fees shall be submitted to NMFS monthly and shall be due no later than fifteen (15) calendar days following the end of each calendar month. Fee collection reports must accompany these disbursements. Fish buyers must maintain specified fee collection records for at least 3 years and submit to NMFS annual reports of fee collection and disbursement activities by February 1 of each calendar year.

Under § 600.1015, the late charge to fish buyers for fee payment, collection, deposit, and/or disbursement shall be one and one-half (1.5) percent per month. The full late charge shall apply to the fee for each month or portion of a month that the fee remains unpaid.

To provide more accessible services, streamline collections, and save taxpayer dollars, fish buyers may disburse collected fee deposits to NMFS by using a secure Federal system on the Internet known as *Pay.gov*. *Pay.gov* enables subsector members to use their checking accounts to electronically disburse their collected fee deposits to NMFS. Subsector members who have access to the Internet should consider using this quick and easy collected fee disbursement method. Subsector members may access *Pay.gov* by going directly to *Pay.gov's* Federal website at: *https://www.pay.gov/paygov/.*

Subsector members who do not have access to the Internet or who simply do not wish to use the *Pay.gov* electronic system, must disburse collected fee deposits to NMFS by sending a check to our lockbox at:

NOAA Fisheries Longline Catcher Processor Non-pollock Buyback
P O Box 979060
St. Louis, MO 63197–9000

Subsector members must not forget to include with their disbursements the fee collection report applicable to each disbursement. Subsector members using *Pay.gov* will find an electronic fee collection report form to accompany electronic disbursements. Subsector members who do not use *Pay.gov* must include a hard copy fee collection report with each of their disbursements. Subsector members not using *Pay.gov* may also access the NMFS website for a PDF version of the fee collection report at: *http://www.nmfs.noaa.gov/mb/financial_services/buyback.htm.*

NMFS will, before the fee's effective date, separately mail a copy of this rule, along with detailed fee payment, collection, deposit, disbursement, recording, and reporting information and guidance, to each fish seller and fish buyer of whom NMFS has notice. The fact that any fish seller or fish buyer might not, however, receive from NMFS a copy of the notice or of the information and guidance does not relieve the fish seller or fish buyer from his fee obligations under the applicable regulations.

All parties interested in this action should carefully read the following framework rule sections, whose detailed provisions apply to the fee system for repaying the reduction program's loan:

1. § 600.1012;
2. § 600.1013;
3. § 600.1014;
4. § 600.1015;
5. § 600.1016; and
6. § 600.1017.

NMFS, in accordance with the framework rule's § 600.1013(d), establishes the initial fee for the program's reduction fishery as 2.0 cents per pound. NMFS will then separately mail notification to each affected fish seller and fish buyer of whom NMFS has notice. Until this notification, fish sellers and fish buyers do not have to either pay or collect the fee.

Please see the framework rule's § 600.1000 for the definition of ''delivery value'' and of the other terms relevant to this proposed rule. Each disbursement of the reduction loan's $35,000,000 principal amount began accruing interest as of the date of each such disbursement. The loan's interest rate is the applicable rate, plus 2 percent, which the U.S. Treasury determines at the end of fiscal year 2007.

## III. Classification

The Assistant Administrator for Fisheries, NMFS, determined that this proposed rule is consistent with the Magnuson-Stevens Fishery Conservation and Management Act, Consolidated Appropriations Act of 2005, and other applicable laws.

In compliance with the National Environmental Policy Act, NMFS prepared an EA for the reduction program's final implementing rule (September 29, 2006; 71 FR 57696). The EA discusses the impact of this proposed rule on the natural and human environment and integrates an RIR and a FRFA. The EA resulted in a finding of no significant impact. The EA considered, among other alternatives, the implementation of the fee payment and collection in this action. NMFS will send the EA, RIR, and FRFA to anyone who requests a copy (see **ADDRESSES**).

NMFS prepared an Initial Regulatory Flexibility Analysis (IRFA), as required by section 603 of the Regulatory Flexibility Act (RFA), to describe the economic impacts this proposed rule would have on small entities. This proposed rule does not duplicate or conflict with other Federal regulations.

### *IRFA Analysis*

The Small Business Administration has defined small entities as all fish harvesting businesses that are independently owned and operated, not dominant in its field of operation, and with annual receipts of $4 million or less. In addition, processors with 500 or fewer employees for related industries involved in canned or cured fish and seafood, or preparing fresh fish and seafood, are also considered small entities. Small entities within the scope of this proposed rule include individual U.S. vessels and dealers. There are no disproportionate impacts between large and small entities.

*Description of the Number of Small Entities*

The IRFA uses the most recent year of data available to conduct the analysis (2003). Most firms operating in the reduction fishery have annual gross revenues of less than $4 million. The IRFA analysis estimates that 24 of the remaining 36 active longline catcher processor vessels (i.e., 36 vessels constitute the post-reduction longline subsector) that participated in 2003 are considered small entities. The remaining 10 vessels are not considered small entities for purposes of the RFA. There is 1 additional fisherman with a permit but no vessel remaining in the longline subsector. The vessels that might be considered large entities were either affiliated under owners of multiple vessels or were catcher processors. However, little is known about the ownership structure of the vessels in the fleet, so it is possible that the IRFA overestimates the number of small entities. Because the final reduction program rule has not resulted in changes to allocation percentages and participation is voluntary, net effects are expected to be minimal relative to the status quo.

The economic impact to communities where non-pollock groundfish are landed and processed would be minimal because the harvest quotas and allocations would not be altered. Fewer vessels in the catcher processor fleet may mean that fewer on-shore fleet support services would be required in Seattle and in Dutch Harbor. The communities would see little change because total landings of non-pollock groundfish would remain at current levels. Some beneficial impacts may occur because this program has provided $35 million to successful offerors. Much of this could be reinvested in the various communities which serve as home ports to the vessels and a portion would be recovered through income taxes. Crew employment opportunities will be reduced when vessels were removed from the fishery. However, those vessels remaining in the fishery will likely experience increased fishing opportunities and higher per capita incomes.

The proposed rule's impact will be positive for both those whose offers NMFS has accepted, the selected offerors who received payments to stop fishing, and for post-reduction catcher processors whose landing fees repay the reduction loan. The owners whose offers NMFS accepted have relinquished their fishing licenses, reduction privilege vessels where appropriate, and fishing histories in exchange for payment. These payments ranged from $1.5 million for an inactive license that was not attached to a vessel, up to $11.8 million for the removal of both an active license and vessel from the fishery.

Those participants remaining in the fishery after the reduction program will incur additional fees of up to 5 percent of the ex-vessel production value of post-reduction landings. However, the additional costs could be mitigated by increased harvest opportunities by post-reduction fishermen. This is because removal of the vessels from the fishery creates immediate benefits to the longline catcher processor subsector by reducing competition pressure for each of the remaining vessels to catch fish. In theory, each of the vessels retaining their fishing licenses will be able to harvest more fish. This will likely result in net benefits to the subsector members who have voluntarily assumed the additional fees necessary to repay the reduction loan.

For example, even though each vessel could, on average, pay approximately $77,440 in fees, the net increase per vessel, on average could be approximately $302,560 more than they would have been able to make before the reduction program's implementation due to the increased opportunity to harvest the TAC. The referendum voters also cast votes unanimously in favor of the fee collection system, which demonstrated to NMFS the involved members of the fishing community have high confidence in the cost-effectiveness of this buyback program.

This rule, when implemented, would affect neither authorized BSAI Pacific cod ITAC and other non-pollock groundfish harvest levels or harvesting practices.

NMFS rejected the no action alternative considered in the EA for the final rule implementing the reduction program because NMFS would not be in compliance with the mandate of Section 219 of the Act to establish a reduction program. In addition, the longline catcher processor subsector of the non-pollock groundfish fishery would remain overcapitalized. Although too many vessels compete to catch the current subsector ITAC allocation, fishermen remain in the fishery because they have no other means to recover their significant capital investment. Overcapitalization reduces the potential net value that could be derived from the non-pollock groundfish resource, by dissipating rents, driving variable operating costs up, and imposing economic externalities. At the same time, excess capacity and effort diminish the effectiveness of current management measures (e.g. landing limits and seasons, bycatch reduction measures). Overcapitalization has diminished the economic viability of members of the fleet and increased the economic and social burden on fishery dependent communities.

It has been determined that this proposed rule is not significant for purposes of Executive Order 12866.

This proposed rule contains collection-of-information requirements subject to the Paperwork Reduction Act. OMB has approved these information collections under OMB control number 0648 AU42. NMFS estimates that the public reporting burden for these requirements will average two hours for submitting a monthly fee collection report and four hours for submitting an annual fish buyer report.

These response estimates include the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the information collection. Send comments regarding this burden estimate, or any other aspect of this data collection, including suggestions for reducing the burden, to both NMFS and OMB (see **ADDRESSES**).

Notwithstanding any other provision of the law, no person is required to respond to, and no person is subject to a penalty for failure to comply with, any information collection subject to the Paperwork Reduction Act unless that information collection displays a currently valid OMB control number.

**List of Subjects in 50 CFR Part 600**

Fisheries, Fishing capacity reduction, Fishing permits, Fishing vessels, Intergovernmental relations, Loan programs business, Reporting and recordkeeping requirements.

Dated: July 17, 2007.

**Samuel D. Rauch III,**

*Deputy Assistant Administrator for Regulatory Programs, National Marine Fisheries Service.*

For the reasons in the preamble, the National Marine Fisheries Service proposes to amend 50 CFR part 600 as follows:

## PART 600 MAGNUSON-STEVENS ACT PROVISIONS

1. The authority citation for part 600 continues to read as follows:

**Authority:** 5 U.S.C. 561 and 16 U.S.C. 1801 *et seq.*

2. Section 600.1106 is added to read as follows:

### § 600.1106 Longline catcher processor subsector Bering Sea and Aleutian Islands (BSAI) non-pollock groundfish species fee payment and collection system.

(a) *Purpose.* As authorized by Public Law 108 447, this section's purpose is to:

(1) In accordance with § 600.1012 of subpart L, establish:

(i) The borrower's obligation to repay a reduction loan, and

(ii) The loan's principal amount, interest rate, and repayment term; and

(2) In accordance with §§ 600.1013 through 600.1016 of subpart L, implement an industry fee system for the reduction fishery.

(b) *Definitions.* Unless otherwise defined in this section, the terms defined in § 600.1000 of subpart L and § 600.1105 of this subpart expressly apply to this section.

*Reduction fishery* means the longline catcher processor subsector of the BSAI non-pollock groundfish fishery that § 679.2 of this chapter defined as groundfish area/species endorsements.

(c) *Reduction loan amount.* The reduction loan's original principal amount is $35,000,000.

(d) *Interest accrual from inception.* Interest began accruing on the reduction loan from May 29, 2007, the date on which NMFS disbursed such loan.

(e) *Interest rate.* The reduction loan's interest rate shall be the applicable rate which the U.S. Treasury determines at the end of fiscal year 2007 plus 2 percent.

(f) *Repayment term.* For the purpose of determining fee rates, the reduction loan's repayment term is 30 years from May 29, 2007, but fees shall continue indefinitely for as long as necessary to fully repay the loan.

(g) *Reduction loan repayment.* (1) The borrower shall, in accordance with § 600.1012, repay the reduction loan;

(2) For the purpose of the fee collection, deposit, disbursement, and accounting requirements of this subpart, subsector members are deemed to be both the fish buyer and fish seller. In this case, all requirements and penalties of § 600.1013 of this subpart that are applicable to both a fish seller and a fish buyer shall equally apply to parties performing both functions;

(3) Subsector members in the reduction fishery shall pay and collect the fee amount in accordance with § 600.1105;

(4) Subsector members in the reduction fishery shall, in accordance with § 600.1014, deposit and disburse, as well as keep records for and submit reports about, the fees applicable to such fishery; except the requirements specified under paragraph (c) of this section concerning the deposit principal disbursement shall be made to NMFS no later than fifteen (15) calendar days following the end of each calendar month; and the requirements specified under paragraph (e) of this section concerning annual reports which shall be submitted to NMFS by February 1 of each calendar year; and

(5) The reduction loan is, in all other respects, subject to the provisions of §§ 600.1012 through 600.1017.

[FR Doc. E7–14118 Filed 7–19–07; 8:45 am]

BILLING CODE 3510–22–S

# Notices

Federal Register

Vol. 72, No. 139

Friday, July 20, 2007

This section of the FEDERAL REGISTER contains documents other than rules or proposed rules that are applicable to the public. Notices of hearings and investigations, committee meetings, agency decisions and rulings, delegations of authority, filing of petitions and applications and agency statements of organization and functions are examples of documents appearing in this section.

## DEPARTMENT OF AGRICULTURE

### Office of the Secretary

### Roadless Area Conservation National Advisory Committee

**AGENCY:** Office of the Secretary, USDA.

**ACTION:** Notice; request for nominations.

**SUMMARY:** The current terms of the members of the Roadless Area Conservation National Advisory Committee (RACNAC) will expire in September 2007. The Secretary invites nominations of persons to serve on this committee for a two year period, to run from September 2007 to September 2009. Nominations should describe and document the proposed member's qualifications for membership.

**DATES:** Nomination packages must include a signed and dated copy of form AD–755—Advisory Committee Membership Background Information. Form AD–755 may be obtained at *http://www.ocio.usda.gov/forms/ocio_forms.html*. Nominations must be received in writing by August 20, 2007.

**ADDRESSES:** Nominations for membership on the RACNAC may be sent via fax to the Director, Ecosystem Management Coordination at 202–205–1012, or via mail to the Director, Ecosystem Management Coordination, USDA Forest Service, 1400 Independence Ave., SW., Mail Stop 1104, Washington, DC 20250.

**FOR FURTHER INFORMATION CONTACT:** Jessica Call, RACNAC Coordinator, at *jessicacall@fs.fed.us* or (202) 205–1056, USDA Forest Service, 1400 Independence Avenue, SW., Mailstop 1104, Washington, DC 20250.

**SUPPLEMENTARY INFORMATION:** The purpose of the RACNAC is to provide advice and recommendations to the Secretary on the management and conservation of roadless areas, including, but not limited to, petitions by the States to the Secretary, or his designee, under the authority of the Administrative Procedure Act (5 U.S.C. 553(e) and 7 CFR 1.28). The RACNAC reviews submitted petitions and provides advice and recommendations to the Secretary. The RACNAC also provides advice and recommendations to the Secretary on any subsequent State-specific rulemakings.

The RACNAC consists of up to 15 members appointed by the Secretary of Agriculture. Officers or employees of the Forest Service may not serve as members of the Committee. The Committee chair shall be elected by the members. The RACNAC shall be composed of a balanced group of representatives of diverse national organizations who can provide insights into the major contemporary issues associated with the conservation and management of inventoried roadless areas. Members operate in a manner designed to establish a consensus of opinion in order to develop recommendations that reflect relevant needs and perspectives. Members seek to reach mutual agreement on a course of action on issues. Collectively, the members should represent a diversity of organizations and perspectives. Members will work together to draft recommendations that are representative of the diverse values and interests represented in the Committee.

Appointment to the RACNAC will be made by the Secretary of Agriculture. Equal opportunity practices will be followed in all appointments to the RACNAC. To ensure the recommendations of the RACNAC have taken into account the needs of the diverse groups served by the Department, membership will include, to the extent practicable, individuals with demonstrated ability to represent minorities, women and persons with disabilities.

Dated: July 13, 2007.

**Gilbert L. Smith Jr.,**

*Deputy Assistant Secretary for Administration.*

[FR Doc. E7–14016 Filed 7–19–07; 8:45 am]

**BILLING CODE 3410–11–P**

## DEPARTMENT OF AGRICULTURE

### Forest Service

### Kootenai National Forest, Rexford Ranger District, Montana; Young-Dodge Environmental Impact Statement

**AGENCY:** Forest Service, USDA.

**ACTION:** Notice of intent to prepare an environmental impact statement.

**SUMMARY:** The USDA—Forest Service will prepare an Environmental Impact Statement (EIS) to disclose the environmental effects of timber harvest, prescribed burning, road management, recreation improvements, and special use permits in the Young-Dodge Decision Area (Decision Area) on the Rexford Ranger District of the Kootenai National Forest. The Forest Service is seeking comments from Federal; State, and local agencies and individuals and organizations that may be interested in or affected by the proposed actions. The comments will be used to prepared the draft EIS (DEIS).

**DATES:** Written comments concerning the scope of the analysis must be postmarked by or received within 30 days following publication of this notice. The draft environmental impact statement is expected in April 2008.

**ADDRESSES:** Send written comments concerning the proposed action to Glen M. McNitt, District Ranger, Rexford Ranger District, 1299 U.S. Highway 93 N, Eureka, MT 59917. All comments received must contain: name of commenter, postal service mailing address, and date of comment.

**FOR FURTHER INFORMATION CONTACT:** Chris Fox, Interdisciplinary Team Leader, Rexford Ranger District, 1299 U.S. Highway 93N, Eureka, MT 59917.

**SUPPLEMENTARY INFORMATION:** The Decision Area is located approximately 15 miles northwest of Eureka, Montana, and contains approximately 37,900 acres of land within the Kootenai National Forest. Proposed activities include all or portions of the following areas: T.37N R.28W and part of T.37N R.29W, PMM, Lincoln County, Montana.

All proposed activities are outside the boundaries of any areas considered for inclusion to the National Wilderness System as recommended by the Kootenai National Forest Plan or by any past or present legislative wilderness proposals. A prescribed burn is proposed within the boundary of the Robinson Mountain Inventoried Roadless Area.

**Purpose and Need for Action**

The purpose and need for the project is to: (1) Reduce fuel accumulations, both inside and outside the Wildland-Urban Interface, to decrease the likelihood that fires would become stand-replacing wildfires; (2) Restore historical vegetation species and stand structure; and (3) Restore historical patch sizes. Other consideration are: (4) Identify the minimum transportation system necessary to provide safe, reasonable, and efficient access for Forest Service administrative activities and fire suppression, recreation use and public access, and private land owners and utility companies; (5) Manage the transportation system to reduce effects to threatened, endangered, sensitive, and management indicator species habitat and security; streams, riparian areas, and wetlands; big game winter range; and old growth habitat, and to minimize road maintenance costs; (6) Evaluate recreation facilities and opportunities to meet growing and anticipated demand; and (7) Evaluate existing and proposed Special Use Permits.

**Proposed Action**

The Forest Service proposes to use regeneration harvest (shelterwood and seedtree prescriptions) on approximately 2,000 acres, and commercial thinning on approximately 1,120 acres.

The Proposed Action would result in 26 openings over 40 acres, ranging from 41 to 1,121 acres. A 60-day public review period and approval by the Regional Forester for exceeding the 40-acre limitation for regeneration harvest would be required prior to the signing of the Record of Decision. This 60-day period is initiated with this Notice of Intent.

The Proposed Action includes approximately 2,660 acres of underburning following timber harvest, 460 acres of excavator piling and burning, and approximately 2,050 acres of prescribed burning without timber harvest. Approximately 1,650 acres will be mechanically pre-treated followed by prescribed burning. Additionally, the Proposed Action includes 31 acres of post and pole harvest, 366 acres of roadside salvage, and up to 200 acres of salvage of incidental mortality associated with prescribed burning.

The Proposed Action includes maintenance activities on portions of approximately 70 miles of road to meet Best Management Practices; decommissioning approximately 12 miles of roads currently restricted year-long to motorized vehicles; placing approximately 26 miles of roads, which are currently restrict year-long to motor vehicles, in intermittent stored service; placing seasonal restrictions on motorized vehicle use on approximately 6 miles of roads; adding approximately 9 miles of ''unauthorized'' roads to the National Forest Road System; and realigning and reconstructing approximately .25 miles of a road which is of poor standard and receiving heavy use.

The Proposed Action includes the construction of a boat ramp and installation of a rest room, and improvements to a trail.

The Proposed Action also includes a number of special use permits which will expire during the period this project will be implemented, and two proposed special use permits for utility lines.

The Proposed Action may require several project-specific Forest Plan amendments to meet the project's objectives:

An amendment to allow harvest in units adjacent to existing openings in Management Area (MA) 12 (Big Game Summer Range). The amendment would be needed to suspend Wildlife and Fish Standard #7 and Timber Standard #2 for this area. These standards state the movement corridors and adjacent hiding cover be retained.

The resulting opening sizes more closely correlate to natural disturbance patterns. Snags and down woody material would be left to provide wildlife habitat and maintain soil productivity.

A third amendment to allow the open road density in MA 12 to be managed at greater than 0.75 miles/square mile during project implementation may be required. The amendment would be necessary to suspend Facilities Standard #3, which states that open road density should be maintained at 0.75 miles/square mile.

**Possible Alternatives**

The Forest Service will consider a range of alternatives. One of these will be the ''no action'' alternative, in which none of the proposed activities will be implemented. Additional alternatives will be considered to achieve the project's purpose and need for action, and to respond to specific resource issues and public concerns.

**Responsible Official**

Paul Bradford, Forest Supervisor, Kootenai National Forest, 1101 Highway 2 West, Libby, MT 59923.

**Nature of the Decision To Be Made**

This project will provide approximately 10 MMBF of commercial forest products, reduce hazardous fuels within and outside the wildland-urban interface, provide for recreation facilities, and evaluate special-use permits.

**Scoping Process**

In March 2007, efforts were made to involve the public in considering management opportunities within the Decision Area. Open houses were held on March 14 and 15, 2007. A scoping package was mailed for public review on May 4, 2007. An open house was held on May 16, 2007, and field trips were held on May 17, 2007 and June 28, 2007. The proposal will be included in the quarterly Schedule of Proposed Actions. Comments received prior to this notice will be included in the documentation for the EIS.

**Preliminary Issues**

A preliminary issue identified reflects concern over the amount of regeneration harvest (approximately 2,000 acres) proposed in watersheds were logging has occurred and grizzly bears and lynx may be present.

**Comment Requested**

This Notice of intent initiates the scoping process which guides the development of the environment impact statement. At this stage of the planning process, site-specific public comments are being requested to determine the scope of the analysis, and identify significant issues and alternatives to the Proposed Action.

**Early Notice of Importance of Public Participation in Subsequent Environmental Review**

A draft environmental impact statement will be prepared for comment. The comment period on the draft environmental impact will be 45 days from the date the Environmental Protection Agency published the notice of availability in the **Federal Register**.

The Forest Service believes it is important to give reviewers notice of several court rulings related to public participating in the environmental review process. First, reviewers of DEIS' must structure their participation in the environmental review of the proposal so that it is meaningful and alerts an agency to the reviewer's position and contentions. *Vermont Yankee Nuclear*

*Power Corp.* v. *NRDC*, 435 U.S. 519, 553 (1978). Also, environmental objections that could be raised at the draft environmental impact statement stage may be waived or dismissed by the Courts. *City of Angoon* v. *Hodel*, 803, F.2d 1016, 1022 (9th Cir. 1986) and *Wisconsin Heritages, Inc.* v. *Harris*, 490 F. Supp. 1334, 1339 (E.D. Wis. 1980). Because of these court rulings, it is very important that those interested in this proposed action participate by the close of the 45 day comment period so that substantive comments and objections are made available to the Forest Service at a time when it can meaningfully consider and respond to them in the final environmental impact statement.

To assist the Forest Service in identifying and considering issues and concerns on the proposed action, comments on the draft environmental impact statement should be as specific as possible. It is also helpful if comments refer to specific pages or chapters of the draft statements. Comments may also address the adequacy of the draft environmental impact statement or the merits of the alternatives formulated and discussed in the statement. Reviewers may wish to refer to the Council on Environmental Quality Regulations for implementing the procedural provisions of The National Environmental Policy Act at 40 CFR 1503.3 in addressing these points. Comments received, including the names and addresses of those who comment, will be considered part of the public record on this proposal and will be available for public inspection.

(**Authority:** 40 CFR 1501.7 and 1508.22; Forest Service Handbook 1909.15, Section 21)

Dated: July 10, 2007.

**Paul Bradford,**

*Forest Supervisor.*

[FR Doc. 07–3519 Filed 7–19–07; 8:45 am]

**BILLING CODE 3410–11–M**

## COMMITTEE FOR PURCHASE FROM PEOPLE WHO ARE BLIND OR SEVERELY DISABLED

### Procurement List; Proposed Additions and Deletions

**ACTION:** Proposed Additions to and Deletions from the Procurement List.

**SUMMARY:** The Committee is proposing to add to the Procurement List a product and a service to be furnished by nonprofit agencies employing persons who are blind or have other severe disabilities, and to delete a product and a service previously furnished by such agencies.

*Comments Must Be Received On or Before:* August 19, 2007.

**ADDRESSES:** Committee for Purchase From People Who Are Blind or Severely Disabled, Jefferson Plaza 2, Suite 10800, 1421 Jefferson Davis Highway, Arlington, Virginia 22202–3259.

**FOR FURTHER INFORMATION OR TO SUBMIT COMMENTS CONTACT:** Kimberly M. Zeich, Telephone: (703) 603–7740, Fax: (703) 603–0655, or e-mail *CMTEFedReg@jwod.gov.*

**SUPPLEMENTARY INFORMATION:** This notice is published pursuant to 41 U.S.C. 47(a) (2) and 41 CFR 51–2.3. Its purpose is to provide interested persons an opportunity to submit comments on the proposed actions.

### Additions

If the Committee approves the proposed additions, the entities of the Federal Government identified in this notice for each product or service will be required to procure the products and services listed below from nonprofit agencies employing persons who are blind or have other severe disabilities.

*Regulatory Flexibility Act Certification*

I certify that the following action will not have a significant impact on a substantial number of small entities. The major factors considered for this certification were:

1. If approved, the action will not result in any additional reporting, recordkeeping or other compliance requirements for small entities other than the small organizations that will furnish the products and services to the Government.
2. If approved, the action will result in authorizing small entities to furnish the products and services to the Government.
3. There are no known regulatory alternatives which would accomplish the objectives of the Javits-Wagner-O'Day Act (41 U.S.C. 46–48c) in connection with the products and services proposed for addition to the Procurement List.

Comments on this certification are invited. Commenters should identify the statement(s) underlying the certification on which they are providing additional information.

*End of Certification*

The following products and service are proposed for addition to Procurement List for production by the nonprofit agencies listed:

**Products:**

*Portfolio, Writing, CAMO (ACU Digitized):*
*NSN:* 7510–00–NIB–0753—Memo size;
*NSN:* 7510–00–NIB–0764—Letter Size;
*NSN:* 7510–00–NIB–0765—Memo Size;
*NSN:* 7510–00–NIB–0766—Letter Size;
*NSN:* 7510–00–NIB–0805—US Army Logo. Memo Size;
*NSN:* 7510–00–NIB–0808—Pocket Size.
*Coverage:* A-List for the total Government requirements as specified by the General Services Administration.
*Portfolio, Writing, Custom Color and Logo:*
*NSN:* 7510–00–NIB–0806—Memo Size.
*Coverage:* B-List for the requirements of the General Services Administration.
*NPA:* New York City Industries for the Blind, Inc., Brooklyn, NY.
*Contracting Activity:* General Services Administration, Office Supplies & Paper Products Acquisition Ctr, New York, NY.

**Service:**

*Service Type/Location:* Commissary Warehousing, Warehouse Building 3335, 3335 Central Avenue, Suite 100, Eielson AFB, AK.
*NPA:* Fairbanks Resource Agency, Fairbanks, AK.
*Contracting Activity:* Defense Commissary Agency, Fort Lee, VA.

### Deletions

*Regulatory Flexibility Act Certification*

I certify that the following action will not have a significant impact on a substantial number of small entities. The major factors considered for this certification were:

1. If approved, the action may result in additional reporting, recordkeeping or other compliance requirements for small entities.
2. If approved, the action may result in authorizing small entities to furnish the services to the Government.
3. There are no known regulatory alternatives which would accomplish the objectives of the Javits-Wagner-O'Day Act (41 U.S.C. 46–48c) in connection with the services proposed for deletion from the Procurement List.

*End of Certification*

The following product and service are proposed for deletion from the Procurement List:

**Product:**

*Tube, Mailing and Filing:*
*NSN:* 8110–00–969–5406—Tube, Mailing and Filing.
*NPA:* MacDonald Training Center, Inc., Tampa, FL.
*Contracting Activity:* General Services Administration, Office Supplies & Paper Products Acquisition Ctr, New York, NY.

**Service:**

*Service Type/Location:* Commissary Shelf Stocking, Custodial & Warehousing, Marine Corps Base, Twenty-Nine Palms, CA.
*NPA:* PRIDE Industries, Inc., Roseville, CA.
*Contracting Activity:* Defense Commissary

Agency, Fort Lee, VA.

**Kimberly M. Zeich,**

*Director, Program Operations.*

[FR Doc. E7–14047 Filed 7–19–07; 8:45 am]

**BILLING CODE 6353–01–P**

## COMMITTEE FOR PURCHASE FROM PEOPLE WHO ARE BLIND OR SEVERELY DISABLED

## Procurement List; Additions and Deletions

**AGENCY:** Committee for Purchase From People Who Are Blind or Severely Disabled.

**ACTION:** Additions to and deletions from the Procurement List.

**SUMMARY:** This action adds to the Procurement List a product and services to be furnished by nonprofit agencies employing persons who are blind or have other severe disabilities, and deletes from the Procurement List products and services previously furnished by such agencies.

**DATES:** *Effective Date:* August 19, 2007.

**ADDRESSES:** Committee for Purchase From People Who Are Blind or Severely Disabled, Jefferson Plaza 2, Suite 10800, 1421 Jefferson Davis Highway, Arlington, Virginia 22202–3259.

**FOR FURTHER INFORMATION CONTACT:** Kimberly M. Zeich, Telephone: (703) 603–7740, Fax: (703) 603–0655, or e-mail *CMTEFedReg@jwod.gov.*

**SUPPLEMENTARY INFORMATION:**

### Additions

On May 25, 2007, the Committee for Purchase From People Who Are Blind or Severely Disabled published notice (72 FR 8149; 29295–29296) of proposed additions to the Procurement List.

After consideration of the material presented to it concerning capability of qualified nonprofit agencies to provide the products and services and impact of the additions on the current or most recent contractors, the Committee has determined that the products and services listed below are suitable for procurement by the Federal Government under 41 U.S.C. 46–48c and 41 CFR 51–2.4.

*Regulatory Flexibility Act Certification*

I certify that the following action will not have a significant impact on a substantial number of small entities. The major factors considered for this certification were:

1. The action will not result in any additional reporting, recordkeeping or other compliance requirements for small entities other than the small organizations that will furnish the products and services to the Government.

2. The action will result in authorizing small entities to furnish the products and services to the Government.

3. There are no known regulatory alternatives which would accomplish the objectives of the Javits-Wagner-O'Day Act (41 U.S.C. 46–48c) in connection with the products and services proposed for addition to the Procurement List.

*End of Certification*

Accordingly, the following product and services are added to the Procurement List:

**Product:**

*Hood, Anti-Flash, Firemens,*
*NSN:* 4210–01–493–4694—DAF–S–1 (20% KEVLAR/80% FR Rayon)—2 ply.
*Coverage:* C–List—100% for the requirements of the Defense Supply Center Philadelphia, Philadelphia, PA.
*NPA:* Dawn Enterprises, Inc., Blackfoot, ID.
*Contracting Activity:* Defense Supply Center Philadelphia, Philadelphia, PA.

**Services:**

*Service Type/Location:* Custodial & Grounds Maintenance, Joseph P. Kinneary Federal Courthouse, 85 Marconi Boulevard, Columbus, OH.
*NPA:* The Alpha Group of Delaware, Inc., Delaware, OH.
*Contracting Activity:* General Services Administration, Public Building Service, Region 5, Cleveland, OH.
*Service Type/Location:* Custodial Services, Fort AP Hill, Camp Anderson, Bowling Green, VA.
*NPA:* Rappahannock Goodwill Industries, Inc., Fredericksburg, VA.
*Contracting Activity:* Army Contracting Agency, Aberdeen Proving Ground, MD.
*Service Type/Location:* Custodial Services, U.S. Department of Agriculture, Animal and Plant Health Inspection Service, 843 13th Court—Unit 7, Riviera Beach, FL.
*NPA:* Gulfstream Goodwill Industries, Inc., West Palm Beach, FL.
*Contracting Activity:* U.S. Department of Agriculture, Animal & Plant Health Inspection Service-MRP–BS ASD, Minneapolis, MN.
*Service Type/Location:* Custodial/Grounds Maintenance, Syracuse Military Entrance Processing Station (MEPS), 6001 E. Mallory Road, Building 710, Syracuse, NY.
*NPA:* Oswego Industries, Inc., Fulton, NY.
*Contracting Activity:* AFRC—Niagara, Niagara Falls, NY.
*Service Type/Location:* Document Destruction, Internal Revenue Service, 550 W. Fort Street, Boise, ID.
*NPA:* Western Idaho Training Company, Inc., Caldwell, ID.
*Contracting Activity:* U.S. Department of Treasury, Internal Revenue Service, San Francisco, CA
*Service Type/Location:* Janitorial/Landscaping Services, U.S. Department of Agriculture, Agricultural Research Service, 430 West Health Services Drive, Davis, CA.
*NPA:* PRIDE Industries, Inc., Roseville, CA.
*Contracting Activity:* U.S. Department of Agriculture, Agricultural Research Service-Pacific West Area, Albany, CA.
*Service Type/Location:* Supply/Warehouse/HAZMAT Service, Meridian Naval Air Station, 224 Allen Rd, Meridian, MS.
*NPA:* South Texas Lighthouse for the Blind, Corpus Christi, TX.
*Contracting Activity:* Fleet and Industrial Supply Center, Jacksonville, FL.

### Deletions

On February 23, and May 25, 2007, the Committee for Purchase From People Who Are Blind or Severely Disabled published notice (72 FR 8149; 29296) of proposed deletions to the Procurement List.

After consideration of the relevant matter presented, the Committee has determined that the products and services listed below are no longer suitable for procurement by the Federal Government under 41 U.S.C. 46–48c and 41 CFR 51–2.4.

*Regulatory Flexibility Act Certification*

I certify that the following action will not have a significant impact on a substantial number of small entities. The major factors considered for this certification were:

1. The action may result in additional reporting, recordkeeping or other compliance requirements for small entities.

2. The action may result in authorizing small entities to furnish the products and services to the Government.

3. There are no known regulatory alternatives which would accomplish the objectives of the Javits-Wagner-O'Day Act (41 U.S.C. 46–48c) in connection with the products and services deleted from the Procurement List.

*End of Certification*

Accordingly, the following products and services are deleted from the Procurement List:

**Products:**

*PCU, Level 7 Loft Jacket—Type 2:*
*NSN:* 8415–00–NSH–1647—Size LL,
*NSN:* 8415–00–NSH–1649—Size XLL,
*NSN:* 8415–00–NSH–1652—Size XXLL,
*NSN:* 8415–00–NSH–1654—Size XXXLL.
*NPA:* Southeastern Kentucky Rehabilitation Industries, Inc., Corbin, KY.
*Contracting Activity:* U.S. Army RDECOM Acquisition Center, Natick, MA.
*Pencil, Mechanical, Push-Action (MD):*
*NSN:* 7520–01–484–3907—Pencil, Mechanical, Push-Action (MD),

*NSN:* 7520–01–484–3908—Pencil, Mechanical, Push-Action (MD).
*NPA:* San Antonio Lighthouse for the Blind, San Antonio, TX.
*Contracting Activity:* General Services Administration, Office Supplies & Paper Products Acquisition Ctr, New York, NY.

**Services:**

*Service Type/Location:* Grounds Maintenance, Hill Air Force Base, Hill Air Force Base, UT.
*NPA:* Pioneer Adult Rehabilitation Center Davis County School District, Clearfield, UT.
*Contracting Activity:* Hill Air Force Base, UT.
*Service Type/Location:* Janitorial/Custodial, Navy Exchange Command Accounting (CAC), Norfolk, VA.
*NPA:* Didlake, Inc., Manassas, VA.
*Service Type/Location:* Janitorial/Custodial, Navy Exchange Command Uniform Support Center, Bldg 1545, Crossways Blvd, Chesapeake, VA.
*NPA:* Portco, Inc., Portsmouth, VA.
*Contracting Activity:* Navy Exchange Service Command (NEXCOM), Virginia Beach, VA.
*Service Type/Location:* Microfilming, Department of Treasury, Financial Management Services, Hyattsville, MD.
*NPA:* Didlake, Inc., Manassas, VA.
*Contracting Activity:* Department of the Treasury, Washington, DC.

**Kimberly M. Zeich,**

*Director, Program Operations.*

[FR Doc. E7–14048 Filed 7–19–07; 8:45 am]

BILLING CODE 6353–01–P

## COMMISSION ON CIVIL RIGHTS

### Agenda and Notice of Public Meeting of the Connecticut Advisory Committee

Notice is hereby given, pursuant to the provisions of the rules and regulations of the U.S. Commission on Civil Rights (Commission), and the Federal Advisory Committee Act (FACA), that a planning meeting of the Connecticut Advisory Committee to the Commission will convene at 12 p.m. and adjourn at 2 p.m. on Thursday, August 2, 2007 in the conference room of Oak Hill, located at 120 Holcomb Street, Hartford, Connecticut. The purpose of the planning meeting is for the committee to discuss its school choice report and plan for the committee's September briefing on school choice.

Members of the public are entitled to submit written comments; the comments must be received in the Eastern Regional Office by August 9, 2007. The address is 624 Ninth Street, NW., Suite 740, Washington, DC 20425. Persons wishing to e-mail their comments, or to present their comments verbally at the meeting, or who desire additional information should contact Barbara de La Viez, Civil Rights Analyst, Eastern Regional Office, U.S. Commission on Civil Rights at (202) 376–7533 [TDY 202–376–8116], or by e-mail at *bdelaviez@usccr.gov*.

Hearing-impaired persons who will attend the meeting and require the services of a sign language interpreter should contact the Regional Office at least ten (10) working days before the scheduled date of the meeting.

Records generated from this meeting may be inspected and reproduced at the Eastern Regional Office, as they become available, both before and after the meeting. Persons interested in the work of this advisory committee are advised to go to the Commission's Web site, *http://www.usccr.gov*, or to contact the Eastern Regional Office at the above e-mail or street address.

The meeting will be conducted pursuant to the provisions of the rules and regulations of the Commission and FACA.

Dated in Washington, DC, July 17, 2007.

**Ivy Davis,**

*Acting Chief, Regional Programs Coordination Unit.*

[FR Doc. E7–14073 Filed 7–19–07; 8:45 am]

BILLING CODE 6335–02–P

## DEPARTMENT OF COMMERCE

### Bureau of Industry and Security

### Technical Advisory Committees; Notice of Recruitment of Private Sector Members

**SUMMARY:** Six Technical Advisory Committees (TACs) advise the Department of Commerce on the technical parameters for export controls applicable to dual-use commodities and technology and on the administration of those controls. The TACs are composed of representatives from industry and Government representing diverse points of view on the concerns of the exporting community. Industry representatives are selected from firms producing a broad range of goods, technologies, and software presently controlled for national security, non-proliferation, foreign policy, and short supply reasons or that are proposed for such controls, balanced to the extent possible among large and small firms.

TAC members are appointed by the Secretary of Commerce and serve terms of not more than four consecutive years. The membership reflects the Department's commitment to attaining balance and diversity. TAC members must obtain secret-level clearances prior to appointment. These clearances are necessary so that members may be permitted access to the classified information needed to formulate recommendations to the Department of Commerce. Each TAC meets approximately 4 times per year. Members of the Committees will not be compensated for their services. The six TACs are responsible for advising the Department of Commerce on the technical parameters for export controls and the administration of those controls within the following areas: Information Systems TAC: Control List Categories 3 (electronics), 4 (computers), and 5 (telecommunications and information security); Materials TAC: Control List Category 1 (materials, chemicals, microorganisms, and toxins); Materials Processing Equipment TAC: Control List Category 2 (materials processing); Regulations and Procedures TAC: The Export Administration Regulations (EAR) and procedures for implementing the EAR; Sensors and Instrumentation TAC: Control List Category 6 (sensors and lasers); Transportation and Related Equipment TAC; Control List Categories 7 (navigation and avionics), 8 (marine), and 9 (propulsion systems, space vehicles, and related equipment). To respond to this recruitment notice, please send a copy of your resume to Ms. Yvette Springer at *Yspringer@bis.doc.gov.*

*Deadline:* This Notice of Recruitment will be open for one year from its date of publication in the **Federal Register.**

**FOR FURTHER INFORMATION CONTACT:** Ms. Yvette Springer on (202) 482–2813.

Dated: July 16, 2007.

**Yvette Springer,**

*Committee Liaison Officer.*

[FR Doc. 07–3544 Filed 7–19–07; 8:45 am]

BILLING CODE 3510–JT–M

## DEPARTMENT OF COMMERCE

### International Trade Administration

**[A–570–831]**

### Amended Final Results of Antidumping Duty Administrative Review: Fresh Garlic From the People's Republic of China

**AGENCY:** Import Administration, International Trade Administration, Department of Commerce.

**SUMMARY:** On June 22, 2007, the Department of Commerce (''Department'') published in the **Federal Register** the final results of the eleventh administrative review and concurrent new shipper reviews of the antidumping duty order on fresh garlic from the Peoples Republic of China

(''PRC''). *See Fresh Garlic from the People's Republic of China: Final Results and Partial Rescission of the Eleventh Administrative Review and New Shipper Reviews,* 72 FR 34438 (June 22, 2007) ''(*Final Results*'') and accompanying Issues and Decision Memorandum. The period of review (''POR'') covered November 1, 2004, through October 31, 2005. We are amending our *Final Results* to correct ministerial errors made in the calculation of the antidumping duty margin for Jinxiang Shanyang Freezing Storage Co., Ltd. (''Shanyang''), pursuant to section 751(h) of the Tariff Act of 1930, as amended (''Act'').

**EFFECTIVE DATE:** July 20, 2007.

**FOR FURTHER INFORMATION CONTACT:**
Irene Gorelik, AD/CVD Operations, Office 9, Import Administration, International Trade Administration, U.S. Department of Commerce, 14th Street and Constitution Avenue, NW., Washington, DC 20230; telephone: (202) 482–6905.

**SUPPLEMENTARY INFORMATION:**

## Background

On June 22, 2007, the Department published the *Final Results* and corresponding issues and decision memorandum. *See* ''Memorandum from Stephen J. Caleys, Deputy Assistant Secretary for Import Administration, to David M. Spooner, Assistant Secretary for Import Administration, Subject: Antidumping Duty Order on Fresh Garlic from the People's Republic of China: Issues and Decision Memorandum for the Eleventh Administrative Review and New Shipper Reviews'' (''Final Decision Memo'').

On June 18, 2007, Fresh Garlic Producers Association and its individual members, Christopher Ranch L.L.C., the Garlic Company, Valley Garlic, and Vessey and Company, (''Petitioners'') submitted a letter requesting a two-day extension to submit ministerial error comments. Accordingly, the Department extended the deadline by two days to June 20, 2007, to submit any ministerial error allegations with respect to the *Final Results.* On June 20, 2007, Shanyang filed timely clerical error allegations with respect to the Department's antidumping duty margin calculation in the *Final Results.* On June 25, 2007, Petitioners filed timely rebuttal comments to Shanyang's clerical error allegations.

## Scope to Order

The products covered by this antidumping duty order are all grades of garlic, whole or separated into constituent cloves, whether or not peeled, fresh, chilled, frozen, provisionally preserved, or packed in water or other neutral substance, but not prepared or preserved by the addition of other ingredients or heat processing. The differences between grades are based on color, size, sheathing, and level of decay. The scope of this order does not include the following: (a) Garlic that has been mechanically harvested and that is primarily, but not exclusively, destined for non-fresh use; or (b) garlic that has been specially prepared and cultivated prior to planting and then harvested and otherwise prepared for use as seed. The subject merchandise is used principally as a food product and for seasoning. the subject garlic is currently classifiable under subheadings 0703.20.0010, 0703.20.0020, 0703.20.0090, 0710.80.7060, 0710.80.9750, 0711.90.6000, and 2005.90.9700 of the Harmonized Tariff Schedule of the United States (''HTSUS''). Although the HTSUS subheadings are provided for convenience and customs purposes, our written description of the scope of this order is dispositive. In order to be excluded from the antidumping duty order, garlic entered under the HTSUS subheadings listed above that is: (1) Mechanically harvested and primarily, but not exclusively, destined for non-fresh use; or (2) specially prepared and cultivated prior to planting and then harvested and otherwise prepared for use as seed must be accompanied by declarations to U.S. Customs and Border Protection (''CBP'') to that effect.

## Ministerial Errors

A ministerial error is defined in section 751(h) of the Act and further clarified in 19 CFR 351.224(f) as ''an error in addition, subtraction, or other arithmetic function, clerical error resulting from inaccurate copying, duplication, or the like, and any other similar type of unintentional error which the Secretary considers ministerial.''

After analyzing all interested parties' comments, we have determined, in accordance with 19 CFR 351.224(e), that ministerial errors existed in certain calculations for Shanyang in the *Final Results.* Correction of these errors results in a change to Shanyang's final antidumping duty margin. Additionally, the rate change for Shanyang also affects the deposit rates for the companies subject to the administrative review which are receiving a separate rate.[1] The rate for the PRC-wide entity remains unchanged. For a detailed discussion of these ministerial errors, as well as the Department's analysis, see ''Memorandum to James C. Doyle, Director, Office 9, Import Administration, through Alex Villanueva, Program Manager, Office 9, Import Administration, from Irene Gorelik, Case Analyst, Office 9, Subject: Analysis of Ministerial Error Allegations,'' (July 12, 2007) (''Ministerial Error Allegation Memorandum''). the Ministerial Error Allegation Memorandum is on file in the Central Records Unit, room B–099 in the main Department building.

Therefore, in accordance with section 751(h) of the Act and 19 CFR 351.224(e), we are amending the *Final Results* of the administrative review of fresh garlic from the PRC. The revised weighted-average dumping margins are detailed below. For company-specific calculation, see ''Memorandum from Irene Gorelik, Case Analyst, through Alex Villanueva, to the File, Subject: Analysis Memorandum for the Amended Final Results for Shanyang,'' (July 12, 2007). The revised final weighted-average dumping margins are as follows:

FRESH GARLIC FROM THE PRC-WEIGHTED-AVERAGE DUMPING MARGINS

| Manufacturer exporter | Weighted-average deposit rate (percent) |
|---|---|
| Jinxiang Shanyang Freezing Storage Co., Ltd | 24.73 |
| Fook Huat Tong Kee Foodstuffs Co., Ltd | 9.84 |
| Heze Ever-Best International Trade Co., Ltd | 9.84 |

[1] The companies subject to the administrative review which are receiving a separate rate are: Fook Huat Tong Kee Foodstuffs Co., Ltd.; Heze Ever-Best International Trade Co., Ltd.; Huaiyang Hongda Dehydrated Vegetable Company; Linshu Dading Private Agricultural Products Co., Ltd.; and Taiyan Ziyang Food Co., Ltd.

FRESH GARLIC FROM THE PRC-WEIGHTED-AVERAGE DUMPING MARGINS—Continued

| Manufacturer exporter | Weighted-average deposit rate (percent) |
|---|---|
| Huaiyang Hongda Dehydrated Vegetable Company | 9.84 |
| Linshu Dading Private Agricultural Products Co., Ltd | 9.84 |
| Taiyan Ziyang Food Co., Ltd | 9.84 |

The Department shall determine, and CBP shall assess, antidumping duties on all appropriate entries based on the amended final results. For details on the assessment of antidumping duties on all appropriate entries, *see Final Results*.

These amended final results are published in accordance with section 751(h) and 777(i)(1) of the Act.

Dated: July 12, 2007.

**David A. Spooner,**

*Assistant Secretary for Import Administration.*

[FR Doc. 07–3518 Filed 7–19–07; 8:45 am]

**BILLING CODE 3510–DS–M**

---

## DEPARTMENT OF COMMERCE

### International Trade Administration

**(A–475–703)**

### Notice of Preliminary Results of Antidumping Duty Administrative Review: Granular Polytetrafluoroethylene Resin From Italy

**AGENCY:** Import Administration, International Trade Administration, Department of Commerce.

**EFFECTIVE DATE:** July 20, 2007.

**FOR FURTHER INFORMATION CONTACT:** Salim Bhabhrawala, at (202) 482–1784; AD/CVD Operations, Office 1, Import Administration, International Trade Administration, U.S. Department of Commerce, 14th Street & Constitution Avenue, NW, Washington, DC 20230.

**SUMMARY:** The Department of Commerce (the Department) is conducting an administrative review of the antidumping duty order on granular polytetrafluoroethylene resin (PTFE) from Italy, covering the period August 1, 2005, through July 31, 2006. We preliminarily determine that sales of subject merchandise by Solvay Solexis, Inc. and Solvay Solexis S.p.A (collectively, Solvay) have been made below normal value (NV). If these preliminary results are adopted in our final results, we will instruct U.S. Customs and Border Protection (CBP) to assess antidumping duties on appropriate entries based on the difference between the export price (EP) and the NV. Interested parties are invited to comment on these preliminary results.

**SUPPLEMENTARY INFORMATION:**

#### Background

On August 30, 1988, the Department published in the **Federal Register** the antidumping duty order on granular PTFE resin from Italy. *See Antidumping Duty Order; Granular Polytetrafluoroethylene Resin from Italy*, 53 FR 33163 (August 30, 1988). On August 1, 2005, the Department issued a notice of opportunity to request an administrative review of this order. *See Antidumping or Countervailing Duty Order, Finding, or Suspended Investigation; Opportunity To Request Administrative Review*, 71 FR 43441–43443 (August 1, 2006). In accordance with 19 CFR 351.213(b), Solvay requested an administrative review. On September 29, 2006, the Department published the notice of initiation of this antidumping duty administrative review, covering the period August 1, 2005, through July 31, 2006 (the period of review, or POR). *See Initiation of Antidumping and Countervailing Duty Administrative Reviews*, 71 FR 57465 (September 29, 2006).

On September 29, 2006, the Department issued its antidumping questionnaire to Solvay, specifying that the responses to Section A and Sections B–E would be due on October 20, 2006, and November 6, 2006, respectively.[1] The Department received timely responses to Sections A–D of the initial antidumping questionnaire and associated supplemental questionnaires.

On May 1, 2007, the Department published a notice of a 71-day extension of the preliminary results of this administrative review. *See Granular Polytetrafluoroethylene Resin From Italy: Notice of Extension of Time Limit for the Preliminary Results of Antidumping Duty Administrative Review*, 72 FR 23802. This notice extended the deadline for the preliminary results to July 13, 2007.

#### Scope of the Order

The product covered by this order is granular PTFE resin, filled or unfilled. This order also covers PTFE wet raw polymer exported from Italy to the United States. *See Granular Polytetrafluoroethylene Resin From Italy; Final Affirmative Determination of Circumvention of Antidumping Duty Order*, 58 FR 26100 (April 30, 1993). This order excludes PTFE dispersions in water and fine powders. During the period covered by this review, such merchandise was classified under item number 3904.61.00 of the Harmonized Tariff Schedule of the United States (HTSUS). We are providing this HTSUS number for convenience and CBP purposes only. The written description of the scope remains dispositive.

#### Fair Value Comparisons

We compared the constructed export price (CEP) to the NV, as described in the *Constructed Export Price* and *Normal Value* sections of this notice. Pursuant to section 777A(d)(2) of the Tariff Act of 1930, as amended (the Act), we compared the CEPs of individual transactions to contemporaneous monthly weighted–average prices of sales of the foreign like product.

We first attempted to compare contemporaneous sales of products sold in the United States and the comparison market that were identical with respect to the following characteristics: type, filler, percentage of filler, and grade. Where we were unable to compare sales of identical merchandise, we compared U.S. sales with comparison market sales of the most similar merchandise.

#### Constructed Export Price

For all sales to the United States, we calculated CEP, as defined in section 772(b) of the Act, because all sales to unaffiliated parties were made after importation of the subject merchandise

[1] Section A of the questionnaire requests general information concerning a company's corporate structure and business practices, the merchandise under review that it sells, and the manner in which it sells that merchandise in all of its markets. Section B requests a complete listing of all home market sales, or, if the home market is not viable, of sales in the most appropriate third-country market (this Section is not applicable to respondents in non-market economy cases). Section C requests a complete listing of U.S. sales. Section D requests information on the cost of production of the foreign like product and the constructed value of the merchandise under review. Section E requests information on further manufacturing.

into the United States through the respondent's affiliate, Solvay Solexis, Inc. We based CEP on the packed, delivered prices to unaffiliated purchasers in the United States, net of billing adjustments. We adjusted these prices for movement expenses, including international freight, marine insurance, brokerage and handling in the United States, U.S. inland freight, U.S. warehousing, and U.S. customs duties, in accordance with section 772(c)(2)(A) of the Act.

In accordance with section 772(d)(1) of the Act, we deducted selling expenses incurred by the affiliated reseller. These expenses include credit, inventory carrying costs, and indirect selling expenses incurred by Solvay Solexis, Inc. See Memorandum from Salim Bhabhrawala, Senior International Trade Compliance Analyst, to Nancy Decker, Program Manager, Re: Preliminary Results Calculation Memorandum, dated July 13, 2007 (Analysis Memo).

**Normal Value**

*A. Selection of Comparison Markets*

In order to determine whether there was a sufficient volume of sales of granular PTFE resin in the home market to serve as a viable basis for calculating NV, we compared Solvay's volume of home market sales of the foreign like product to the volume of U.S. sales of the subject merchandise, in accordance with section 773(a)(1)(C) of the Act. Because the aggregate volume of home market sales of the foreign like product was greater than five percent of the respective aggregate volume of U.S. sales for the subject merchandise, we determined that the home market provided a viable basis for calculating NV. Therefore, in accordance with section 773(a)(1)(B)(i) of the Act, we based NV on the prices at which the foreign like product was first sold for consumption in the exporting country, in the usual commercial quantities and in the ordinary course of trade.

*B. Cost of Production Analysis*

Because we disregarded below–cost sales in the calculation of the final results of the 2000–2001 administrative review, the most recently completed review of PTFE at the time of initiation of this review, with respect to Solvay, we had reasonable grounds to believe or suspect that home market sales of the foreign like product by Solvay had been made at prices below the cost of production (COP) during the period of this review. See section 773(b)(2)(A)(ii) of the Act. Therefore, pursuant to section 773(b)(1) of the Act, we initiated a COP investigation regarding home market sales. Solvay calculated its model–specific costs of production on a POR basis.

*1. Calculation of COP*

In accordance with section 773(b)(3) of the Act, we calculated the model–specific, weighted–average COP based on the sum of the cost of materials and fabrication for the foreign like product, plus amounts for general and administrative expenses, interest expenses, selling expenses, and packing costs.

*2. Test of Home Market Sales Prices*

We compared the weighted–average COP to the home market sales of the foreign like product, as required under section 773(b) of the Act, in order to determine whether these sales had been made at prices below the COP within an extended period of time (i.e., a period of one year) in substantial quantities and whether such prices were sufficient to permit the recovery of all costs within a reasonable period of time.

On a model–specific basis, we compared the COP to home market prices, less any rebates, discounts, applicable movement charges, and direct and indirect selling expenses.

*3. Adjustments to Respondent's Data*

We relied on the COP data submitted by Solvay in its cost questionnaire response except for general and administrative (G&A) expenses. We adjusted Solvay's G&A expenses to be based on its normal books and records, in accordance with Italian Generally Accepted Accounting Principles. *See* Analysis Memo.

*4. Results of the COP Test*

We disregarded below–cost sales where: (1) 20 percent or more of Solvay's sales of a given product during the POR were made at prices below the COP, because such sales were made within an extended period of time in substantial quantities in accordance with sections 773(b)(2)(B) and (C) of the Act; and (2) based on comparisons of price to weighted–average COPs for the POR, we determined that the below–cost sales of the product were at prices which would not permit recovery of all costs within a reasonable time period, in accordance with section 773(b)(2)(D) of the Act. We found that Solvay made sales below cost, and we disregarded such sales where appropriate.

*C. Calculation of Normal Value Based on Comparison–Market Prices*

We determined home market prices net of price adjustments (e.g., early payment discounts and rebates). Where applicable, we made adjustments for packing and movement expenses, in accordance with sections 773(a)(6)(A) and (B) of the Act. In order to adjust for differences in packing between the two markets, we deducted home market packing costs from NV and added U.S. packing costs. We also made adjustments for differences in costs attributable to differences in physical characteristics of the merchandise, pursuant to section 773(a)(6)(C)(ii) of the Act, and for other differences in the circumstances of sale (COS) in accordance with section 773(a)(6)(C)(iii) of the Act (*i.e.*, differences in credit expenses). Finally, we made a CEP–offset adjustment to the NV for indirect selling expenses pursuant to section 773(a)(7)(B) of the Act, as discussed in the Level of Trade/CEP Offset section below.

*D. Level of Trade/CEP Offset*

In accordance with section 773(a)(1)(B) of the Act, to the extent practicable, we determine NV based on sales at the same level of trade in the comparison market as the level of trade of the U.S. sales. The comparison market level of trade is that of the starting–price sales in the comparison market. For CEP sales, such as those made by Solvay in this review, the U.S. level of trade is the level of the constructed sale from the exporter to the importer.

To determine whether comparison market sales are at a different level of trade than that of the U.S. sales, we examine stages in the marketing process and selling functions along the chain of distribution between the producer and the unaffiliated customer. If the comparison–market sales are at a different level of trade and the difference affects price comparability, as manifested in a pattern of consistent price differences between the sales on which NV is based and comparison–market sales at the level of trade of the export transaction, we make a level–of-trade adjustment under section 773(a)(7)(A) of the Act. Finally, if the NV level is more remote from the factory than the CEP level and there is no basis for determining whether the difference in the levels between NV and CEP affects price comparability, we adjust NV under section 773(a)(7)(B) of the Act (the CEP–offset provision). *See, e.g., Industrial Nitrocellulose From the United Kingdom; Notice of Final Results of Antidumping Duty Administrative Review*, 65 FR 6148, 6151 (February 8, 2000) (*Industrial Nitrocellulose*).

For purpose of this review, we obtained information from Solvay about the marketing involved in the reported U.S. sales and in the home market sales, including a description of the selling activities performed by Solvay for each channel of distribution. In identifying levels of trade for CEP and for home market sales, we considered the selling functions reflected in the CEP, after the deduction of expenses and profit under section 772(d) of the Act, and those reflected in the home market starting price before making any adjustments. We expect that, if claimed levels of trade are the same, the functions and activities of the seller should be similar. Conversely, if a party claims that levels of trade are different for different groups of sales, the functions and activities of the seller should be dissimilar.

The record evidence in this review indicates that the home market and the CEP levels of trade for Solvay have not changed from the 2004–2005 review,[2] the most recently completed review in this case. As explained below, we determined in this review that, as in the prior 2004–2005 administrative review, there was one home market level of trade and one U.S. level of trade (*i.e.*, the CEP level of trade).

In the home market, Solvay sold directly to fabricators. These sales primarily entailed selling activities such as technical assistance, engineering services, research and development, technical programs, and delivery services. Given this fact pattern, we found that all home market sales were made at a single level of trade. In determining the level of trade for the U.S. sales, we only considered the selling activities reflected in the price after making the appropriate adjustments under section 772(d) of the Act. *See, e.g., Industrial Nitrocellulose*, 65 FR at 6150. The CEP level of trade involves minimal selling functions such as invoicing and the occasional exchange of personnel between Solvay and its U.S. affiliate. Given this fact pattern, we found that all U.S. sales were made at a single level of trade.

Based on a comparison of the home market level of trade and this CEP level of trade, we find the home market sales to be at a different level of trade from, and more remote from the factory than, the CEP sales. Section 773(a)(7)(A) of the Act directs us to make an adjustment for difference in levels of trade where such differences affect price comparability. However, we were unable to quantify such price differences from information on the record. Because we have determined that the home–market level of trade is more remote from the factory than the CEP level of trade, and because the data necessary to calculate a level–of-trade adjustment are unavailable, we made a CEP–offset adjustment to NV pursuant to section 773(a)(7)(B) of the Act.

[2] *See Notice of Final Results of Antidumping Duty Administrative Review: Granular Polytetrafluoroethylene Resin from Italy*, 72 FR 1980 (January 17, 2007).

**Currency Conversion**

We made currency conversions into U.S. dollars in accordance with section 773A of the Act, based on exchange rates in effect on the date of the U.S. sale, as certified by the Federal Reserve Bank.

**Preliminary Results of Review**

As a result of this review, we preliminarily determine that the following weighted–average margin exists for the period August 1, 2005, through July 31, 2006:

| Producer | Weighted–Average Margin (Percentage) |
|---|---|
| Solvay Solexis, Inc. and Solvay Solexis S.p.A (collectively, Solvay) | 35.35 |

In accordance with 19 CFR 351.224(b), the Department will disclose its weighted average antidumping margin calculations within 10 days of public announcement of these preliminary results. An interested party may request a hearing within 30 days of publication of these preliminary results. *See* 19 CFR 351.310(c). Any hearing, if requested, will be held 44 days after the date of publication, or the first working day thereafter. Interested parties may submit case briefs and/or written comments no later than 30 days after the date of publication of these preliminary results. *See* 19 CFR 351.309(c). Rebuttal briefs and rebuttals to written comments, limited to issues raised in such briefs or comments, may be filed no later than 37 days after the date of publication. See 19 CFR 351.309(d). Parties who submit arguments are requested to submit with the argument: (1) a statement of the issue; (2) a brief summary of the argument; and (3) a table of authorities. Further, the parties submitting written comments should provide the Department with an additional copy of the public version of any such comments on diskette.

The Department will issue the final results of this administrative review, which will include the results of its analysis of issues raised in any such comments, within 120 days of publication of these preliminary results.

**Assessment**

Upon completion of this administrative review, pursuant to 19 CFR 351.212(b), the Department will calculate an assessment rate on all appropriate entries. We will calculate importer–specific duty assessment rates based on the ratio of the total amount of antidumping duties calculated for the examined sales to the total quantity of the sales for that importer. Where the assessment rate is above *de minimis*, we will instruct CBP to assess duties on all entries of subject merchandise by that importer.

The Department clarified its ''automatic assessment'' regulation on May 6, 2003. *See Antidumping and Countervailing Duty Proceedings: Assessment of Antidumping Duties*, 68 FR 23954 (May 6, 2003). This clarification will apply to entries of subject merchandise during the POR produced by the company included in these preliminary results for which the reviewed company did not know their merchandise was destined for the United States. In such instances, we will instruct CBP to liquidate unreviewed entries at the all–others rate if there is no rate for the intermediate company or companies involved in the transaction.

**Cash Deposit Requirements**

The following deposit rates will be effective upon publication of the final results of this administrative review for all shipments of PTFE from Italy entered, or withdrawn from warehouse, for consumption on or after the publication date, as provided by section 751(a)(1) of the Act: (1) the cash deposit rate listed above for Solvay will be the rate established in the final results of this review, except if a rate is less than 0.5 percent, and therefore *de minimis*, the cash deposit rate will be zero; (2) for previously reviewed or investigated companies not listed above, the cash deposit rate will continue to be the company–specific rate published for the most recent period; (3) if the exporter is not a firm covered in this review, a prior review, or the less–than–fair–value (LTFV) investigation, but the manufacturer is, the cash deposit rate will be the rate established for the most recent period for the manufacturer of the merchandise; and (4) if neither the exporter nor the manufacturer is a firm covered in this or any previous review conducted by the Department, the cash deposit rate will be 46.46 percent, the ''all others'' rate established in the LTFV investigation. *See* 53 FR 26096 (July 11, 1988). These cash deposit requirements, when imposed, shall remain in effect until further notice.

**Notification to Importers**

This notice serves as a preliminary reminder to importers of their responsibility under 19 CFR 351.402(f)(2) to file a certificate regarding the reimbursement of antidumping duties prior to liquidation of the relevant entities during this review period. Failure to comply with this requirement could result in the Secretary's presumption that reimbursement of antidumping duties occurred and the subsequent assessment of double antidumping duties.

This determination is issued and published in accordance with sections 751(a)(1) and 777(i)(1) of the Act.

Dated: June 13, 2007.

**Joseph A. Spetrini,**

*Deputy Assistant Secretary for Import Administration.*

[FR Doc. E7–14087 Filed 7–19–07; 8:45 am]

BILLING CODE 3510–DS–S

## DEPARTMENT OF COMMERCE

### International Trade Administration

**A–337–806**

### IQF Red Raspberries from Chile: Final Results of Sunset Review and Revocation of Order

**AGENCY:** Import Administration, International Trade Administration, Department of Commerce.

**SUMMARY:** On June 1, 2007, the Department of Commerce (Department) initiated this sunset review of the antidumping duty order on IQF red raspberries from Chile (72 FR 30544). Because the domestic interested parties did not participate in this review, the Department is revoking this antidumping duty order.

**EFFECTIVE DATE:** July 9, 2007

**FOR FURTHER INFORMATION CONTACT:** Nancy Decker or Brandon Farlander, Import Administration, International Trade Administration, U.S. Department of Commerce, 14th Street and Constitution Avenue, NW, Washington, DC 20230; telephone: (202) 482–0196 or (202) 482–0182, respectively.

**SUPPLEMENTARY INFORMATION:**

**Background**

On July 9, 2002, the Department issued an antidumping duty order on IQF red raspberries from Chile. *See Notice of Antidumping Duty Order: IQF Red Raspberries from Chile*, 67 FR 45460 (July 9, 2002). On June 1, 2007, the Department initiated a sunset review of this order. *See Initiation of Five-year (Sunset) Reviews*, 72 FR 30544, 30545 (June 1, 2007).

We did not receive a notice of intent to participate from domestic interested parties in this sunset review by the deadline date. As a result, the Department determined that no domestic interested party intends to participate in the sunset review, and on June 21, 2007, we notified the International Trade Commission, in writing, that we intended to issue a final determination revoking this antidumping duty order. *See* 19 CFR 351.218(d)(1)(iii)(B)(1) and (B)(2).

**Scope of the Order**

The products covered by this order are imports of IQF whole or broken red raspberries from Chile, with or without the addition of sugar or syrup, regardless of variety, grade, size or horticulture method (*e.g.*, organic or not), the size of the container in which packed, or the method of packing. The scope of the order excludes fresh red raspberries and block frozen red raspberries (*i.e.*, puree, straight pack, juice stock, and juice concentrate).

The merchandise subject to this order is currently classifiable under subheading 0811.20.2020 of the Harmonized Tariff Schedule of the United States (''HTSUS''). Although the HTSUS subheading is provided for convenience and customs purposes, the written description of the merchandise under the order is dispositive.

**Determination to Revoke**

Pursuant to section 751(c)(3)(A) of the Tariff Act of 1930, as amended (the Act), and 19 CFR 351.218(d)(1)(iii)(B)(3), if no domestic interested party files a notice of intent to participate, the Department shall, within 90 days after the initiation of the review, issue a final determination revoking the order. Because the domestic interested parties did not file a notice of intent to participate in this sunset review, the Department finds that no domestic interested party is participating in this sunset review. Therefore, we are revoking this antidumping duty order. The effective date of revocation is July 9, 2007, the fifth anniversary of the date the Department published this antidumping duty order. *See* 19 CFR 351.222(i)(2)(i).

**Effective Date of Revocation**

Pursuant to section 751(c)(3)(A) of the Act and 19 CFR 351.222(i)(2)(i), the Department will instruct U.S. Customs and Border Protection to terminate the suspension of liquidation of the merchandise subject to this order entered, or withdrawn from warehouse, on or after July 9, 2007. Entries of subject merchandise prior to the effective date of revocation will continue to be subject to suspension of liquidation and antidumping duty deposit requirements. The Department will complete any pending administrative reviews of this order and will conduct administrative reviews of subject merchandise entered prior to the effective date of revocation in response to appropriately filed requests for review.

This five-year (sunset) review and notice are in accordance with sections 751(c) and 777(i)(1) of the Act.

Dated: July 13, 2007.

**Joseph A. Spetrini,**

*Deputy Assistant Secretary for Import Administration.*

[FR Doc. E7–14085 Filed 7–19–07; 8:45 am]

BILLING CODE 3510–DS–S

## DEPARTMENT OF COMMERCE

### National Institute of Standards and Technology

### Request for Nominations for Members To Serve on National Institute of Standards and Technology Federal Advisory Committees

**AGENCY:** National Institute of Standards and Technology, Department of Commerce.

**ACTION:** Notice.

**SUMMARY:** The National Institute of Standards and Technology (NIST) invites and requests nomination of individuals for appointment to its eight existing Federal Advisory Committees: Advanced Technology Program Advisory Committee, Board of Overseers of the Malcolm Baldrige National Quality Award, Judges Panel of the Malcolm Baldrige National Quality Award, Information Security and Privacy Advisory Board, Manufacturing Extension Partnership National Advisory Board, National Construction Safety Team Advisory Committee, Advisory Committee on Earthquake Hazards Reduction, and Visiting Committee on Advanced Technology. NIST will consider nominations received in response to this notice for appointment to the Committees, in addition to nominations already received.

**DATES:** Nominations for all committees will be accepted on an ongoing basis and will be considered as and when vacancies arise.

**ADDRESSES:** See below.

**SUPPLEMENTARY INFORMATION:**

**Advanced Technology Program (ATP) Advisory Committee**

*Addresses:* Please submit nominations to Mr. Marc Stanley, National Institute of Standards and Technology, 100 Bureau Drive, Mail Stop 4700, Gaithersburg, MD 20899–4700. Nominations may also be submitted via Fax to 301–869–1150. Additional information regarding the Committee, including its charter and current membership list may be found on its electronic home page at: *http://www.atp.nist.gov/adv_com/ac_menu.htm.*

*For Further Information Contact:* Mr. Marc G. Stanley, National Institute of Standards and Technology, 100 Bureau Drive, Mail Stop 4700, Gaithersburg, MD 20899–4700; telephone 301–975–262; fax 301–869–1150; or via e-mail at *marc.stanley@nist.gov.*

*Committee Information:* The Committee will advise the Director of the National Institute of Standards and Technology (NIST) on ATP programs, plans, and policies.

The Committee will consist of not fewer than six nor more than thirteen members appointed by the Director of NIST, and its membership will be balanced to reflect the wide diversity of technical disciplines and industrial sectors represented in ATP projects.

The Committee will function solely as an advisory body, in compliance with the provisions of the Federal Advisory Committee Act.

**Authority:** Federal Advisory Committee Act, 5 U.S.C. App. 2, and General Services Administration Rule, 41 CFR subpart 101–6.10.

**Board of Overseers of the Malcolm Baldrige National Quality Award**

*Addresses:* Please submit nominations to Harry Hertz, Director, Baldrige National Quality Program, NIST, 100 Bureau Drive, Mail Stop 1020, Gaithersburg, MD 20899–1020. Nominations may also be submitted via Fax to 301–975–4967. Additional information regarding the Committee, including its charter, current membership list, and executive summary may be found on its electronic home page at: *http://www.baldrige.nist.gov.*

*For Further Information Contact:* Harry Hertz, Director, Baldrige National Quality Program and Designated Federal Officer, NIST, 100 Bureau Drive, Mail Stop 1020, Gaithersburg, MD 20899–1020; telephone 301–975–2361; Fax 301–948–4967; or via e-mail at *harry.hertz@nist.gov.*

*Committee Information:* The Board was established in accordance with 15 U.S.C. 3711a(d)(2)(B), pursuant to the Federal Advisory Committee Act (5 U.S.C. App. 2).

*Objectives and Duties*

1. The Board shall review the work of the private sector contractor(s), which assists the Director of the National Institute of Standards and Technology (NIST) in administering the Award. The Board will make such suggestions for the improvement of the Award process as it deems necessary.

2. The Board shall provide a written annual report on the results of Award activities to the Secretary of Commerce, along with its recommendations for the improvement of the Award process.

3. The Board will function solely as an advisory committee under the Federal Advisory Committee Act.

4. The Board will report to the Director of NIST and the Secretary of Commerce.

*Membership*

1. The Board will consist of approximately eleven members selected on a clear, standardized basis, in accordance with applicable Department of Commerce guidance and for their preeminence in the field of organizational performance management. There will be a balanced representation from U.S. service, manufacturing, education, health care industries, and the nonprofit sector.

2. The Board will be appointed by the Secretary of Commerce and will serve at the discretion of the Secretary. The term of office of each Board member shall be three years. All terms will commence on March 1 and end on February 28 of the appropriate year.

*Miscellaneous*

1. Members of the Board shall serve without compensation, but may, upon request, be reimbursed travel expenses, including per diem, as authorized by 5 U.S.C. 5701 *et seq.*

2. The Board will meet twice annually, except that additional meetings may be called as deemed necessary by the NIST Director or by the Chairperson. Meetings are one day in duration.

3. Board meetings are open to the public. Board members do not have access to classified or proprietary information in connection with their Board duties.

*Nomination Information:*

1. Nominations are sought from the private and public sector as described above.

2. Nominees should have established records of distinguished service and shall be familiar with the quality improvement operations of manufacturing companies, service companies, small businesses, education, health care, and nonprofits. The category (field of eminence) for which the candidate is qualified should be specified in the nomination letter. Nominations for a particular category should come from organizations or individuals within that category. A summary of the candidate's qualifications should be included with the nomination, including (where applicable) current or former service on Federal advisory boards and Federal employment. In addition, each nomination letter should state that the person agrees to the nomination, acknowledges the responsibilities of serving on the Board, and will actively participate in good faith in the tasks of the Board. Besides participation at meetings, it is desired that members be able to devote the equivalent of seven days between meetings to either developing or researching topics of potential interest, and so forth, in furtherance of their Board duties.

3. The Department of Commerce is committed to equal opportunity in the workplace and seeks a broad-based and diverse Board membership.

**Judges Panel of the Malcolm Baldrige National Quality Award**

*Addresses:* Please submit nominations to Harry Hertz, Director, Baldrige National Quality Program, NIST, 100 Bureau Drive, Mail Stop 1020, Gaithersburg, MD 20899–1020. Nominations may also be submitted via Fax to 301–975–4967. Additional information regarding the Committee, including its charter, current membership list, and executive summary may be found on its electronic home page at: *http://www.baldrige.nist.gov.*

*For Further Information Contact:* Harry Hertz, Director, Baldrige National Quality Program and Designated Federal Official, NIST, 100 Bureau Drive, Mail Stop 1020, Gaithersburg, MD 20899–1020; telephone 301–975–2361; Fax 301–975–4967; or via e-mail at *harry.hertz@nist.gov.*

*Committee Information:* The Judges Panel was established in accordance with 15 U.S.C. 3711a(d)(1), the Federal Advisory Committee Act (5 U.S.C. App. 2), and The Malcolm Baldrige National Quality Improvement Act of 1987 (Pub. L. 101–107).

*Objectives and Duties*

1. The Judges Panel will ensure the integrity of the Malcolm Baldrige National Quality Award selection process by reviewing the results of

examiners' scoring of written applications, and then voting on which applicants merit site visits by examiners to verify the accuracy of claims made by applicants.

2. The Judges Panel will ensure that individuals on site visit teams for the Award finalists have no conflict of interest with respect to the applicants. The Panel will also review recommendations from site visits and recommend Award recipients.

3. The Judges Panel will function solely as an advisory body, and will comply with the Provision of the Federal Advisory Committee Act.

4. The Panel will report to the Director of NIST.

*Membership*

1. The Judges Panel is composed of at least nine, and not more than twelve, members selected on a clear, standardized basis, in accordance with applicable Department of Commerce guidance. There will be a balanced representation from U.S. service and manufacturing industries, education, health care, and nonprofits and will include members familiar with performance improvement in their area of business.

2. The Judges Panel will be appointed by the Secretary of Commerce and will serve at the discretion of the Secretary. The term of office of each Panel member shall be three years. All terms will commence on March 1 and end on February 28 of the appropriate year.

*Miscellaneous*

1. Members of the Judges Panel shall serve without compensation, but may, upon request, be reimbursed travel expenses, including per diem, as authorized by 5 U.S.C. 5701 *et seq.*

2. The Judges Panel will meet three times per year. Additional meetings may be called as deemed necessary by the NIST Director or by the Chairperson. Meetings are one to four days in duration. In addition, each Judge must attend an annual three-day Examiner training course.

3. Committee meetings are closed to the public pursuant to Section 10(d) of the Federal Advisory Committee Act,. 5 U.S.C. App. 2, as amended by Section 5(c) of the Government in the Sunshine Act, Public Law 94–409, and in accordance with Section 552b(c)(4) of Title 5, United States Code. Since the members of the Judges Panel examine records and discuss Award applicant data, the meeting is likely to disclose trade secrets and commercial or financial information obtained from a person that may be privileged or confidential.

*Nomination Information*

1. Nominations are sought from all U.S. service and manufacturing industries, education, health care, and nonprofits as described above.

2. Nominees should have established records of distinguished service and shall be familiar with the performance improvement operations of manufacturing companies, service companies, small businesses, education, health care, and nonprofit organizations. The category (field of eminence) for which the candidate is qualified should be specified in the nomination letter. Nominations for a particular category should come from organizations or individuals within that category. A summary of the candidate's qualifications should be included with the nomination, including (where applicable) current or former service on federal advisory boards and federal employment. In addition, each nomination letter should state that the person agrees to the nomination, acknowledge the responsibilities of serving on the Judges Panel, and will actively participate in good faith in the tasks of the Judges Panel. Besides participation at meetings, it is desired that members be either developing or researching topics of potential interest, reading Baldrige applications, and so forth, in furtherance of their Committee duties.

3. The Department of Commerce is committed to equal opportunity in the workplace and seeks a broad-based and diverse Judges Panel membership.

**Information Security and Privacy Advisory Board (ISPAB)**

*Addresses:* Please submit nominations to Pauline Bowen, NIST, 100 Bureau Drive, Mail Stop 8930, Gaithersburg, MD 20899–8930. Nominations may also be submitted via fax to 301–975–4007, Attn: ISPAB Nominations. Additional information regarding the Board, including its charter and current membership list, may be found on its electronic home page at: *http://csrc.nist.gov/ispab/.*

*For Further Information Contact:* Pauline Bowen, ISPAB Designated Federal Official, NIST, 100 Bureau Drive, Mail Stop 8930, Gaithersburg, MD 20899–8930; telephone 301–975–2938; fax: 301–975–8670; or via e-mail at *pauline.bowen@nist.gov.*

*Committee Information:* The ISPAB was originally chartered as the Computer System Security and Privacy Advisory Board (CSSPAB) by the Department of Commerce pursuant to the Computer Security Act of 1987 (Pub. L. 100–235). As a result of the E-Government Act of 2002 (Pub. L. 107–347), Title III, the Federal Information Security Management Act of 2002, Section 21 of the National Institute of Standards and Technology Act (15 U.S.C. 278g–4) the Board's charter was amended. This amendment included the name change of the Board.

*Objectives and Duties*

The objectives and duties of the ISPAB are:

1. To identify emerging managerial, technical, administrative, and physical safeguard issues relative to information security and privacy.

2. To advise the NIST, the Secretary of Commerce and the Director of the Office of Management and Budget on information security and privacy issues petaining to Federal Government information systems, including thorough review of proposed standards and guidelines developed by NIST.

3. To annually report its findings to the Secretary of Commerce, the Director of the Office of Management and Budget, the Director of the National Security Agency, and the appropriate committees of the Congress.

4. To function solely as an advisory body, in accordance with the provisions of the Federal Advisory Committee Act.

*Membership*

The ISPAB is comprised of twelve members, in addition to the Chairperson. The membership of the Board includes:

1. Four members from outside the Federal Government eminent in the information technology industry, at least one of whom is representative of small or medium sized companies in such industries.

2. Four members from outside the Federal Government who are eminent in the fields of information technology, or related disciplines, but who are not employed by or representative of a producer of information technology equipment; and

3. Four members from the Federal Government who have information system management experience, including experience in information security and privacy; at least one of these members shall be from the National Security Agency.

*Miscellaneous*

Members of the ISPAB are not paid for their service, but will, upon request, be allowed travel expenses in accordance with Subchapter I of Chapter 57 of Title 5, United States Code, while otherwise performing duties at the request of the Board

Chairperson, while away from their homes or a regular place of business.

Meetings of the Board are two to three days in duration and are held quarterly. The meetings primarily take place in the Washington, DC metropolitan area but may be held at such locations and at such time and place as determined by the majority of the Board.

Board meetings are open to the public and members of the press usually attend. Members do not have access to classified or proprietary information in connection with their Board duties.

*Nomination Information:* Nominations are being accepted in all three categories described above.

Nominees should have specific experience related to information security or electronic privacy issues, particularly as they pertain to Federal information technology. Letters of nominations should include the category of membership for which the candidate is applying and a summary of the candidate's qualifications for that specific category. Also include (where applicable) current or former service on Federal advisory boards and any Federal employment. Each nomination letter should state that the person agrees to the nomination, acknowledges the responsibilities of serving on the ISPAB, and that they will actively participate in good faith in the tasks of the ISPAB.

Besides participation at meetings, it is desired that members be able to devote a minimum of two days between meetings to developing draft issue papers, researching topics of potential interest, and so forth in furtherance of their Board duties.

Selection of ISPAB members will not be limited to individuals who are nominated. Nominations that are received and meet the requirements will be kept on file to be reviewed as Board vacancies occur.

Nominees must be U.S. citizens.

The Department of Commerce is committed to equal opportunity in the workplace and seeks a broad-based and diverse ISPAB membership.

**Manufacturing Extension Partnership (MEP) National Advisory Board**

*Addresses:* Please submit nominations to Ms. Karen Lellock, National Institute of Standards and Technology, 100 Bureau Drive, Mail Stop 4800, Gaithersburg, MD 20899–4800. Nominations may also be submitted via fax to 301–963–6556. Additional information regarding the Board, including its charter and current membership list may be found on its electronic home page at: *http://www.mep.nist.gov/about-mep/advisory-board.html.*

*For Further Information Contact:* Ms. Karen Lellock, National Institute of Standards and Technology, 100 Bureau Drive, Mail Stop 4800, Gaithersburg, MD 20899–4800; telephone 301–975–4269, fax 301–963–6556; or via e-mail at *karen.lellock@nist.gov.*

*Committee Information:* The Board will advise the Director of the National Institute of Standards and Technology (NIST) on MEP programs, plans and policies.

The Board will consist of five to eleven individuals appointed by the Director of the NIST under the advisement of the Director of MEP. Membership on the Board shall be balanced to represent the views and needs of customers, providers, and other involved in industrial extension throughout the United States.

The Board will function solely as an advisory body in compliance with the provisions of the Federal Advisory Committee Act.

**Authority:** Federal Advisory Committee Act, 5 U.S.C. App. 2, and General Services Administration Rule, 41 CFR subpart 101–6.10.

**National Construction Safety Team Advisory Committee**

*Addresses:* Please submit nominations to Stephen Cauffman, National Construction Safety Team Advisory Committee, National Institute of Standards and Technology, 100 Bureau Drive, Mail Stop 8611, Gaithersburg, MD 20899–8611. Nominations may also be submitted via FAX to 301–869–6275.

*For Further Information Contact:* Stephen Cauffman, National Construction Safety Team Advisory Committee, National Institute of Standards and Technology, 100 Bureau Drive, Mail Stop 8611, Gaithersburg, MD 20899–8611, telephone 301–975–6051, fax 301–869–6275; or via e-mail at *stephen.cauffman@nist.gov.*

*Committee Information:* The Committee was established in accordance with the National Construction Safety Team Act, Public Law 107–231 and the Federal Advisory Committee Act (5 U.S.C. App. 2).

*Objectives and Duties*

1. The Committee shall advise the Director of the National Institute of Standards and Technology (NIST) on carrying out the National Construction Safety Team Act (Act), review and provide advice on the procedures developed under section 2(c)(1) of the Act, and review and provide advice on the reports issued under section 8 of the Act.

2. The Committee functions solely as an advisory body, in accordance with the provisions of the Federal Advisory Committee Act.

3. The Committee shall report to the Director of NIST.

4. The Committee shall provide a written annual report, through the Director of the NIST Building and Fire Research Laboratory (BFRL) and the Director of NIST, to the Secretary of Commerce for submission to the Congress, to be due at a date to be agreed upon by the Committee and the Director of NIST. Such report will provide an evaluation of National Construction Safety Team activities, along with recommendations to improve the operation and effectiveness of National Construction Safety Teams, and an assessment of the implementation of the recommendations of the National Construction Safety Teams and of the Committee. In addition, the Committee may provide reports at strategic stages of an investigation, at its discretion or at the request of the Director of NIST, through the Director of the BFRL and the Director of NIST, to the Secretary of Commerce.

*Membership*

1. The Committee will be composed of not fewer than five nor more than ten members that reflect a wide balance of the diversity of technical disciplines and competencies involved in the National Construction Safety Teams investigations. Members shall be selected on the basis of established records of distinguished service in their professional community and their knowledge of issues affecting the National Construction Safety Teams.

2. The Director of the NIST shall appoint the members of the Committee, and they will be selected on a clear, standardized basis, in accordance with applicable Department of Commerce guidance.

*Miscellaneous*

1. Members of the Committee will not be paid for their services, but will, upon request, be allowed travel and per diem expenses in accordance with 5 U.S.C. 5701 *et seq.*, while attending meetings of the Committee or of its subcommittees, or while otherwise performing duties at the request of the chairperson, while away from their homes or a regular place of business.

2. The Committee will meet at least once per year at the call of the Chair. Additional meetings may be called whenever one-third or more of the members so request it in writing or whenever the Chair or the Director of NIST requests a meeting.

3. Committee meetings will be open to the public except when a closed session is held in accordance with 5 U.S.C. 552b(c)(6), because divulging information discussed in those portions of the meetings is likely to reveal information of a personal nature where disclosure would constitute a clearly unwarranted invasion of personal privacy. All other portions of the meetings are open to the public.

*Nomination Information:*

1. Nominations are sought from all fields involved in issues affecting National Construction Safety Teams.

2. Nominees should have established records of distinguished service. The field of expertise that the candidate represents he/she is qualified should be specified in the nomination letter. Nominations for a particular field should come from organizations or individuals within that field. A summary of the candidate's qualifications should be included with the nomination, including (where applicable) current or former service on federal advisory boards and federal employment. In addition, each nomination letter should state that the person agrees to the nomination, acknowledges the responsibilities of serving on the Committee, and will actively participate in good faith in the tasks of the Committee.

3. The Department of Commerce is committed to equal opportunity in the workplace and seeks a broad-based and diverse Committee membership.

**Advisory Committee on Earthquake Hazards Reduction (ACEHR)**

*Addresses:* Please submit nominations to Tina Faecke, Administrative Officer, National Earthquake Hazards Reduction Program, National Institute of Standards and Technology, 100 Bureau Drive, Mail Stop 8630, Gaithersburg, MD 20899–8630. Nominations may also be submitted via Fax to 301–975–5433 or e-mail at *tina.faecke@nist.gov.* Additional information regarding the Committee, including its charter and executive summary may be found on its electronic home page at: *http://www.nehrp.gov.*

*For Further Information Contact:* Dr. Jack Hayes, Director, National Earthquake Hazards Reduction Program, National Institute of Standards and Technology, 100 Bureau Drive, Mail Stop 8610, Gaithersburg, MD 20899–8610, telephone 301–975–5640, fax 301–975–4032; or via e-mail at *jack.hayes@nist.gov.*

*Committee Information:* The Committee was established in accordance with the National Earthquake Hazards Reduction Program Reauthorization Act, Public Law 108–360 and the Federal Advisory Committee Act (5 U.S.C. App. 2).

*Objectives and Duties*

1. The Committee will assess trends and developments in the science and engineering of earthquake hazards reduction, effectiveness of the Program in carrying out the activities under section 103(a)(2) of the Act, the need to revise the Program, the management, coordination, implementation, and activities of the Program.

2. The Committee functions solely as an advisory body, in accordance with the provisions of the Federal Advisory Committee Act.

3. The Committee shall report to the Director of NIST.

4. Not later than one year after the first meeting of the Committee, and at least once every two years thereafter, the Committee shall report to the Director of NIST, on its findings of the assessments and its recommendations for ways to improve the Program. In developing recommendations, the Committee shall consider the recommendations of the United States Geological Survey Scientific Earthquake Studies Advisory Committee.

*Membership*

1. The Committee will consist of not fewer than 11 not more than 15 members, who reflect a wide diversity of technical disciplines, competencies, and communities involved in earthquake hazards reduction. Members shall be selected on the basis of established records of distinguished service in their professional community and their knowledge of issues affecting the National Earthquake Hazards Reduction Program.

2. The Director of NIST shall appoint the members of the Committee, and they will be selected on a clear, standardized basis, in accordance with applicable Department of Commerce guidance.

3. The term of office of each member of the Committee shall be three years, except that vacancy appointments shall be for the remainder of the unexpired term of the vacancy and that the initial members shall have staggered terms such that the committee will have approximately 1/3 new or reappointed members each year.

4. No committee member may be an ''employee'' as defined in subparagraphs (A) through (F) of section 7342(a)(1) of Title 5 of the United States Code.

*Miscellaneous*

1. Members of the Committee will not be compensated for their services, but will, upon request, be allowed travel and per diem expenses in accordance with 5 U.S.C. 5701 *et seq.*, while attending meetings of the Committee or of its subcommittees, or while otherwise performing duties at the request of the chairperson, while away from their homes or a regular place of business.

2. Members of the Committee shall serve as Special Government Employees and are required to file an annual Executive Branch Confidential Financial Disclosure Report.

3. The Committee shall meet at least once per year. Additional meetings may be called whenever the Director of NIST requests a meeting.

4. Committee meetings are open to the public.

*Nomination Information:*

1. Nominations are sought from industry and other communities having an interest in the National Earthquake Hazards Reduction Program, such as, but not limited to, research and academic institutions, industry standards development organizations, state and local government bodies, and financial communities, who are qualified to provide advice on earthquake hazards reduction and represent all related scientific, architectural, and engineering disciplines.

2. Nominees should have established records of distinguished service. The field of expertise that the candidate represents should be specified in the nomination letter. Nominations for a particular field should come from organizations or individuals within that field. A summary of the candidate's qualifications should be included with the nomination, including (where applicable) current or former service on federal advisory boards and federal employment. In addition, each nomination letter should state that the person agrees to the nomination, acknowledges the responsibilities of serving on the Committee, and will actively participate in good faith in the tasks of the Committee.

3. The Department of Commerce is committed to equal opportunity in the workplace and seeks a broad-based and diverse Committee membership.

**Visiting Committee on Advanced Technology (VCAT)**

*Addresses:* Please submit nominations to Janet Brumby, Visiting Committee on Advanced Technology, National Institute of Standards and Technology, 100 Bureau Drive, Mail Stop 1710, Gaithersburg, MD 20899–1710. Nominations may also be submitted via Fax to 301–926–8091. Additional information regarding the Committee, including its charter, current membership list, and executive summary may be found on its electronic home page at: *http://www.nistgov/director/vcat/vcat.htm*

*For Further Information Contact:* Janet Brumby, Visiting Committee on Advanced Technology, National Institute of Standards and Technology, 100 Bureau Drive, Mail Stop 1710, Gaithersburg, MD 20899–1710, telephone 301–975–3189, fax 301–926–8091; or via e-mail at *janet.brumby@nist.gov.*

*Committee Information:* The VCAT was established in accordance with 15 U.S.C. 278 and the Federal Advisory Committee Act (5 U.S.C. App. 2).

*Objectives and Duties*

1. The Committee shall review and make recommendations regarding general policy for NIST, its organization, its budget, and its programs, within the framework of applicable national policies as set forth by the President and the Congress.

2. The Committee functions solely as an advisory body, in accordance with the provisions of the Federal Advisory Committee Act.

3. The Committee shall report to the Director of NIST.

4. The Committee shall provide a written annual report, through the Director of NIST, to the Secretary of Commerce for submission to the Congress on or before January 31 of each year. Such report shall deal essentially, though not necessarily exclusively, with policy issues or matters which affect the Institute, or with which the Committee in its official role as the private sector policy advisor of the Institute is concerned. Each such report shall identify areas of research and research techniques of the Institute of potential importance to the long-term competitiveness of the United States industry, which could be used to assist the United States enterprises and United States industrial joint research and development ventures. The Committee shall submit to the Secretary and Congress such additional reports on specific policy matters as it deems appropriate.

*Membership*

1. The Committee is composed of fifteen members that provide representation of a cross-section of traditional and emerging United States industries. Members shall be selected solely on the basis of established records of distinguished service and shall be eminent in one or more fields such as business, research, new product development, engineering, labor, education, management consulting, environment, and international relations. No employee of the Federal Government shall serve as a member of the Committee.

2. The Director of the National Institute of Standards and Technology shall appoint the members of the Committee, and they will be selected on a clear, standardized basis, in accordance with applicable Department of Commerce guidance.

*Miscellaneous*

1. Members of the VCAT are not paid for their service, but will, upon request, be allowed travel expenses in accordance with 5 U.S.C. 5701 *et seq.*, while attending meetings of the Committee or of its subcommittees, or while otherwise performing duties at the request of the chairperson, while away from their homes or a regular place of business.

2. Meetings of the VCAT take place at the NIST headquarters in Gaithersburg, Maryland, and once each year at the NIST offices in Boulder, Colorado. Meetings are one or two days in duration and are held quarterly.

3. Committee meetings are open to the public.

*Nomination Information:*

1. Nominations are sought from all fields described above.

2. Nominees should have established records of distinguished service and shall be eminent in fields such as business, research, new product development, engineering, labor, education, management consulting, environment and international relations. The category (field of eminence) for which the candidate is qualified should be specified in the nomination letter. Nominations for a particular category should come from organizations or individuals within that category. A summary of the candidate's qualifications should be included with the nomination, including (where applicable) current or former service on federal advisory boards and federal employment. In addition, each nomination letter should state that the person agrees to the nomination, acknowledges the responsibilities of serving on the VCAT, and will actively participate in good faith in the tasks of the VCAT. Besides participation in two-day meetings held each quarter, it is desired that members be able to devote the equivalent of two days between meetings to either developing or researching topics of potential interest, and so forth in furtherance of the Committee duties.

3. The Department of Commerce is committed to equal opportunity in the workplace and seeks a broad-based and diverse VCAT membership.

Dated: July 16, 2007.

**James M. Turner,**

*Deputy Director.*

[FR Doc. 07–3548 Filed 7–19–07; 8:45 am]

BILLING CODE 3510–13–M

---

## DEPARTMENT OF COMMERCE

### National Oceanic and Atmospheric Administration

**RIN 0648–XB49**

### U.S. Climate Change Science Program Synthesis and Assessment Product Draft Report 4.6

**AGENCY:** National Oceanic and Atmospheric Administration (NOAA), Department of Commerce.

**ACTION:** Notice of availability and request for public comments.

**SUMMARY:** The National Oceanic and Atmospheric Administration publish this notice to announce the availability for public comments of the draft Report for one of the U.S. Climate Change Science Program (CCSP) Synthesis and Assessment Products (SAP). This draft Report of SAP 4.6 addresses the following CCSP Topic: ''Analyses of the Effects of Global Change on Human Health, Welfare, and Human Systems'' and analyzes the effects of global change, especially the effects of climate variability and change, along with the associated impacts of land use and population dynamics on three broad dimensions of the human condition: human health, human settlements, and human welfare. After consideration of comments received, a revised Report along with the comments received will be published on the CCSP web site.

**DATES:** Comments must be received by September 4, 2007.

**ADDRESSES:** The draft Report is posted on the SAP 4.6 webpage of the CCSP Program Office web site. The web address to access the draft Report is:*www.climatescience.gov/Library/sap/sap4–6/default.php*

Detailed instructions for making comments on the draft Report are provided on the SAP 4.6 webpage (see link here). Comments should be prepared in accordance with these instructions.

**FOR FURTHER INFORMATION CONTACT:** Dr. Fabien Laurier, Climate Change Science Program Office, 1717 Pennsylvania Avenue NW, Suite 250, Washington, DC 20006, Telephone: (202) 419 3481.

**SUPPLEMENTARY INFORMATION:** The CCSP was established by the President in 2002 to coordinate and integrate scientific research on global change and climate change sponsored by 13 participating departments and agencies of the U.S. Government. The CCSP is charged with preparing information resources that support climate-related discussions and decisions, including scientific synthesis and assessment analyses that support evaluation of important policy issues. SAP 4.6 addresses the affects of global change on human health, human welfare, and human settlements, and is designed to serve decision makers interested in using science to inform adaptations to the impacts of climate variability and change.

Dated: July 16, 2007.

**William J. Brennan,**

*Deputy Assistant Secretary of Commerce for International Affairs, and Acting Director, Climate Change Science Program.*

[FR Doc. E7–14091 Filed 7–19–07; 8:45 am]

**BILLING CODE 3510–12–S**

## DEPARTMENT OF COMMERCE

### National Telecommunications and Information Administration

### Digital-to-Analog Converter Box Coupon Program Public Meeting

**AGENCY:** National Telecommunications and Information Administration (NTIA), U.S. Department of Commerce

**ACTION:** Notice of Public Meeting

**SUMMARY:** NTIA will hold a public meeting on September 25, 2007, in connection with its Digital-to-Analog Converter Box Coupon Program described in the Final Rule that was released on March 12, 2007.

**DATES:** The meeting will be held on September 25, 2007, from 9 a.m. to 1 p.m., Eastern Standard Time.

**ADDRESSES:** The meeting will be held at the U.S. Department of Commerce, National Telecommunications and Information Administration, 1401 Constitution Avenue, NW., Auditorium, Washington, DC (Please enter at 14th Street). The handicapped accessible entrance is located at the 14th Street Aquarium Entrance.

**FOR FURTHER INFORMATION CONTACT:** Francine Jefferson, Consumer Education Manager, at (202) 482–5560.

**SUPPLEMENTARY INFORMATION:** NTIA will host a public meeting to discuss progress in educating the public about the Digital-to-Analog Converter Box Coupon Program. Detailed information about the Coupon Program is available at *http://www.ntia.doc.gov/dtvcoupon.*

Public attendance at the meeting is limited to space available. The meeting will be physically accessible to people with disabilities. Individuals requiring special services, such as sign language interpretation or other ancillary aids, are asked to indicate this to Francine Jefferson at least two (2) days prior to the meeting. Members of the public will have an opportunity to ask questions at the meeting. The meeting will be recorded, and a transcript will be made available on NTIA's website. Individuals who would like to submit questions in writing should e-mail their questions to Francine Jefferson at: *fjefferson@ntia.doc.gov.*

Dated: July 16, 2007.

**Kathy D. Smith,**

*Chief Counsel, National Telecommunications and Information Administration.*

[FR Doc. E7–14021 Filed 7–19–07; 8:45 am]

**BILLING CODE 3510–60–S**

## DEPARTMENT OF DEFENSE

### Office of the Secretary

**[No. DoD–2007–OS–0074]**

### Proposed Collection; Comment Request

**AGENCY:** Defense Finance and Accounting Service, DoD.

**ACTION:** Notice.

**SUMMARY:** In compliance with Section 3506(c)(2)(A) of the Paperwork Reduction Act of 1995, the Defense Finance and Accounting Service announces the proposed extension of a public information collection and seeks public comment on the provisions thereof. 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 information collection; (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.

**DATES:** Consideration will be given to all comments received by September 18, 2007.

**ADDRESSES:** You may submit comments, identified by docket number and title, by any of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the instructions for submitting comments.
- *Mail:* Federal Docket Management System Office, 1160 Defense Pentagon, Washington, DC 20301–1160.
- *Instructions:* All submissions received must include the agency name, docket number and title for this **Federal Register** document. The general policy for comments and other submissions from members of the public is to make these submissions available for public viewing on the Internet at *http://www.regulations.gov* as they are received without change, including any personal identifiers or contact information.

**FOR FURTHER INFORMATION CONTACT:** To request more information on this proposed information collection or to obtain a copy of the proposal and associated collection instruments, please write to the Defense Finance and Accounting Service, ATTN: Vicki Clay, 8899 E. 56th Street, Indianapolis, IN 46249, or call Vicki Clay at 317–510–3802.

*Title and OMB number:* Customer Satisfaction Surveys—Generic Clearance; OMB Number 0730–0003.

*Needs and uses:* The information collection requirement is necessary to determine the kind and quality of services DFAS customers want and expect, as well as their satisfaction with DFAS' existing services.

*Affected public:* Individuals or households, businesses or other for-profit, not-for-profit institutions, Federal Government, and state, local or tribal governments.

*Annual burden hours:* Estimated 6,000.

*Number of respondents:* Estimated 166,000.

*Responses per respondent:* 1.

*Average burden per response:* 2 minutes.

*Frequency:* Annually.

**SUPPLEMENTARY INFORMATION:**

### Summary of Information Collection

DFAS will conduct a variety of activities, including but not necessarily limited to customer, satisfaction surveys and transaction-based telephone interviews. If the customer feedback activities were not conducted, DFAS would not only be in violation of E.O. 12862, but would also not have the knowledge necessary to provide the best service possible and provide unfiltered feedback from the customer for process improvement activities. The information collected provides information about customer perceptions and can help identify agency operations that need quality improvement, provide early detection of process or systems problems, and focus attention on areas where customer service and functional training or changes in existing operations will improve service delivery.

Dated: July 12, 2007.

**Patricia L. Toppings,**

*Alternate OSD Federal Register Liaison Officer, Department of Defense.*

[FR Doc. 07–3532 Filed 7–19–07; 8:45 am]

**BILLING CODE 5001–06–M**

## DEPARTMENT OF DEFENSE

### Office of the Secretary

### Base Closure and Realignment

**AGENCY:** Office of Economic Adjustment, Department of Defense.

**ACTION:** Notice.

**SUMMARY:** This Notice is provided pursuant to section 2905(b)(7)(B)(ii) of the Defense Base Closure and Realignment Act of 1990. It provides a partial list of military installations closing or realigning pursuant to the 2005 Defense Base Closure and Realignment (BRAC) Report. It also provides a corresponding listing of the Local Redevelopment Authorities (LRAs) recognized by the Secretary of Defense, acting through the Department of Defense Office of Economic Adjustment (OEA), as well as the points of contact, addresses, and telephone numbers for the LRAs for those installations. Representatives of state and local governments, homeless providers, and other parties interested in the redevelopment of an installation should contact the person or organization listed. The following information will also be published simultaneously in a newspaper of general circulation in the area of each installation. There will be additional Notices providing this same information about LRAs for other closing or realigning installations where surplus government property is available as those LRAs are recognized by the OEA.

**EFFECTIVE DATE:** July 20, 2007.

**FOR FURTHER INFORMATION CONTACT:** Director, Office of Economic Adjustment, Office of the Secretary of Defense, 400 Army Navy Drive, Suite 200, Arlington, VA 22202–4704, (703) 604–6020.

### Local Redevelopment Authorities (LRAs) for Closing and Realigning Military Installations

*Arkansas*

*Installation Name:* Camden USARC.

*LRA Name:* Camden Airport Commission.

*Point of Contact:* Kathy Lee, Assistant Mayor, City of Camden.

*Address:* P.O. Box 278, 206 Van Buren, N.E., Camden, AR 71701–0278.

*Phone:* (870) 836–6436.

*Wisconsin*

*Installation Name:* Truman Olson USARC.

*LRA Name:* Community Development Authority of the City of Madison.

*Point of Contact:* Mark A. Olinger, Director, Department of Planning & Community & Economic Development, City of Madison.

*Address:* 215 Martin Luther King, Jr. Boulevard, Suite LL100, P.O. Box 2985, Madison, WI 53701–2985.

*Phone:* (608) 266–4635.

Dated: June 16, 2007.

**L.M. Bynum,**

*Alternate OSD Federal Register Liaison Officer, Department of Defense.*

[FR Doc. 07–3535 Filed 7–19–07; 8:45 am]

**BILLING CODE 5001–06–M**

## DEPARTMENT OF DEFENSE

### Department of the Army

### Notice of Availability of the Draft Environmental Impact Statement (DEIS) for the Permanent Stationing of the 2nd Brigade, 25th Infantry Division Stryker Brigade Combat Team (SBCT)

**AGENCY:** Department of the Army, DoD.

**ACTION:** Notice of Availability (NOA).

**SUMMARY:** The Department of the Army announces the availability of a DEIS for the permanent stationing of the 2nd Brigade, 25th Infantry Division (2/25th) SBCT. Pursuant to the National Environmental Policy Act (NEPA), the Department of the Army has prepared this DEIS to disclose potential impacts to the natural, physical, and human environment resulting from the permanent stationing of the 2/25th SBCT. Potential impacts have been analyzed at installations which are capable of meeting the SBCTs training, operational, Soldier and Family quality of life, and strategic deployment requirements.

**DATES:** Written comments on the DEIS will be accepted for 45 days following publication of a notice of availability in the **Federal Register** by the U.S. Environmental Protection Agency.

**ADDRESSES:** Send all written comments and suggestions concerning this EIS to: Public Affairs Office, U.S. Army Environmental Command, Building E4460, Attention: IMAE–PA, 5179 Hoadley Road, Aberdeen Proving Ground, MD 21010–5401. Comments may also be sent via e-mail to *PublicComments@aec.apgea.army.mil.*

**FOR FURTHER INFORMATION CONTACT:** Public Affairs Office at (410) 436–2556; facsimile at (410) 436–1693 (during normal business hours Monday through Friday).

**SUPPLEMENTARY INFORMATION:** The Proposed Action and analysis within the DEIS covers those activities required to implement the stationing of the 2/25th SBCT. These activities include garrison construction, training range construction, live-fire training, and maneuver training.

In May 2004, the Army released the Final Environmental Impact Statement (FEIS) for Transformation of the 2nd Brigade, 25th Infantry Division (Light) to the 2/25th SBCT. The SBCT is a maneuver brigade that includes approximately 4,000 Soldiers (infantry, artillery, engineers, and other Army specialties) and 1,000 vehicles (including about 320 Stryker Combat Vehicles). In July 2004, the Army released a Record of Decision (ROD) documenting its decision to transform the 2/25th from an Infantry brigade to an SBCT and permanently home station it in Hawaii.

The Stryker is an armored infantry wheeled combat vehicle. The Stryker provides Soldiers and commanders with increased firepower, maneuverability, and, most importantly, survivability in a combat environment. The increased speed and maneuver capabilities of the SBCT allow it to conduct operations across much larger areas than the Army's traditional legacy brigades. These capabilities have allowed the SBCT to successfully conduct a broad range of missions in support of Operation Iraqi Freedom.

To be effective when operationally deployed abroad requires that the SBCT have the proper training and support facilities at a home station. Such facilities include training ranges, maneuver land, housing, administrative, and quality of life infrastructure for the SBCTs Soldiers, their Families, vehicles and equipment. Without these resources, the SBCT cannot attain the readiness levels needed to ensure the successful accomplishment of its missions and safety of its Soldiers. In addition to these requirements, the SBCT must be stationed in a location from which it can rapidly deploy to support national security requirements.

The 2/25th began its transformation to an SBCT shortly after completion of the 2004 FEIS and signing of the ROD. As of November 2006, the Brigade had completed a majority of its training and equipment fielding in Hawaii and is scheduled to complete its transformation in 2007. By November 2007, the Army requires that the SBCT be ready for deployment to support ongoing operations.

In October 2006, the Federal Court of Appeals for the Ninth Circuit determined that the Army had not fully complied with NEPA for the transformation of the 2/25th because it did not adequately address or analyze potentially reasonable alternate locations for the transformation and training of this unit. In particular, the Court concluded that the Army had a duty under NEPA to consider locations other than Hawaii for the permanent stationing of the 2/25th SBCT, and the Court ordered the Army to prepare an EIS to address a broader range of alternatives. The Army has prepared an EIS in accordance with the Court's guidance to examine reasonable alternative locations for the proposed action to permanently station the 2/25th SBCT.

The EIS examines several Army installations capable of supporting the permanent stationing of the 2/25th SBCT. The EIS will provide the Army senior leadership with a hard look at environmental impacts associated with the Proposed Action and better inform their decision-making process for selecting the final stationing location. This effort includes analysis of all activities (training, facilities construction, and Soldier and Family support) required to permanently station the 2/25th. This EIS effort will assist the Army in arriving at a decision that can accommodate the Brigade's training, operations, and quality of life requirements while meeting the strategic defense needs of the nation.

After reviewing the full range of potential Army stationing locations, three alternatives for implementing the proposed action have been identified by the Army as reasonable alternatives capable of meeting the Army's need criteria and screening criteria. Alternatives for the proposed action include: (1) Permanently stationing the 2/25th SBCT at Schofield Barracks Military Reservation (SBMR) while conducting required training at military training sites in Hawaii; (2) permanently stationing the 2/25th SBCT at Fort Richardson while conducting required training at military training sites in Alaska; and (3) permanently stationing the 2/25th SBCT at Fort Carson while conducting required training at military training sites in Colorado. In addition to these alternatives, the no action alternative is described and its environmental impacts fully assessed and considered.

Direct, indirect, and cumulative impacts of the Proposed Action have been considered in the DEIS. The DEIS identifies significant impacts at each of the three alternative locations which would occur as a result of implementing the proposed action. Impacts at alternative sites would result from construction and training activities. Significant impacts to resources would be direct and long term. The No Action Alternative provides the baseline conditions for comparison to the Proposed Alternative. Additional concerns or impacts may be identified as a result of comments received on this DEIS.

The Army invites full public participation to promote open communication and better decision making. All persons and organizations that have an interest in the permanent stationing of the 2/25th SBCT are urged to participate in this NEPA evaluation process. Assistance will be provided upon request to anyone having difficulty understanding how to participate. Public meetings will be held in Hawaii, Alaska, and Colorado. The locations, times, and dates of the public hearing will be announced in advance through notices and media news releases.

Dated: July 13, 2007.

**Addison D. Davis, IV,**

*Deputy Assistant Secretary of the Army, (Environment, Safety and Occupational Health).*

[FR Doc. 07–3530 Filed 7–19–07; 8:45 am]

BILLING CODE 3710–08–M

---

## DEPARTMENT OF DEFENSE

### Department of the Army

### Intent To Grant an Exclusive License of a U.S. Government-Owned Patent

**AGENCY:** Department of the Army, DoD.

**ACTION:** Notice.

**SUMMARY:** In accordance with 35 U.S.C. 209 and 37 CFR 404.7(a)(1)(i), announcement is made of the intent to grant an exclusive, royalty-bearing, revocable license within the geographic area of the United States of America and its territories and possessions to U.S. Patent application 11/229,425, filed September 16, 2005 entitled ''Artillery Rocket Trajectory Correction Kit,'' to Diehl BGT Defense GmbH & Co. KG with its principal place of business at Massberg Facility Alte Nussdorfer Strausse 13 88662 Uberlingen, Germany.

**ADDRESSES:** Commander, U.S. Army Research Development and Engineering Command, ATTN: AMSRD–AMR–AS–PT–TR, Bldg. 5400, Redstone Arsenal, AL 35898–5000.

**FOR FURTHER INFORMATION CONTACT:** Dr. Russ Alexander, Officer of Research & Technology Applications, (256) 876–8743.

**SUPPLEMENTARY INFORMATION:** The Artillery Rocket Trajectory Correction Kit (TCK) is a completely self-contained retrofit kit that is externally and fixedly mounted as an add-on to the rear (aft of the tailfins) of an existing, unguided rocket. The TCK continuously measures the pitch and yaw of the rocket during the initial seconds of the flight as it is released from the launch tube. A trajectory correction is calculated to allow the rocket to stay on a desired path. Selected thrusters are then activated to make any necessary flight correction. The thrusters are positioned around the circumference of the rocket body so as to correctively steer the rocket. Thus, rocket accuracy is improved and collateral damage is reduced.

**Brenda S. Bowen,**

*Army Federal Register Liaison Officer.*

[FR Doc. 07–3537 Filed 7–19–07; 8:45 am]

BILLING CODE 3710–08–M

---

## DEPARTMENT OF DEFENSE

### Department of the Army; Corps of Engineers

### Public Hearing and Notice of Availability for the Draft Environmental Impact Statement for the Matagorda Ship Channel Improvement Project, Calhoun County and Matagorda County, TX

**AGENCY:** Department of the Army, U.S. Army Corps of Engineers, DoD.

**ACTION:** Extension of comment period and rescheduling of Public Hearing.

**SUMMARY:** The Notice of Availability for the Draft Environmental Impact Statement (DEIS) published in the **Federal Register** on Friday, May 18, 2007 (72 FR 28032), required comments be submitted on or before July 2, 2007. An editorial correction of the Notice document was published in the **Federal Register** on Thursday, June 2, 2007 (72 FR 31660). The comment period has been extended to September 4, 2007. Additionally, the June 5, 2007, Public Hearing on the proposed project has been rescheduled to August 9, 2007, at the Bauer Community Center, 2300 North Highway 35, Port Lavaca, TX 77979. Poster presentations will be available for viewing and project team members will be present to discuss the

DEIS at a Workshop that will precede the Public Hearing. The Workshop will be conducted from 5 p.m. to 6:45 p.m. and the formal Public Hearing will comment at 7 p.m.

**FOR FURTHER INFORMATION CONTACT:** Ms. Denise Sloan, Regulatory Project Manager, U.S. Army Corps of Engineers, Galveston District, P.O. Box 1229, Galveston, TX 77553–1229, (409) 766–3962.

**Brenda S. Bowen,**

*Army Federal Register Liaison Officer.*

[FR Doc. 07–3536 Filed 7–19–07; 8:45 am]

BILLING CODE 3710–52–M

---

## DEPARTMENT OF DEFENSE

### Department of the Army; Corps of Engineers

### Intent To Prepare a Draft Environmental Impact Statement/Environmental Impact Report (DEIS/EIR) for the San Jacinto River, Riverside County, CA

**AGENCY:** Department of the Army, U.S. Army Corps of Engineers, DoD.

**ACTION:** Notice of intent.

**SUMMARY:** The purpose of the study is to evaluate approximately a 2-mile reach of the San Jacinto River located in Riverside County in the City of San Jacinto, CA. The focus will be on watershed improvements by developing alternatives for ecosystem restoration and incorporating conjunctive uses for groundwater recharge, water quality and water conservation from a mile up from Main Street to a mile past the end of San Jacinto Street. The restoration project will focus on revitalization of the riparian vegetation community; establish environmental corridor to benefit wildlife and sensitive species; increasing recharge of the San Jacinto groundwater basins; and restoring the habitat for the endangered San Bernardino Kangaroo Rat. The San Jacinto River is located about 20 miles southeast of the City of Riverside and is entirely within Riverside County, CA.

**DATES:** Provide comments by August 22, 2007.

**ADDRESSES:** Submit comments to Mrs. Priscilla E. Perry at U.S. Army Corps of Engineers, Los Angeles District, CESPL–PD–RL, P.O. Box 532711, Los Angeles, CA 90053–2325.

**FOR FURTHER INFORMATION CONTACT:** Mrs. Priscilla E. Perry, Chief, Regional Planning, Environmental Engineers, at 213–452–3867, 213–713–2677; Fax 213–452–4204 or e-mail at *Priscilla.e.Perry@usace.army.mil.*

**SUPPLEMENTARY INFORMATION:**

1. *Authorization.* The proposed study is authorized by the Flood Control Act 1936; WRDA 1986, Public Law 99–662: House Resolution dated October 9, 1998, Section 416 of WRDA 2000, which reads as follows:

''San Jacinto River, California.—The Committee has provided $100,000 for the Corps of Engineers to initiate a reconnaissance study to examine flood control, environmental enhancement and related purposes along the San Jacinto River, California, between the City of San Jacinto and the City of Lake Elsinore''.
Section 416 of WRDA 2000:
Section 416. San Jacinto Watershed, California.

(a) In General.—The Secretary shall conduct a watershed study for the San Jacinto watershed, California.

(b) Authorization of Appropriations.—There is authorized to be appropriated to carry out this section $250,000''.

2. *Background.* The construction of the San Jacinto levee project in 1961 proved to be effective in preventing flood damages during the 1969 floods on the San Jacinto River. The February 1980 floods were not any greater than the 1969 floods, but caused the San Jacinto River levee to fail resulting in massive flooding in the City of San Jacinto. The levee was repaired by adding toe stone, groins, and extending the Bautista Creek concrete channel by another 1.3 miles to the confluence with San Jacinto Creek around the late 1984 to early 1985 timeframe. The 2-mile reach of the San Jacinto River which is located a mile up from Main Street to a mile past the end of San Jacinto Street, poses damage to aquatic ecosytems from past flooding and types of anthropogenic activities. Ecosystems processes that help maintain groundwater supplies must be protected and restored where degraded. Increasing groundwater recharge is a way to support the ecosystem and improve the habitat for the endangered San Bernardino Kangaroo Rat. Alternatives to be considered are those that will reduce adverse water quality impacts from runoff; reduce further degradation of the river and the area ecosystem and improve the quality of both ground and surface waters.

3. *Scoping Process.* a. A scoping meeting is scheduled for August 22, 6 p.m.–8 p.m. at Simpson Center—305 E. Devonshire Ave., Hemet, CA 92543.

For specific dates, times and locations please contact Peter Odencrans, Eastern Municipal Water District, at 951–928–3777 or e-mail at: *odencransp@emwd.org.* Potential impacts associated with the proposed action will be evaluated. Resource categories that will be analyzed are: physical environment, geology, biological resources, air quality, water quality, recreational usage, aesthetics, cultural resources, transportation, noise, hazardous waste, socioeconomics and safety.

b. Participation of affected Federal, State and local resource agencies, Native American groups and concerned interest groups/individuals is encouraged in the scoping process. Public participation will be especially important in defining the scope of analysis in the Draft EIS/EIR, identifying significant environmental issues and impact analysis of the Draft EIS/EIR and providing useful information such as published and unpublished data, personal knowledge of relevant issues and recommending mitigation measures associated with the proposed action.

c. Those interested in providing information or data relevant to the environmental or social impacts that should be included or considered in the environmental analysis can furnish this information by writing to the points of contact indicated above or by attending the public scoping meeting. A mailing list will also be established so pertinent data may be distributed to interested parties.

Dated: July 9, 2007.

**Alex C. Dornstauder,**

*Colonel, U.S. Army, District Engineer.*

[FR Doc. 07–3539 Filed 7–19–07; 8:45 am]

BILLING CODE 3710–KF–M

---

## DEPARTMENT OF DEFENSE

### Department of the Navy

### Notice of Availability and Notice of Public Meeting of the Draft Environmental Impact Statement (DEIS) for the Development of the Westside of Marine Corps Base Quantico, Including the 2005 Base Realignment and Closure (BRAC) Action at Marine Corps Base Quantico, Virginia

**AGENCY:** Department of the Navy, Department of Defense.

**ACTION:** Notice of Availability (NOA) and public meeting.

**SUMMARY:** In accordance with Section 102(2)(C) of the National Environmental Policy Act of 1969 (42 U.S.C. 4332(2)(C)), as implemented by the Council on Environmental Quality Regulations (40 CFR parts 1500–1508), the Department of the Navy (DON), and Marine Corps Base Quantico (MCBQ) announces the availability of the DEIS, which evaluates the environmental effects of development of the Westside

of MCBQ to accommodate approximately 3,000 personnel directed to MCBQ by the 2005 BRAC law, and potential development within the Westside to accommodate up to 2,000 additional personnel, or 5,000 personnel total including BRAC, to support other Marine Corps requirements.

**DATES:** The public comment period for the DEIS will end 45 days after publication of an NOA in the **Federal Register** by the Environmental Protection Agency. All comments must be received by 4 September 2007.

**ADDRESSES:** Please send written comments on the DEIS to: Jeff Gardner, NREA Branch (B046), 3250 Catlin Avenue, Marine Corps Base, Quantico, VA 22134–0855. E-mail comments should be sent to *jeff.gardner@usmc.mil*.

**FOR FURTHER INFORMATION CONTACT:** Mr. Jeff Gardner 703–432–6784 during normal business hours Monday through Friday.

**SUPPLEMENTARY INFORMATION:** The Marine Corp Base Quantico, Virginia proposes development of the Westside of MCBQ, including the 2005 Base Realignment and Closure (BRAC) action at MCBQ. The development would entail construction of new facilities in two undeveloped areas west of Interstate 95. These areas, the Russell Road Area and the MCB–1 Area, would co-locate Military Department Investigative Agency Headquarters with the Counterintelligence Field Activity and Defense Security Service at MCBQ as directed by the 2005 BRAC law. The areas would also provide adequate space for facilities to support Marine Corps units currently at MCBQ, as well as potentially other federal and Marine Corps initiatives that may identify MCBQ as a site for relocation.

This DEIS identifies and evaluates the potential environmental impacts of (1) Alternative A (BRAC Action), the relocation of approximately 3,000 personnel directed to MCBQ by the BRAC Law; (2) Alternative B, the relocation of an additional 2,000 personnel for a total of 5,000 personnel, including those under Alternative A; and (3) the No Action Alternative. Under both Alternatives A and B, two sites for the BRAC action, one located in the southern portion of the Russell Road Area, and the other in the northern portion of the MCB–1 Area, are analyzed as the BRAC site options (BRAC Option 1 (Russell Road) and BRAC Option 2 (MCB–1)).

The Notice of Intent (NOI) published for this EIS in the **Federal Register** on 3 August 2006 identified five alternatives, including the no action alternative, for analysis in this EIS. In addition to Alternatives A and B, the NOI indicated that a high intensity development alternative would be assessed that would add up to 10,000 personnel, including 3,000 under BRAC, and a medium intensity development alternative would be assessed that would add up to 7,000 personnel, including 3,000 under BRAC. Following a preliminary assessment of the proposed sites west of I–95 and further examination of known requirements, only Alternatives A and B were carried forward for analysis.

At this time, a preferred alternative has not been selected. The DEIS analysis indicate that the increased level of development and personnel under Alternative B compared to Alternative A would be expected to cause a commensurate increase in the level of impacts.

The DEIS finds that traffic impacts at base access points are similar for both alternatives. Major MCBQ access points currently perform unacceptably and regional growth will further degrade intersections unless improvements are made. Alternatives have unacceptable levels of service at U.S. Route 1 and I–95 intersections, and at proposed development sites. The DEIS identifies traffic mitigation measures.

The DEIS also finds that the amount of development from the proposed alternatives is small compared to the amount of undeveloped land that would remain, largely forested, minimizing impacts to natural resources. There would be no effect to threatened and endangered species; however, alternatives could impact a small amount of wetlands. The DEIS finds that potential regional growth from either alternative is not large compared to projected growth already expected for the surrounding region and the resulting socioeconomic impacts from either alternative are less than significant. Potential impacts, such as noise, caused by proximity to military training activities that would remain in the Westside, can be acceptably minimized in the facility design process, and development is a compatible land use at the proposed sites. The sites avoid impacting cultural resources and air emissions are not expected to exceed the thresholds established for general conformity to state implementation plans or to require a new source review.

The DEIS has been distributed to various federal, state, and local agencies, elected officials, special interest groups, and interested parties. The DEIS is also available for public review at the following local libraries: Central Rappahannock Regional Library, Dumfries Neighborhood Library, and the Prince William Public Library System. The DEIS is also available at the following Web site: *http://www.quantico.usmc.mil/activities/display.aspx?PID=1814&Section=NREA*. The Marine Corps invites the general public, local governments, other federal agencies, and state agencies to submit written comments or suggestions concerning the alternatives and analysis addressed in the DEIS. The public and government agencies are invited to participate in the public meetings where oral and written comments will be received. Two public meetings will be held. The first public meeting will be held on 6 August 2007 from 7:30 p.m. to 9:30 p.m. at the Stafford County Government Center Board Room, 1300 Courthouse Road, Stafford, VA. The second public meeting will be held on 13 August 2007 from 6:30 p.m. to 9:30 p.m. at the Doctor A. J. Ferlazzo Building, 15941 Donald Curtis Drive, Prince William, VA. All comments must be received by 4 September 2007.

Dated: July 16, 2007.

**L.R. Almand,**

*Office of the Judge Advocate General, U.S. Navy, Administrative Law Division, Federal Register Liaison Officer.*

[FR Doc. E7–14126 Filed 7–19–07; 8:45 am]

BILLING CODE 3810–FF–P

## DEPARTMENT OF DEFENSE

### Department of Navy

### Privacy Act of 1974; System of Records

**AGENCY:** Department of the Navy, DoD.

**ACTION:** Notice to delete a System of Records.

**SUMMARY:** The Department of the Navy is deleting a system of records in its existing inventory of record systems subject to the Privacy Act of 1974, (5 U.S.C. 552a), as amended.

**DATES:** This proposed action will be effective without further notice on August 20, 2007 unless comments are received which result in a contrary determination.

**ADDRESSES:** Send comments to the Department of the Navy, PA/FOIA Policy Branch, Chief of Naval Operations (DNS–36), 2000 Navy Pentagon, Washington, DC 20350–2000.

**FOR FURTHER INFORMATION CONTACT:** Mrs. Doris Lama at (202) 685–6545.

**SUPPLEMENTARY INFORMATION:** The Department the Navy systems of records notices subject to the Privacy Act of 1974, (5 U.S.C. 552a), as amended, have been published in the **Federal Register**

and are available from the address above.

The Department of Navy proposes to delete a system of records notice from its inventory of record systems subject to the Privacy Act of 1974 (5 U.S.C. 552a), as amended. The proposed deletion is not within the purview of subsection (r) of the Privacy Act of 1974 (5 U.S.C. 552a), as amended, which requires the submission of new or altered systems reports.

Dated: July 13, 2007.

**C.R. Choate,**

*Alternate OSD Federal Register Liaison Officer, Department of Defense.*

**N12930–2**

**SYSTEM NAME:**

Area Coordinator Information and Operation Files (February 22, 1993, 58 FR 10825).

**REASON:**

Program changed which required the establishment of a new system. The new system is N12713–1, Equal Employment Opportunity (EEO) Complaints Tracking System which was published in the **Federal Register** on May 14, 2007, 72 FR 27094.

[FR Doc. 07–3534 Filed 7–19–07; 8:45 am]

**BILLING CODE 5001–06–M**

## DEPARTMENT OF EDUCATION

### Notice of Proposed Information Collection Requests

**AGENCY:** Department of Education.

**SUMMARY:** The IC Clearance Official, Regulatory Information Management Services, Office of Management, invites comments on the proposed information collection requests as required by the Paperwork Reduction Act of 1995.

**DATES:** Interested persons are invited to submit comments on or before September 18, 2007.

**SUPPLEMENTARY INFORMATION:** Section 3506 of the Paperwork Reduction Act of 1995 (44 U.S.C. Chapter 35) requires that the Office of Management and Budget (OMB) provide interested Federal agencies and the public an early opportunity to comment on information collection requests. OMB may amend or waive the requirement for public consultation to the extent that public participation in the approval process would defeat the purpose of the information collection, violate State or Federal law, or substantially interfere with any agency's ability to perform its statutory obligations. The IC Clearance Official, Regulatory Information Management Services, Office of Management, publishes that notice containing proposed information collection requests prior to submission of these requests to OMB. Each proposed information collection, grouped by office, contains the following: (1) Type of review requested, e.g., new, revision, extension, existing or reinstatement; (2) Title; (3) Summary of the collection; (4) Description of the need for, and proposed use of, the information; (5) Respondents and frequency of collection; and (6) Reporting and/or Recordkeeping burden. OMB invites public comment.

The Department of Education is especially interested in public comment addressing the following issues: (1) Is this collection necessary to the proper functions of the Department; (2) will this information be processed and used in a timely manner; (3) is the estimate of burden accurate; (4) how might the Department enhance the quality, utility, and clarity of the information to be collected; and (5) how might the Department minimize the burden of this collection on the respondents, including through the use of information technology.

Dated: July 16, 2007.

**Angela C. Arrington,**

*IC Clearance Official, Regulatory Information Management Services, Office of Management.*

**Institute of Education Sciences**

*Type of Review:* Revision.

*Title:* National Evaluation of the Comprehensive Technical Assistance Centers.

*Frequency:* One time.

*Affected Public:* State, Local, or Tribal Gov't, SEAs or LEAs.

*Reporting and Recordkeeping Hour Burden:*

*Responses:* 2,124.

*Burden Hours:* 1,709.

*Abstract:* The purpose of this study is to evaluate the Comprehensive Technical Assistance Centers created to assist state education agencies with the implementation of the requirements of No Child Left Behind legislation. Four key methods will be used in this study: (1) Site visits conducted to each Center to learn about the Center's relationships with its clients and the types of products and services that are delivered; (2) expert panel review of a sample of projects undertaken by each Center to assess the quality of the technical assistance provided; (3) a survey of Center clients to rate the relevance, usefulness and other aspects of the services they have received; and (4) a survey of senior SEA officials who are responsible for negotiating with the Centers to ensure that the nature of technical assistance provided corresponds to state priorities.

Requests for copies of the proposed information collection request may be accessed from *http://edicsweb.ed.gov*, by selecting the ''Browse Pending Collections'' link and by clicking on link number 3414. When you access the information collection, click on ''Download Attachments'' to view. Written requests for information should be addressed to U.S. Department of Education, 400 Maryland Avenue, SW., Potomac Center, 9th Floor, Washington, D.C. 20202–4700. Requests may also be electronically mailed to: *ICDocketMgr@ed.gov* or faxed to 202–245–6623. Please specify the complete title of the information collection when making your request.

Comments regarding burden and/or the collection activity requirements should be electronically mailed to: *ICDocketMgr@ed.gov*. Individuals who use a telecommunications device for the deaf (TDD) may call the Federal Information Relay Service (FIRS) at 1–800–877–8339.

[FR Doc. E7–14027 Filed 7–19–07; 8:45 am]

**BILLING CODE 4000–01–P**

## DEPARTMENT OF EDUCATION

### Federal Pell Grant, Academic Competitiveness Grant, National Science and Mathematics Access To Retain Talent Grant, Federal Perkins Loan, Federal Work-Study, Federal Supplemental Educational Opportunity Grant, Federal Family Education Loan, and William D. Ford Federal Direct Loan Programs; Correction

**AGENCY:** Federal Student Aid, U.S. Department of Education.

**ACTION:** Correction; Notice of revision of the Federal Need Analysis Methodology for the 2008–2009 award year.

**SUMMARY:** We correct two column headings for the Education Savings and Asset Protection Allowance tables in the notice published on June 1, 2007 (72 FR 30570).

**SUPPLEMENTARY INFORMATION:** On June 1, 2007, we published a notice in the **Federal Register** (72 FR 30568–30572), Notice of revision of the Federal Need Analysis Methodology for the 2008–2009 award year. The heading ''If the age of the student is'' (as published in the three tables on page 30570) is corrected to read, ''If the age of the older parent is''. This correction should be made only to the first of the three tables, titled ''Dependent Students'' on page 30570. The right column of the same table (Dependent Students) is labeled, ''And they are'', is corrected to read, ''And there are''.

**FOR FURTHER INFORMATION CONTACT:** Ms. Marya Dennis, Management and Program Analyst, U.S. Department of Education, Union Center Plaza, 830 First Street, NE., Washington, DC 20202. Telephone: (202) 377–3385. If you use a telecommunications device for the deaf (TDD), you may call the Federal Relay Service (FRS) at 1–800–877–8339.

Individuals with disabilities may obtain this document in an alternative format (e.g., Braille, large print, audiotape or computer diskette) on request to the contact person listed in the preceding paragraph.

*Electronic Access to This Document:* You may view this document, as well as all other documents of this Department published in the **Federal Register**, in text or Adobe Portable Document Format (PDF) on the Internet at the following site: *http://www.ed.gov/news/fedregister*.

To use PDF you must have Adobe Acrobat Reader, which is available free at this site. If you have questions about using PDF, call the U.S. Government Printing Office (GPO), toll free, at 1–888–293–6498; or in the Washington, DC, area at (202) 512–1530.

**Note:** The official version of this document is the document published in the **Federal Register**. Free Internet access to the official edition of the **Federal Register** and the Code of Federal Regulations is available on GPO Access at: *http://www.gpoaccess.gov/nara/index.html*.

Dated: July 17, 2007.

**Lawrence A. Warder,**

*Acting Chief Operating Officer, Federal Student Aid.*

[FR Doc. E7–14108 Filed 7–19–07; 8:45 am]

**BILLING CODE 4000–01–P**

## DEPARTMENT OF ENERGY

### Office of Science, Department of Energy; Notice of Renewal of the High Energy Physics Advisory Panel

Pursuant to section 14(a)(2)(A) of the Federal Advisory Committee Act, App. 2, and § 102–3.65, title 41, Code of Federal Regulations and following consultation with the Committee Management Secretariat, General Services Administration, notice is hereby given that the High Energy Physics Advisory Panel has been renewed for a two year period, beginning July 14, 2007.

The Panel will provide advice to the Associate Director, for High Energy Physics, Office of Science (DOE), and the Assistant Director, Mathematical & Physical Sciences Directorate (NSF), on long-range planning and priorities in the national high-energy physics program. The Secretary of Energy had determined that renewal of the Panel is essential to conduct business of the Department of Energy and the National Science Foundation and is in the public interest in connection with the performance of duties imposed by law upon the Department of Energy. The Panel will continue to operate in accordance with the provisions of the Federal Advisory Committee Act (Pub. L. 92–463), the General Services Administration Final Rule on Federal Advisory Committee Management, and other directives and instructions issued in implementation of those acts.

*For Further Information Contact:* Ms. Rachel Samuel at (202) 586–3279.

Issued in Washington, DC on July 14, 2007.

**James N. Solit,**

*Advisory Committee Management Officer.*

[FR Doc. E7–14056 Filed 7–19–07; 8:45 am]

**BILLING CODE 6450–01–P**

## ENVIRONMENTAL PROTECTION AGENCY

**[EPA–HQ–OA–2007–0607; FRL–8441–4]**

### Agency Information Collection Activities; Proposed Collection; Comment Request; Performance Measurement Reporting for Training and Education/Outreach; EPA ICR No. 2255.01

**AGENCY:** Environmental Protection Agency.

**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 for a new Information Collection Request (ICR) to the Office of Management and Budget (OMB). 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 September 18, 2007.

**ADDRESSES:** Submit your comments, identified by Docket ID No. EPA–HQ–OA–2007–0607, by one of the following methods:

- *http://www.regulations.gov:* Follow the on-line instructions for submitting comments.
- *E-mail: oei.docket@epa.gov.*
- *Fax:* 202–566–0224.
- *Mail:* Office of Environmental Information (OEI) Docket, Environmental Protection Agency, Mail Code: 2822T, 1200 Pennsylvania Ave., NW., Washington, DC 20460.
- *Hand Delivery:* Office of Environmental Information (OEI) Docket in the EPA Docket Center (EPA/DC), EPA West, Room B102, 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–2007–0607. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *www.regulations.gov* or *e-mail.* The *http://www.regulations.gov* website is an ''anonymous access'' system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through *www.regulations.gov* your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses. For additional information about EPA's public docket visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm.*

**FOR FURTHER INFORMATION CONTACT:** Peggy Anthony, National Policy, Training and Compliance Division, Office of Grants and Debarment, Mail Code: 3903R, Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460; telephone number: 202–564–5364; fax number: 202–565–2468; e-mail address: *anthony.peggy@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–2007–0607, which is available for online viewing at *http://www.regulations.gov,* or in person viewing at the Office of Environmental Information Docket in the EPA Docket Center (EPA/DC), EPA West, Room B102, 1301 Constitution Ave., NW., Washington, DC. The EPA/DC Public Reading Room is open from 8 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 *http://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 include recipients of EPA discretionary/project assistance agreements (i.e., grants and cooperative agreements) that perform training and/or education and outreach.

*Title:* Performance Measurement Reporting for Training and Education/Outreach.

EPA ICR No.: 2255.01.

*ICR status:* This ICR is for a new information collection activity. 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 is developing some generic reporting tools that will supplement the existing performance reports submitted by grant recipients under 40 CFR Parts 30 and 31. The new reporting tools will be designed to collect performance measurement information on two types of activities performed by grantees: Training and education/outreach. Specifically, EPA is creating a ''master list'' of generic questions and reporting templates, and will make them available to the EPA programs and grant recipients (e.g., on the EPA web site). The questions will be designed to measure the extent to which the grantees are achieving the short-term and intermediate outcomes stated in their work plans for training and/or education/outreach (e.g., the questions will measure changes in trainees' awareness, understanding, and potential or actual changes in behavior). The questions and templates will be flexible enough for use by any of the EPA programs. A grant recipient could review the master list, select the questions appropriate for its needs, and assemble them onto a reporting template. After receiving approval to use the collection instrument, the grant recipient could provide the instrument to its training participants or other audience members to complete. The grantee could then collect, summarize, and report the data to EPA. These reporting tools will be intended specifically for use under the Agency's discretionary/project grants. Use of the forms will not be required, but used at the discretion of the responsible program.

EPA intends to create a generic ICR that would address its reporting tools. Upon OMB approval of the generic ICR, EPA program offices and their grant recipients would be able to modify the forms narrowly for their specific needs and re-submit the revised instruments and supporting material for expedited OMB approval encompassing a 20-day turn-around timeframe.

*Burden Statement:* The annual public reporting and recordkeeping burden for this collection of information is estimated to range from five minutes to 1.5 hours 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 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 average annual number of grants affected:* between 240 and 480.

*Estimated annual frequency of response:* Quarterly or less often.

*Estimated annual average number of responses for each grant:* 4.

*Estimated total annual respondent burden hours:* 12,820 hours.

*Estimated total annual respondent costs:* $359,149. This includes an estimated labor cost of $359,149 and $0 for capital investment or maintenance and operational costs.

**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: July 13, 2007.

**Kathleen Herrin,**

*Acting Director of the Office of Grants and Debarment.*

[FR Doc. E7–14064 Filed 7–19–07; 8:45 am]

**BILLING CODE 6560–50–P**

---

## ENVIRONMENTAL PROTECTION AGENCY

**[ER–FRL–6689–2]**

### Environmental Impact Statements and Regulations; Availability of EPA Comments

Availability of EPA comments prepared pursuant to the Environmental Review Process (ERP), under section 309 of the Clean Air Act and Section 102(2)(c) of the National Environmental Policy Act as amended. Requests for copies of EPA comments can be directed to the Office of Federal Activities at 202–564–7167.

An explanation of the ratings assigned to draft environmental impact statements (EISs) was published in FR dated April 6, 2007 (72 FR 17156).

**Draft EISs**

*EIS No. 20070042, ERP No. D–BLM–K09809–CA,* Truckhaven Geothermal Leasing Area, Addresses Leasing of Geothermal Resources, El Centro Field Office, Imperial County, CA.

*Summary:* EPA expressed environmental concerns about impacts on air quality, water resources, habitat, and recreational use in the OWSVRA. Additionally, EPA is concerned that the geothermal resources within the Truckhaven GLA may be underestimated, and that cumulative impacts associated with multiple geothermal projects on private and public land have not been analyzed. Rating EC2.

*EIS No. 20070061, ERP No. D–BLM–K09810–CA,* Mountain View IV Wind Energy Project, Construction and Operation, Wind Turbine Generators on Public Lands in Section 22 and 28 and Private Land Section 27, Right-of-Way Grant and Conditional Use Permit in the City of Palm Springs, CA .

*Summary:* EPA does not object to the project as proposed, but suggests incorporating additional mitigation measures to minimize air quality impacts during construction. Rating LO.

*EIS No. 20070065, ERP No. D–BLM–K65326–CA,* Eastern San Diego County Resource Management Plan, Implementation, San Diego County, CA.

*Summary:* EPA is supportive of an alternative that balances ecological and economic needs; however, the final EIS should include additional information on air and water quality impacts, existing ecological conditions, and future monitoring plans. Rating EC2.

*EIS No. 20070068, ERP No. D–BLM–K65327–AZ,* Ironwood Forest National Monument, Resource Management Plan, Implementation, Tucson Field Office, AZ.

*Summary:* EPA expressed environmental concerns about environmental impacts from off-highway vehicles (OHV), livestock grazing, and mining, and recommends restricting OHV use and implementing a biological monitoring and adaptive management plan. Rating EC2.

*EIS No. 20070083, ERP No. D–SFW–K39015–CA,* PROGRAMMATIC—South Bay Salt Pond Restoration Project, Restored Tidal Marsh, Managed Ponds, Flood Control Measures and Public Access Features, Don Edward San Francisco Bay National Wildlife Refuge, Alameda, Santa Clara and San Mateo Counties, CA.

*Summary:* EPA expressed environmental concerns about the programmatic approach taken by USFWS for the related shoreline study which exceeds the geographic scope of the salt ponds restoration project. EPA also expressed concerns about construction and operational emissions. Rating EC2.

*EIS No. 20070096, ERP No. D–USA–D15000–MD,* Garrison Aberdeen Proving Ground, Base Realignment and Closure Actions, Realignment of Assets and Staff, Implementation, Harford and Baltimore Counties, MD.

*Summary:* EPA expressed environmental concern about potential impacts to natural resources. EPA stated that this project also presents an excellent opportunity to implement the President's Executive Order 13423, Strengthening Federal Environmental, Energy and transportation management by incorporating energy efficiency into the retrofit or construction efforts for this project. Rating EC2.

*EIS No. 20070049, ERP No. DA–FTA–K40208–CA,* South Sacramento Corridor Phase 2, Improve Transit Service and Enhance Regional Connectivity, Funding, in the City and County Sacramento, CA.

*Summary:* EPA does not object to the proposed project. Rating LO.

*EIS No. 20070075, ERP No. DS–APH–A99222–00,* Importation of Solid Wood Packing Material, To Re-evaluate and Refine Estimates of Methyl Bromide Usage in the Treatment, Implementation, United States.

*Summary:* EPA does not object to the proposed action. Rating LO.

*EIS No. 20070112, ERP No. DS–SFW–K99034–CA,* Coachella Valley, Revision to the Multiple Species Habitat Conservation Plan (MSHCP), Natural Community Conservation Plan, Santa Rosa and San Jacinto Mountains Trails Plan, Issuance of Incidental Take Permit, Riverside County, CA.

*Summary:* No formal letter was sent to the preparing agency. Rating NC.

**Final EISs**

*EIS No. 20070059, ERP No. F–NPS–K39094–NV,* Clean Water Coalition Systems Conveyance and Operations Program, (SCOP) Construction, Operation and Maintenance, Boulder Islands North is the Selected Alternative, City of Las Vegas, NV.

*Summary:* No formal comment letter was sent to the preparing agency.

*EIS No. 20070125, ERP No. F–NPS–K65082–AZ,* Walnut Canyon National Monument, General Management Plan, Implementation, Flagstaff Area, Coconina County, AZ.

*Summary:* No formal letter was sent to the preparing agency.

*EIS No. 20070136, ERP No. F–COE–K39100–CA,* Hemet/San Jacinto Integrated Recharge and Recovery Program, Construction and Operation, US Army COE Section 404 Permit, Riverside County, CA.

*Summary:* The final EIS has addressed many of EPA's earlier concerns; however, EPA continues to express concerns about impacts to waters of the U.S. and provided several recommendations for inclusion in the Record of Decision to address those impacts.

*EIS No. 20070139, ERP No. F–MMS–A02245–00,* Gulf of Mexico Outer Continental Shelf Oil and Gas. Lease Sales: 2007–2012 Western Planning Area Sales 204, 207, 210, 215, and 218: Central Planning Area Sales 205, 206, 208, 213, 216, and 222, TX, LA, MS, AL and FL.

*Summary:* No formal comment letter was sent to the preparing agency.

*EIS No. 20070146, ERP No. F–COE–K36147–CA,* ADOPTION—Folsom Dam Safety and Flood Damage Reduction Project, Addressing Hydrologic, Seismic, Static, and Flood Management Issues, Sacramento, El Dorado and Placer Counties, CA.

*Summary:* EPA continues to express environmental concern about potential water quality impacts from future actions associated with this project.

*EIS No. 20070182, ERP No. F–COE–D35062–MD,* Masonville Dredged Material Containment Facility, New Information, New Source of Dike Building Material from the Seagirt Dredging Project within the Patapsco River, Funding, Baltimore, MD.

*Summary:* EPA's previous concerns have been resolved; therefore, EPA does not object to the proposed action.

*EIS No. 20070183, ERP No. F–FHW–K40259–CA,* Big Bear Lake Bridge Replacement Project, near Big Bear Lake on CA–18 from Kilopost 71.1/71.9, Realignment and Widening Roadways, U.S. COE Section 404 Permit, Funding, San Bernardino National Forest, San Bernardino County, CA.

*Summary:* No formal letter was sent to the preparing agency.

*EIS No. 20070189, ERP No. F–NRS–D36122–WV,* Dunloup Creek Watershed Plan, Voluntary Floodplain Buyout, Implementation, West Virginia Third Congressional District, Fayette and Raleigh Counties, WV.

*Summary:* EPA does not object to the proposed action.

*EIS No. 20070179, ERP No. FS–AFS–L65509–WA,* School Fire Salvage Recovery Project, To Clarify Definitions of Live and Dead Trees, Implementation, Pomeroy Ranger District, Umatilla National Forest, Columbia and Garfield Counties, WA.

*Summary:* EPA does not object to the proposed action; however, EPA supports the monitoring of the survival of fire-damaged trees across the project area (both inside and outside of sale units), to validate the predicted outcomes.

Dated: July 17, 2007.

**Robert W. Hargrove,**

*Director, NEPA Compliance Division, Office of Federal Activities.*

[FR Doc. E7–14107 Filed 7–19–07; 8:45 am]

**BILLING CODE 6560–50–P**

---

## ENVIRONMENTAL PROTECTION AGENCY

**[ER–FRL–6689–1]**

## Environmental Impacts Statements; Notice of Availability

*Responsible Agency:* Office of Federal Activities, General Information (202) 564–7167 or *http://www.epa.gov/compliance/nepa/*.

Weekly receipt of Environmental Impact Statements

Filed 07/09/2007 Through 07/13/2007 Pursuant to 40 CFR 1506.9.

*EIS No. 20070295, Draft EIS, AFS, CO*, Hunter Reservoir Enlargement Project, Reconstruction and Enlargement, Ute Water Conservancy District, U.S. Army COE Section 404 Permit, Grand Mesa National Forest, Mesa County, CO, Comment Period Ends: 09/04/2007, Contact: Carrie Suber 970–242–8211.

*EIS No. 20070296, Draft EIS, AFS, CA*, Eldorado National Forest Public Wheeled Motorized Travel Management Project, Proposes to Regulate Unmanaged Public Wheeled Motor Vehicle, Implementation, Alphine, Amador, El Dorado and Placer Counties, CA, Comment Period Ends: 09/04/2007, Contact: Laura Hierholzer 530–642–5187.

*EIS No. 20070297, Draft EIS, AFS, UT*, Big Creek Vegetation Treatment Project, To Treat 4,800 Acres of Aspen Conifer and Sagebrush Communities, Ogden Ranger District, Wasatch-Cache National Forest, Rich County, UT, Comment Period Ends: 09/04/2007, Contact: Chip Sibbernsen 801–625–5112.

*EIS No. 20070298, Draft EIS, AFS, UT*, Millville Peak/Logan Peak Road Relocation Project, Provide a Safe, Reliable, Ground Access Route, Logan Ranger District, Wasatch-Cache National Forest, Cache County, UT, Comment Period Ends: 09/04/2007, Contact: Evelyn Sibbernsen 435–755–3620.

*EIS No. 20070299, Draft EIS, AFS, WY*, Battle Park Cattle and Horse (C&H) and Mistymoon Sheep and Goat (S&G) Allotment Project, Proposes to Continue Livestock Grazing on both Allotments, Powder River District Ranger, Bighorn National Forest, Bighorn County, WY, Comment Period Ends: 09/04/2007, Contact: Mark Booth 303–684–7806.

*EIS No. 20070300, Legislative Draft EIS, USA, MT*, Limestone Hills Training Area (LHTA) Withdrawal Project, To Withdraw Federal Lands from within the LHTA from DOI, Bureau of Land Management for Transfer to Montana Army National Guard for Military Training Use, Broadwater County, MT, Comment Period Ends: 10/19/2007 Contact: Patrick Magnotta 703–607–7982.

*EIS No. 20070301, Legislative Draft EIS, COE, LA*, Mississippi River—Gulf Outlet (MRGO) Deep-Draft Navigation De-Authorization Study, Implementation, St. Bernard Parish, LA, Comment Period Ends: 09/04/2007, Contact: Sean Mickal 504–862–2319.

*EIS No. 20070302, Final EIS, USA, NM*, Cannon Air Force Base (AFB), Proposal to Beddown, or Locate Air Force Special Operations Command (AFSOC), Implementation, Base Realignment and Closure (BRAC), NM, Wait Period Ends: 08/20/2007, Contact: Carl T. Hoffman 850–884–5984.

*EIS No. 20070303, Draft EIS, FRA, CA*, Bay Area to Central Valley High-Speed Train (HST) Project, Provide a Reliable High-Speed Electrified Train System to Link Bay Area Cities to the Central Valley, Sacramento, and South California, Comment Period Ends: 09/28/2007, Contact: David Valenstein 202–493–6368.

*EIS No. 20070304, Draft EIS, USN, VA*, Marine Corps Base Quantico (MCBQ) Virginia Project, Proposes Development of the Westside of MCBQ and the 2005 Base Realignment and Closure Action at MCBQ, Implementation, Quantico, VA, Comment Period Ends: 09/04/2007, Contact: Jeff Gardner 703–432–6784.

*EIS No. 20070305, Draft EIS, BPA, MT*, Libby (FEC) to Troy Section of BPA's Libby to Bonner Ferry 115-kilovolt Transmission Line Project, Rebuilding Transmission Line between Libby and Troy, Lincoln County, MT, Comment

Period Ends: 09/04/2007, Contact: Tish Easton 503–230–3469.

*EIS No. 20070306, Draft EIS, NPS, CO*, Curecanti National Recreation Area Resource Protection Study, Implementation, Black Canyon of the Gunnison National Forest, Gunnison and Montrose Counties, CO, Comment Period Ends: 10/19/2007, Contact: Roxanne Runkle 303–969–2377.

*EIS No. 20070307, Draft EIS, USA, 00*, Permanent Home Stationing of the 2/25th Stryker Brigade Combat Team (SBECT), To Address a Full Range of Alternatives for Permanently Stationing the 2/25th SBCT, Hawaii and Honolulu Counties, HI; Anchorage and Southeast Fairbanks Boroughs, AK; El Paso, Pueblo, and Fremont Counties, CO, Comment Period Ends: 09/04/2007, Contact: Michael Ackerman 410–436–2522.

**Amended Notices**

*EIS No. 20070291, Draft EIS, APH, 00*, PROGRAMMATIC—Introduction of Genetically Engineered (GE) Organisms, To Address Current and Future Technological Trends Resulting GE Plants, Implementation, Comment Period Ends: 09/11/2007, Contact: Michael J. Wach 301–734–0485.

Revision of FR Notice Published 07/13/2007: Correction to Comment Period from 08/27/2007 to 09/11/2007.

Dated: July 17, 2007.

**Robert W. Hargrove,**

*Director, NEPA Compliance Division, Office of Federal Activities.*

[FR Doc. E7–14106 Filed 7–19–07; 8:45 am]

**BILLING CODE 6560–50–P**

---

## ENVIRONMENTAL PROTECTION AGENCY

**[EPA–HQ–ORD–2007–0609; FRL–8442–6]**

## Board of Scientific Counselors, Endocrine Disrupting Chemicals (EDC) Research Program Mid-Cycle Review Meetings—Summer/Fall 2007

**AGENCY:** Environmental Protection Agency (EPA).

**ACTION:** Notice of meetings.

**SUMMARY:** Pursuant to the Federal Advisory Committee Act, Public Law 92–463, the Environmental Protection Agency, Office of Research and Development (ORD), gives notice of three meetings of the Board of Scientific Counselors (BOSC) EDC Mid-Cycle Subcommittee.

**DATES:** The first meeting (a teleconference call) will be held on Tuesday, August 21, 2007, from 1 p.m. to 3 p.m. The second meeting (a teleconference call) will be held on Friday, September 14, 2007, from 12 p.m. to 2 p.m. The third meeting (face-to-face meeting) will be held on Tuesday, September 18, 2007 from 10:30 a.m. to 3 p.m. All times noted are eastern time. The meetings may adjourn early if all business is finished. Requests for the draft agenda or for making oral presentations at the meetings will be accepted up to 1 business day before each meeting.

**ADDRESSES:** Participation in the conference calls will be by teleconference only—meeting rooms will not be used. Members of the public may obtain the call-in number and access code for the calls from Heather Drumm, whose contact information is listed under the **FOR FURTHER INFORMATION CONTACT** section of this notice. The face-to-face meeting will be held at the Key Bridge Marriott, 1401 Lee Highway, Arlington, Virginia 22209. Submit your comments, identified by Docket ID No. EPA–HQ–ORD–2007–0609, by one of the following methods:

- *www.regulations.gov:* Follow the on-line instructions for submitting comments.
- *E-mail:* Send comments by electronic mail (e-mail) to: *ORD.Docket@epa.gov,* Attention Docket ID No. EPA–HQ–ORD–2007–0609.
- *Fax:* Fax comments to: (202) 566–0224, Attention Docket ID No. EPA–HQ–ORD–2007–0609.
- *Mail:* Send comments by mail to: Board of Scientific Counselors, Endocrine Disrupting Chemicals (EDC) Mid-Cycle Subcommittee Meeting—Summer/Fall 2007 Docket, Mailcode: 28221T, 1200 Pennsylvania Ave., NW., Washington, DC 20460, Attention Docket ID No. EPA–HQ–ORD–2007–0609.
- *Hand Delivery or Courier:* Deliver comments to: EPA Docket Center (EPA/DC), Room B102, EPA West Building, 1301 Constitution Avenue, NW., Washington, DC., Attention Docket ID No. EPA–HQ–ORD–2007–0609. Note: this is not a mailing address. Such deliveries are only accepted during the docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

*Instructions:* Direct your comments to Docket ID No. EPA–HQ–ORD–2007–0609. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *www.regulations.gov* or e-mail. The *www.regulations.gov* Web site is an ''anonymous access'' system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through *www.regulations.gov,* your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses. For additional information about EPA's public docket visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm.*

*Docket:* All documents in the docket are listed in the *www.regulations.gov* index. Although listed in the index, some information is not publicly available, e.g., CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *www.regulations.gov* or in hard copy at the Board of Scientific Counselors, Endocrine Disrupting Chemicals (EDC) Mid-Cycle Subcommittee Meeting—Summer/Fall 2007 Docket, EPA/DC, EPA West, Room B102, 1301 Constitution Ave., NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the ORD Docket is (202) 566–1752.

**FOR FURTHER INFORMATION CONTACT:** The Designated Federal Officer via mail at: Heather Drumm, Mail Drop 8104–R, Office of Science Policy, Office of Research and Development, Environmental Protection Agency, 1300 Pennsylvania Ave., NW., Washington, DC 20460; via phone/voice mail at: (202) 564–8239; via fax at: (202) 565–

2911; or via e-mail at: *drumm.heather@epa.gov.*

**SUPPLEMENTARY INFORMATION:**

**General Information**

Any member of the public interested in receiving a draft BOSC agenda or making a presentation at either meeting may contact Heather Drumm, the Designated Federal Officer, via any of the contact methods listed in the **FOR FURTHER INFORMATION CONTACT** section above. In general, each individual making an oral presentation will be limited to a total of three minutes.

Proposed agenda items for the meetings include, but are not limited to: *Teleconference #1:* The objectives of the review; an overview of ORD's EDC research program; a summary of major changes in the EDC research program since 2005; *Teleconference #2:* An update on the revised EDC Multi-Year Plan; *face-to-face meeting:* The EDC research program's progress in response to recommendations from its 2005 BOSC review and other activities, subcommittee discussions. The meetings are open to the public.

*Information on Services for Individuals with Disabilities:* For information on access or services for individuals with disabilities, please contact Heather Drumm at (202) 564–8239 or *drumm.heather@epa.gov.* To request accommodation of a disability, please contact Heather Drumm, preferably at least 10 days prior to the meeting, to give EPA as much time as possible to process your request.

Dated: July 12, 2007.

**Mary Ellen Radzikowski,**

*Acting Director, Office of Science Policy.*

[FR Doc. E7–14063 Filed 7–19–07; 8:45 am]

BILLING CODE 6560–50–P

---

## ENVIRONMENTAL PROTECTION AGENCY

**[FRL–8441–5]**

### Proposed Amendment to CERCLA Section 122(h) Administrative Agreement for the Lower Passaic River Study Area Portion of the Diamond Alkali Superfund Site, Located in and About Essex, Hudson, Bergen and Passaic Counties, NJ

**AGENCY:** Environmental Protection Agency.

**ACTION:** Notice of proposed administrative settlement and opportunity for public comment.

**SUMMARY:** The United States Environmental Protection Agency (EPA) is proposing to enter into an amendment to an administrative settlement that resolved certain claims under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended (CERCLA) pursuant to Section 122(h) of CERCLA, 42 U.S.C 9622(h). In accordance with Section 122(i) of CERCLA, 42 U.S.C. 9622(i), this notice is being published to inform the public of the proposed amendment and of the opportunity to comment.

The amendment will incorporate twenty-nine (29) additional Settling Parties into Settlement Agreement, CERCLA Docket No. 02–2004–2011, binding the new Settling Parties to the terms and conditions of the Settlement Agreement, which became effective on June 22, 2004. As a result of this amendment, and a previous amendment, effective on November 9, 2005, the total number of Settling Parties under the Settlement Agreement will be seventy-one (71).

The new Settling Parties, and the previous Settling Parties, will be jointly and severally liable for the requirements of the Settlement Agreement, as amended, to pay up to $13,150,000 to fund EPA's performance of a remedial investigation and feasibility study (''RI/FS'') for the Lower Passaic River Study Area of the Diamond Alkali Superfund Site. Of this amount, $10,750,000 has already been paid; the amendment will make available up to $2,400,000 in additional contingent funding for those aspects of the RI/FS that EPA is performing. The Settling Parties have also recently entered into an administrative order on consent with EPA under which they will take over performance of most aspects of the RI/FS.

By entering into the amendment, the new Settling Parties will resolve their potential liability for Past Response Costs incurred in connection with the RI/FS (defined as those costs incurred through the effective date of the original Settlement Agreement, June 22, 2004, which total $2,829,802.62), as well as certain Future Response Costs incurred in connection with the RI/FS (those costs up to $13,150,000 that the Settling Parties have collectively committed to pay).

For thirty (30) days following the date of publication of this notice, EPA will receive written comments relating to the settlement. EPA will consider all comments received and may modify or withdraw its consent to the settlement if comments received disclose facts or considerations that indicate that the proposed settlement is inappropriate, improper or inadequate.

EPA's response to any comments received will be available for public inspection at EPA Region 2, 290 Broadway, 17th floor, New York, New York 10007–1866.

**DATES:** Comments must be submitted on or before August 20, 2007.

**ADDRESSES:** The proposed amendment is available on the internet at *http://www.ourpassaic.org*. Comments should reference the Lower Passaic River Study Area/Diamond Alkali Superfund Site, EPA Docket No. CERCLA–02–2004–2011, and should be addressed to the individual identified below.

**FOR FURTHER INFORMATION CONTACT:** Sarah Flanagan, Assistant Regional Counsel, New Jersey Superfund Branch, Office of Regional Counsel, U.S. Environmental Protection Agency, 17th Floor, 290 Broadway, New York, New York 10007–1866. Telephone: 212–637–3136.

Dated: June 18, 2007.

**George Pavlou,**

*Division Director, Emergency and Remedial Response Division.*

[FR Doc. E7–14004 Filed 7–19–07; 8:45 am]

BILLING CODE 6560–50–P

---

## ENVIRONMENTAL PROTECTION AGENCY

**[FRL–8442–2]**

### Public Water System Supervision Program Revisions for the State of Wisconsin

**AGENCY:** Environmental Protection Agency (EPA).

**ACTION:** Notice of tentative approval.

**SUMMARY:** Notice is hereby given that the State of Wisconsin is revising its approved Public Water System Supervision Program. Wisconsin has adopted the Arsenic Rule for all community and nontransient, noncommunity water systems which, among other things, changes the arsenic maximum contaminant level from 0.050 mg/L to 0.010 mg/L to improve public health by reducing exposure to arsenic in drinking water.

EPA has determined that these revisions are no less stringent than the corresponding federal regulations. Therefore, EPA intends to approve these program revisions. This approval action does not extend to public water systems (PWSs) in Indian Country, as that term is defined in 18 U.S.C. 1151. By approving these rules, EPA does not intend to affect the rights of federally recognized Indian tribes in Wisconsin, nor does it intend to limit existing rights of the State of Wisconsin.

All interested parties may request a public hearing. A request for a public hearing must be submitted by August 20, 2007, to the Regional Administrator at the EPA Region 5 address shown below. Frivolous or insubstantial requests for a hearing may be denied by the Regional Administrator. However, if a substantial request for a public hearing is made by August 20, 2007, a public hearing will be held.

If no timely and appropriate request for a hearing is received and the Regional Administrator does not elect to hold a hearing on her own motion, this determination shall become final and effective on August 20, 2007.

Any request for a public hearing shall include the following information: The name, address, and telephone number of the individual, organization, or other entity requesting a hearing; a brief statement of the requesting person's interest in the Regional Administrator's determination and a brief statement of the information that the requesting person intends to submit at such hearing; and the signature of the individual making the request, or, if the request is made on behalf of an organization or other entity, the signature of a responsible official of the organization or other entity.

**ADDRESSES:** All documents relating to this determination are available for inspection between the hours of 7:45 a.m. and 4:30 p.m., Monday through Friday, at the following offices: Wisconsin Department of Natural Resources, DG–2, 2nd Floor, 101 South Webster, PO Box 921, Madison, Wisconsin, 53707, and the United States Environmental Protection Agency, Region 5, Ground Water and Drinking Water Branch (WG–15J), 77 West Jackson Boulevard, Chicago, Illinois 60604.

**FOR FURTHER INFORMATION CONTACT:** Joe Janczy, EPA Region 5, Ground Water and Drinking Water Branch, at the address given above, by telephone at (608) 267–2763, or at *janczy.joseph@epa.gov.*

**Authority:** (Sec. 1413 of the Safe Drinking Water Act, as amended, 42 U.S.C. 3006–2 (1996), and 40 CFR Part 142 of the National Primary Drinking Water Regulations).

Dated: July 2, 2007.

**Walter Kovalick,**

*Acting Regional Administrator, Region 5.*

[FR Doc. E7–14065 Filed 7–19–07; 8:45 am]

BILLING CODE 6560–50–P

## ENVIRONMENTAL PROTECTION AGENCY

**[EPA–HQ–OW–2007; FRL–8442–1]**

### 2007 Water Efficiency Leader Awards—Call for Applicants

**AGENCY:** Environmental Protection Agency (EPA).

**ACTION:** Notice.

**SUMMARY:** This notice announces the opening of the application period for the U.S. EPA's second annual Water Efficiency Leader Awards. The awards recognize those organizations and individuals who are providing leadership and innovation in water efficient products and practices. These awards are intended to help foster a nationwide ethic of water efficiency, as well as to inspire, motivate, and recognize efforts to improve water efficiency. This program will enable EPA to document "best practices", share information, encourage an ethic of water efficiency, and create a network of water efficiency leaders. Recognition will be given on the basis of persuasive community or organizational leadership in the area of water efficiency, originality and innovativeness, national/global perspective and implications, and overall improvements in water efficiency. Actual (as opposed to anticipated) results are preferred and applicants should be able to demonstrate the amount of water saved. Candidates may be from anywhere in the United States, they may work in either the public or the private sector, and they may be either self-nominated or nominated by a third party. The following sectors are encouraged to apply: Corporations, Industry, Individuals, Non-Governmental Organizations and other Associations, Institutions, and Teams, Local, State, Tribal, and Federal Governments, and Military Individuals and Organizations. In order to be considered, applicants must have a satisfactory compliance record with respect to environmental regulations and requirements. Applications will be judged by a panel of national water efficiency experts from a variety of sectors. The panelists will provide recommendations to EPA, who will then make the final decision. EPA reserves the right to contact nominees for additional information should it be deemed necessary.

*To Apply:* Send a one page description (single sided) of the water efficient project being nominated. Also send a completed and signed application form found at *http://www.epa.gov/water/wel.*

**DATES:** Applications must be postmarked by August 17, 2007 in order to be considered.

**ADDRESSES:** Send applications to: Bob Rose, 1200 Pennsylvania Ave., NW., Mail Code 4101M, Washington, DC 20460. Additional information on the recognition program is available at *www.epa.gov/water/wel.*

**FOR FURTHER INFORMATION CONTACT:** Bob Rose, Telephone: (202) 564–0322. E-mail: *rose.bob@epa.gov.*

Dated: July 16, 2007.

**Benjamin H. Grumbles,**

*Assistant Administrator for Water.*

[FR Doc. E7–14062 Filed 7–19–07; 8:45 am]

BILLING CODE 6560–50–P

## FEDERAL ELECTION COMMISSION

### Sunshine Act Notices

**DATE AND TIME:** Thursday, July 26, 2007 at 10 a.m.

**PLACE:** 999 E Street, NW., Washington, DC (Ninth Floor).

**STATUS:** This Meeting Will be Open to the Public.

**ITEMS TO BE DISCUSSED:** Correction and Approval of Minutes.

Advisory Opinion 2007–09: Kerry-Edwards 2004, Inc., and Kerry Edwards 2004 General Election Legal and Accounting Compliance ("GELAC") Fund.

Report of the Audit Division on Ted Poe for Congress.

Management and Administrative Matters.

**PERSON TO CONTACT FOR INFORMATION:** Mr. Robert Biersack, Press Officer, Telephone: (202) 694–1220.

**Mary W. Dove,**

*Secretary of the Commission.*

[FR Doc. 07–3567 Filed 7–18–07; 2:46 pm]

BILLING CODE 6715–07–M

## FEDERAL RESERVE SYSTEM

### Change in Bank Control Notices; Acquisition of Shares of Bank or Bank Holding Companies

The notificants listed below have applied under the Change in Bank Control Act (12 U.S.C. 1817(j)) and § 225.41 of the Board's Regulation Y (12 CFR 225.41) to acquire a bank or bank holding company. The factors that are considered in acting on the notices are set forth in paragraph 7 of the Act (12 U.S.C. 1817(j)(7)).

The notices are available for immediate inspection at the Federal

Reserve Bank indicated. The notices also will be available for inspection at the office of the Board of Governors. Interested persons may express their views in writing to the Reserve Bank indicated for that notice or to the offices of the Board of Governors. Comments must be received not later than August 6, 2007.

**A. Federal Reserve Bank of Chicago** (Burl Thornton, Assistant Vice President) 230 South LaSalle Street, Chicago, Illinois 60690-1414:

*1. David A. Davis*, Muskego, Wisconsin; to acquire voting shares of Capital Commerce Bancorp, Inc., and thereby indirectly acquire voting shares of MW Bank, both of Milwaukee, Wisconsin.

Board of Governors of the Federal Reserve System, July 17, 2007.

**Robert deV. Frierson,**

*Deputy Secretary of the Board.*

[FR Doc. E7–14066 Filed 7–19–07; 8:45 am]

**BILLING CODE 6210–01–S**

## GENERAL SERVICES ADMINISTRATION

### Request for Comments on Proposed Federal Emergency Travel Guide

**AGENCY:** Office of Governmentwide Policy, General Services Administration (GSA).

**ACTION:** Notice of intent and request for comments.

**SUMMARY:** The General Services Administration (GSA) is proposing to create a Federal Emergency Travel Guide in the event of evacuation, catastrophic event or natural disaster. The guide is intended to prepare the Federal Government to continue official travel operations in an emergency situation while safeguarding Federal employees officially away from their official or temporary duty stations. The guide, non-regulatory in nature, will serve as a supplement to the Federal Travel Regulation (FTR) (41 CFR chapters 300–304).

**DATES:** Please submit comments by September 18, 2007.

**ADDRESSES:** Written comments should be sent to Ms. Jane Groat, Travel Policy Management (MTT), Office of Governmentwide Policy, General Services Administration, 1800 F Street, NW., Washington, DC 20405. E-mail comments may be sent to *perdiem@gsa.gov*. Please entitle your letter or e-mail with ''Federal Emergency Travel Guide comments''.

**FOR FURTHER INFORMATION CONTACT:** Jane Groat, Travel Policy Management (MTT), telephone 202–501–4318.

**SUPPLEMENTARY INFORMATION:** To access the draft guide, you may visit *http://www.gsa.gov/travelpolicy* (click Library). A hard copy of the draft guide is not available.

GSA is interested to learn from Federal, (1) how to improve the draft guide; (2) whether Federal agencies and employees agree that the guide will be a useful tool; (3) what Federal agencies already have related policies in place (and identify a web site)—employees on site in support of an incident of National significance are generally under the effect of a National Response Plan and follow those established guides; (4) what kinds of things need to be added to the guide for governmentwide benefit; and (5) any other related comment/suggestion.

If you comment, please include your name, title, your capacity (i.e., an employee, an official, or an Emergency Response Team), telephone, agency, email and hard addresses. Are you commenting from personal experience as a traveler, a supervisor/manager, or an Emergency Response Team? Have you had a need for emergency guides? If you survived a horrific event or emergency, what help/assistance was needed the most, where did expectations and support fall short, and what would your recommendations be?

If you are a private sector travel or transportation service provider to the Government, we will also welcome your comments.

Dated: July 16, 2007.

**Patrick Mc Connell,**

*Acting Director, Travel Policy Management.*

[FR Doc. E7–14052 Filed 7–19–07; 8:45 am]

**BILLING CODE 6820–14–P**

## DEPARTMENT OF HEALTH AND HUMAN SERVICES

### Centers for Medicare & Medicaid Services

**[Document Identifier: CMS–10224, CMS–10240 and CMS–10052]**

### 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:* HCPCS Level II Code Modification Request Process; *Use:* For Medicare and other health insurance programs to ensure that claims are processed in an orderly and consistent manner, standardized coding systems are essential. The Healthcare Common Procedure Coding System (HCPCS) Level II Code Set is one of the standard code sets used for this purpose. Level II of the HCPCS, also referred to as alpha-numeric codes, is a standardized coding system that is used primarily to identify products, supplies, and services not included in the Current Procedural Terminology (CPT) codes, such as ambulatory services and durable medical equipment, prosthetics, orthotics, and supplies (DMEPOS) when used in the home or outpatient setting. As technology evolves and new products are developed, there are continuous changes to the HCPCS codeset. Modifications to the HCPCS are initiated via application form submitted by any interested stakeholder. These applications have been received on an on-going basis with an annual deadline for each cycle. In October 2003, the Secretary of Health and Human Services delegated CMS authority to maintain and distribute HCPCS Level II Codes. As a result, the National Panel was delineated and CMS continued with the decision-making process under its current structure, the CMS HCPCS Workgroup.

CMS' Council on Technological Innovation (CTI) has instituted a number of improvements to the HCPCS process. Specific process refinements include public notification of CMS' preliminary decisions, and a new opportunity to respond to CMS' preliminary decisions at a public meeting before a final decision is reached by the workgroup. CMS has streamlined the form into a user-friendly application. The content of the material is the same, but the questions have been refined. CMS is also preparing a system of records (SOR) notice.

Applications are received, and distributed to all workgroup members. Workgroup members review the material and provide comments at the HCPCS workgroup meetings. Discussions are posted to CMS' HCPCS website. Final decisions are released to the applicant via letter; and all resulting modifications to the HCPCS codes are reflected on the HCPCS update. *Form Number:* CMS–10224 (OMB#: 0938–New); *Frequency:* Reporting: Occasionally; *Affected Public:* Business or other for-profit and State, Local or Tribal Government; *Number of Respondents:* 300; *Total Annual Responses:* 300; *Total Annual Hours:* 3,300.

2. *Type of Information Collection Request:* New collection; *Title of Information Collection:* Data Collection for the Nursing Home Value-Based Purchasing (NHVBP) Demonstration; *Use:* The NHVBP Demonstration is a CMS ''pay-for-performance'' initiative to improve the quality of care furnished to Medicare beneficiaries residing in nursing homes. Under this three-year demonstration project, CMS will assess the performance of nursing homes based on selected quality measures, and then make additional payments to those nursing homes that achieve a higher performance based on those measures. In the first year of the demonstration, quality will be assessed based on the following four domains: staffing, appropriate hospitalizations, outcome measures from the minimum data set (MDS), and survey deficiencies. Additional quality measures may be added in the second and third years of the demonstration as deemed appropriate.

The main purpose of the NHVBP data collection effort is to gather information that will enable CMS to determine which nursing homes will be eligible to receive incentive payments under the NHVBP Demonstration. All measures included in the MDS outcomes, survey deficiency, and appropriate hospitalization domains can be calculated from existing secondary data sources, such as the MDS, annual nursing home certification surveys, and Medicare claims data. However, for the staffing domain, no satisfactory alternative source for these data has been identified. Therefore, CMS will collect payroll-based staffing and resident census information to help assess the quality of care in participating nursing homes. CMS will additionally collect data on two measures, staff immunization status and use of resident care experience surveys, which may be included in the payment determination during the second and third years of the demonstration. *Form Number:* CMS–10240 (OMB#: 0938–New); *Frequency:* Reporting: Once; *Affected Public:* Business or other for-profit and not-for-profit institutions; *Number of Respondents:* 1,250; *Total Annual Responses:* 2,000; *Total Annual Hours:* 49,170.

3. *Type of Information Collection Request:* Extension of a currently approved collection; *Title of Information Collection:* Recognition of pass-through payment for additional (new) categories of devices under the Outpatient Prospective Payment System and Supporting Regulations in 42 CFR, Part 419; *Use:* Section 201(b) of the Balanced Budget Act of 1999 amended section 1833(t) of the Social Security Act (the Act) by adding new section 1833(t)(6). This provision requires the Secretary to make additional payments to hospitals for a period of 2 to 3 years for certain drugs, radiopharmaceuticals, biological agents, medical devices and brachytherapy devices. Section 1833(t)(6)(A)(iv) establishes the criteria for determining the application of this provision to new items. Section 1833(t)(6)(C)(ii) provides that the additional payment for medical devices be the amount by which the hospital's charges for the device, adjusted to cost, exceed the portion of the otherwise applicable hospital outpatient department fee schedule amount determined by the Secretary to be associated with the device. Section 402 of the Benefits Improvement and Protection Act of 2000 made changes to the transitional pass-through provision for medical devices. The most significant change is the required use of categories as the basis for determining transitional pass-through eligibility for medical devices, through the addition of section 1833(t)(6)(B) of the Act.

Interested parties such as hospitals, device manufacturers, pharmaceutical companies, and physicians apply for transitional pass-through payment for certain items used with services covered in the outpatient prospective payment system. After CMS receives all requested information, CMS will evaluate the information to determine if the creation of an additional category of medical devices for transitional pass-through payments is justified. *Form Number:* CMS–10052 (OMB#: 0938–0857); *Frequency:* Reporting: Yearly; *Affected Public:* Business or other for-profit; *Number of Respondents:* 10; *Total Annual Responses:* 10; *Total Annual Hours:* 160.

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 E-mail 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 at the address below, no later than 5 p.m. on September 18, 2007.

CMS, Office of Strategic Operations and Regulatory Affairs, Division of Regulations Development—C, *Attention:* Bonnie L Harkless, Room C4–26–05, 7500 Security Boulevard, Baltimore, Maryland 21244–1850.

Dated: July 12, 2007.

**Michelle Shortt,**

*Director, Regulations Development Group, Office of Strategic Operations and Regulatory Affairs.*

[FR Doc. E7–13904 Filed 7–19–07; 8:45 am]

BILLING CODE 4120–01–P

## DEPARTMENT OF HEALTH AND HUMAN SERVICES

### Centers for Medicare & Medicaid Services

**[Document Identifier: CMS–R–244 and CMS–18F5]**

### 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:* Extension of a currently approved collection; *Title of Information Collection:* The Medicare and Medicaid Programs: Programs of All-inclusive Care for the Elderly (PACE); *Form Number:* CMS–R–244 (OMB#: 0938–0790); *Use:* PACE organizations must demonstrate their ability to provide quality community-based care for the frail elderly who meet their State's nursing home eligibility standards using capitated payments from Medicare and the State. PACE programs must provide all Medicare and Medicaid covered services including hospital, nursing home, home health, and other specialized services. This collection is necessary to ensure that only appropriate organizations are selected to become PACE organizations and that CMS has the information necessary to monitor the care they provide; *Frequency:* Reporting—Once and on occasion; *Affected Public:* Not-for-profit institutions and State, Local, or Tribal Governments; *Number of Respondents:* 54; *Total Annual Responses:* 108; *Total Annual Hours:* 44131.50.

2. *Type of Information Collection Request:* Extension of a currently approved collection; *Title of Information Collection:* Application for Hospital Insurance Benefits; *Form Number:* CMS–18F5 (OMB#: 0938–0251); *Use:* The CMS–18F5 form is used to establish entitlement to and enrollment in Part A of Medicare for beneficiaries who are not automatically entitled to Medicare Part A under Title XVIII of the Social Security Act and must file an application. Sections 226(a), 227 and 1818A of the Social Security Act and sections 42 CFR 406.10, 406.11 and 406.20 outline the requirements for entitlement to Medicare hospital insurance (Part A). Section 42 CFR 406.6 provides information about who needs to file an application for Part A and who does not. Section 42 CFR 406.7 lists the CMS–18F5 form as the application to be used by individuals applying for Part A of Medicare. The CMS–18F5 form was designed to capture all the information needed to make a determination of an individual's entitlement to hospital insurance (Part A); *Frequency:* Reporting—once; *Affected Public:* Individuals or households; *Number of Respondents:* 50,000; *Total Annual Responses:* 50,000; *Total Annual Hours:* 12,495.

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 E-mail 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.

Written comments and recommendations for the proposed information collections must be mailed or faxed within 30 days of this notice directly to the OMB desk officer: OMB Human Resources and Housing Branch, *Attention:* Carolyn Lovett, New Executive Office Building, Room 10235, Washington, DC 20503, Fax Number: (202) 395–6974.

Dated: July 12, 2007.

**Michelle Shortt,**

*Director, Regulations Development Group, Office of Strategic Operations and Regulatory Affairs.*

[FR Doc. E7–13905 Filed 7–19–07; 8:45 am]

**BILLING CODE 4120–01–P**

---

## DEPARTMENT OF HEALTH AND HUMAN SERVICES

### Food and Drug Administration

### Blood Products 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*: Blood Products 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 August 16, 2007, from 8 a.m. to 5 p.m.

*Location*: Doubletree Hotel and Executive Meeting Center, 8120 Wisconsin Ave., Bethesda, MD 20814.

*Contact Person*: Donald W. Jehn or Pearline K. Muckelvene, Center for Biologics Evaluation and Research, Food and Drug Administration, 1401 Rockville Pike (HFM–71), Rockville, MD 20852, 301–827–0314, or FDA Advisory Committee Information Line, 1–800–741–8138 (301–443–0572 in the Washington, DC area), code 3014519516. 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 and call the appropriate advisory committee hot line/phone line to learn about possible modifications before coming to the meeting.

*Agenda*: On August 16, 2007, the Committee will hear updates on the following topics: (1) Summary of the May 10 through 11, 2007, and the August 6 through 7, 2007, meetings of the Department of Health and Human Services Advisory Committee on Blood Safety and Availability; (2) summary of the April 25 through 26, 2007, FDA Workshop on Immune Globulins for Primary Immune Deficiency Diseases: Antibody Specificity, Potency and Testing; and (3) summary of the August 15, 2007, FDA Workshop on Licensure of Apheresis Blood Products. The Committee will then hear informational presentations relating to World Health Organization (WHO) biological standards on the following topics: (1) Summary of the January 29 through 30, 2007, WHO meeting with WHO collaborating centers for biological standards and standardization to support the development of WHO biological reference preparations for high risk blood safety-related in vitro diagnostics; (2) potency and safety standards for plasma derivatives; and (3) joint FDA/WHO minimum potency standards for certain blood grouping reagents. The Committee will hear the response of the Office of Blood Research and Review to their office level site visit of July 22, 2005. In the afternoon the Committee will discuss measles antibody levels in U.S. Immune Globulin products.

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/ohrms/dockets/ac/acmenu.htm*, click on the year 2007 and 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 August 8, 2007. Oral presentations from the public will be scheduled between approximately 11:15 a.m. and 11:45 p.m. and between approximately 3:30 p.m. and 4 p.m. on August 16, 2007. Those desiring to make 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 July 31, 2007. 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 August 1, 2007.

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 Donald W. Jehn or Pearline K. Muckelvene at least 7 days in advance of the meeting.

Notice of this meeting is given under the Federal Advisory Committee Act (5 U.S.C. app. 2).

Dated: July 16, 2007.

**Randall W. Lutter,**

*Deputy Commissioner for Policy.*

[FR Doc. E7–14088 Filed 7–19–07; 8:45 am]

**BILLING CODE 4160–01–S**

---

## DEPARTMENT OF HEALTH AND HUMAN SERVICES

### Food and Drug Administration

### Joint Meeting of the Cardiovascular and Renal Drugs Advisory Committee and the Drug Safety and Risk Management 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 Committees*: Cardiovascular and Renal Drugs Advisory Committee and the Drug Safety and Risk Management Advisory Committee.

*General Function of the Committees*: To provide advice and recommendations to the agency on FDA's regulatory issues.

*Date and Time*: The meeting will be held on September 11, 2007, from 8 a.m. to 5 p.m.

*Location*: Hilton Washington DC North/Gaithersburg, The Ballrooms, 620 Perry Pkwy., Gaithersburg, MD, 301–977–8900.

*Contact Person*: Mimi Phan, Center for Drug Evaluation and Research (HFD–21), Food and Drug Administration, 5600 Fishers Lane (for express delivery, 5630 Fishers Lane, rm. 1093), Rockville, MD 20857, 301–827–7001, FAX: 301–827–6776, e-mail: *Mimi.Phan@fda.hhs.gov*, or FDA Advisory Committee Information Line, 1–800–741–8138 (301–443–0572 in the Washington, DC area), code 3014512533 or 3014512535. 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 and call the appropriate advisory committee hot line/phone line to learn about possible modifications before coming to the meeting.

*Agenda*: The committee will discuss updated information on the risks and benefits of erythropoeisis-stimulating agents (ARANESP, Amgen, Inc., EPOGEN, Amgen, Inc., and PROCRIT, Amgen, Inc.) when used in the treatment of anemia due to chronic renal failure. This discussion follows a March 9, 2007, FDA Public Health Advisory regarding the use of these agents (*http://www.fda.gov/cder/drug/advisory/RHE2007.htm*).

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/ohrms/dockets/ac/acmenu.htm*, click on the year 2007 and 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 August 27, 2007. Oral presentations from the public will be scheduled between approximately 1 p.m. and 2 p.m. Those desiring to make 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 August 17, 2007. 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 August 20, 2007.

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 Mimi Phan at 301–827–7001, at least 7 days in advance of the meeting.

Notice of this meeting is given under the Federal Advisory Committee Act (5 U.S.C. app. 2).

Dated: July 16, 2007.

**Randall W. Lutter,**

*Deputy Commissioner for Policy.*

[FR Doc. E7–14086 Filed 7–19–07; 8:45 am]

**BILLING CODE 4160–01–S**

---

## DEPARTMENT OF HEALTH AND HUMAN SERVICES

### Food and Drug Administration

**[Docket No. 2007N–0277]**

### Food Labeling: Use of Symbols to Communicate Nutrition Information, Consideration of Consumer Studies and Nutritional Criteria; Public Hearing; Request for Comments

**AGENCY:** Food and Drug Administration, HHS.

**ACTION:** Notice of public hearing; request for comments.

**SUMMARY:** The Food and Drug Administration (FDA) is announcing a public hearing concerning the use of symbols to communicate nutrition

information on food labels. The purpose of the hearing is for FDA to solicit information and comments from interested persons about programs currently in use regarding the use of symbols to communicate nutrition information on food labels.

**DATES:** The public hearing will be held on September 10 and 11, 2007, from 9 a.m. to 5 p.m. See section V of this document for additional dates associated with registration and participation in the hearing. Submit written or electronic comments (i.e., submissions other than notices of participation and written material associated with an oral presentation) by November 12, 2007. The administrative record of the hearing will remain open until November 12, 2007.

**ADDRESSES:** *Public hearing*. The public hearing will be held at The Inn & Conference Center by Marriott, University of Maryland, University College, 3501 University Blvd. E., Adelphi, Maryland 20783.

*Registration and notice of participation and written material associated with an oral presentation*. Submit electronic requests to register and notices of participation for the hearing to *http://www.cfsan.fda.gov/register.html*. We encourage you to use this method to submit notices of participation, if possible. Submit written requests to register and notices of participation, and written material associated with an oral presentation to: Kathy Houston, Z-Tech Corp., 1803 Research Blvd., suite 301, Rockville, MD 20850, 301–251–4976, FAX: 301–315–2801, or e-mail: *khouston@z-techcorp.com*.

*Comments*. Submit written comments to the Division of Dockets Management (HFA–305), Food and Drug Administration, 5630 Fishers Lane, rm. 1061, Rockville, MD 20852. Submit electronic comments to *http://www.fda.gov/dockets/ecomments*. For additional information on submitting comments, see section VI in this document.

**FOR FURTHER INFORMATION CONTACT:** *To submit an oral or written notice of participation by phone, by fax, or by e-mail, or to submit written material associated with an oral presentation by fax or by e-mail*: Kathy Houston, Z-Tech Corp., 1803 Research Blvd., suite 301, Rockville, MD 20850.

*For all other questions about the hearing or if you need special accommodations due to a disability*: Juanita Yates, Center for Food Safety and Applied Nutrition, Food and Drug Administration, 301–436–1731, e-mail: *Juanita.Yates@fda.hhs.gov*.

**SUPPLEMENTARY INFORMATION:**

## I. Background

In the United States, the Nutrition Labeling and Education Act of 1990 (the 1990 amendments) (Public Law 101–535) amended the Federal Food, Drug, and Cosmetic Act (the act) to require nutrition labeling on the labels of packaged foods to enable consumers to make more informed and healthier food choices in the context of their daily diet. In 1993, FDA established regulations that implemented the 1990 amendments, including provisions concerning the use of claims on the label or in labeling of a food. Among these regulations, the agency set forth general principles for nutrient content claims (21 CFR 101.13), which are claims that characterize the level of a nutrient in a food (e.g., ''low fat,'' ''good source of fiber''), and for health claims (21 CFR 101.14), which are claims that characterize the relationship of a food substance to a disease or health-related condition (e.g., ''calcium may reduce the risk of osteoporosis'').

### *A. Use of Nutrition Symbols on Food Labels in the United States.*

In recent years, domestic manufacturers and retailers have begun to include symbols that indicate nutritional quality on the label or in labeling of a food. Symbol programs have been instituted by companies to promote their products and provide consumers with easily understandable nutrition information to aid them in their food purchases. Various food manufacturers, grocery stores, trade organizations, and health organizations have developed, or are currently developing, symbols and icons that indicate specific nutritional attributes of food products. Although each symbol intends to indicate that the food product bearing the symbol is a healthful choice, each symbol program has different nutrient requirements. The selected nutrients and the nutrient levels required for eligibility vary among the different symbol programs in use. With the increasingly widespread availability of these symbols from manufacturers, retailers, and third party organizations, it is possible that eligible food products could bear multiple nutrition symbols.

### *B. Use of Nutrition Symbols on Food Labels in Other Countries*

A few countries around the world have already instituted voluntary labeling systems for government-designed front-label[1] nutrition symbols. These symbol systems vary in their format. Some systems have detailed graphic illustrations that indicate the content of a number of selected nutrients, while others simply present a single icon indicating that a food is healthful (with further information available elsewhere, such as in booklets and web sites). Also in use internationally are industry-designed nutrition symbol systems that are available for use in countries that do not have a government-designed symbol program or, in certain countries, that exist as alternatives to the government-designed symbols.

## II. Purpose and Scope of the Hearing

The purpose of the hearing is for FDA to solicit information and comments from interested persons about programs currently in use regarding the use of symbols to communicate nutrition information on food labels.

This notice describes the scope of the hearing. We invite information and comment on the issues and questions in section III of this document. If you are interested in this hearing or this subject, you may address as many of the following questions as you wish. We do not expect you to address all questions. When possible, please provide scientific information and data in support of your comments. In addition, to the extent possible, please provide as specific information as is feasible about the estimated costs and benefits associated with your responses (e.g., the costs and benefits of current practices and/or the cost and benefits of any recommendations you may make).

## III. Issues and Questions for Discussion

The following issues and questions will be discussed at the public hearing:

*Issue 1*: There are many food label nutrition symbol programs currently in the domestic and international marketplace. Each system uses different nutrition criteria and requirements regarding eligibility for use. The agency would like information on the food products that bear nutrition symbols and the nutrient requirements for those symbols.

Question 1. In what product categories are nutrition symbols used (e.g., packaged foods, fresh produce, meat/poultry, seafood)?

Question 2. Which symbols are nutrient specific, and which are summary symbols based on multiple nutrients?

[1]As used in this notice, the term ''front label'' means the part of the label that is most likely to be displayed, presented, shown, or examined under customary conditions of display for retail sale. In the United States, the front label is known as the principal display panel (21 CFR 1.1).

Question 3. What are the nutritional criteria, including calories, included in a symbol system and how were those particular nutritional criteria chosen for inclusion?

Question 4. What nutrient thresholds and/or algorithms are used to determine if a food product may display a nutrient specific or summary symbol?

Question 5. Are nutrition symbols presented together with front label nutrition claims such as ''low fat'' or ''good source of calcium'' and, if so, to what extent and for what types of claims?

Question 6. Are there programs to educate consumers to understand the nutrition symbols or is all information contained in the symbols? When education programs are available, how are they presented?

*Issue 2*: The presence of nutrition symbols could affect the food purchasing decisions of consumers. Symbols could help consumers make food choices, but it is also possible that symbols could introduce confusion when making decisions. The agency would like information on consumer research that supported the development of these programs and research that illustrates how these programs are understood and utilized by consumers.

Question 7. What are consumer attitudes toward nutrition symbols?

Question 8. What are consumer attitudes toward products or brands that carry a nutrition symbol compared to other products or brands in the same product category (e.g., cereals) and in other categories that do not carry such a symbol?

Question 9. What are consumer interpretations of symbol-carrying products or brands in terms of their overall healthfulness, specific health benefits, featured nutrition attributes, nonfeatured nutrition attributes, quality, safety, and any other non-nutrition attributes?

Question 10. What is consumer perception of the presence of multiple and different nutrition symbols on front labels of different brands in a given product category, e.g., cereals?

Question 11. What is consumer interpretation of the co-existence on the food label of symbols and/or other nutrition messages, when present, and quantitative nutrition information (e.g., the Nutrition Facts label that appears on foods in the United States)?

Question 12. What is consumer interpretation of the co-existence of front-label nutrition symbols and nutrition symbols present on the tags of supermarket shelves, when available?

Question 13. When do consumers use nutrition symbols and what do they use them for?

Question 14. Do nutrition symbols on food labels direct consumers toward purchase of foods that bear them and, if so, to what extent?

Question 15. Do symbols affect the nutritional quality of the total diet of consumers who use the symbols and, if so, to what extent?

*Issue 3*: The availability of a nutrition symbol for use on the food label could have an impact on costs for both industry and for consumers. The agency would like information on possible economic impacts.

Question 16. To what extent, if any, have products been developed or re-formulated to qualify them for a given nutrition symbol?

Question 17. What are the costs associated with product development, re-formulation, or both?

Question 18. What are the costs associated with putting symbols on packages?

Question 19. What, if any, are the price differences between symbol-carrying products and other products within the same category?

Question 20. Has inclusion of nutrition symbols on the labels of food products affected the sales of those products?

## IV. Notice of Hearing Under 21 CFR Part 15

By delegation from the Commissioner of Food and Drugs (the Commissioner) (Staff Manual Guide 1410.21 paragraph 1.f. (5)), the Assistant Commissioner for Policy finds that it is in the public interest to permit persons to present information and views at a public hearing regarding the use of symbols to communicate nutrition information on food labels and is announcing that the public hearing will be held in accordance with part 15 (21 CFR part 15). The presiding officer will be the Commissioner or his designee. The presiding officer will be accompanied by a panel of FDA employees with relevant expertise.

Persons who wish to participate in the hearing (either by making a presentation or as a member of the audience) must file a notice of participation (see **DATES, ADDRESSES, FOR FURTHER INFORMATION CONTACT**, and section V of this document). By delegation from the Commissioner (Staff Manual Guide 1410.21 paragraph 1.f. (5)), the Assistant Commissioner for Policy has determined under § 15.20(c) that advance submissions of oral presentations are necessary for the panel to formulate useful questions to be posed at the hearing under § 15.30(e), and that the submission of a comprehensive outline or summary is an acceptable alternative to the submission of the full text of the oral presentation. For efficiency, we request that individuals and organizations with common interests consolidate their requests for oral presentation and request time for a joint presentation through a single representative. After reviewing the notices of participation and accompanying information, we will schedule each oral presentation and notify each participant of the time allotted to the presenter and the approximate time that the presentation is scheduled to begin. If time permits, we may allow interested persons who attend the hearing but did not submit a notice of participation in advance to make an oral presentation at the conclusion of the hearing. The hearing schedule will be available at the hearing.

After the hearing, the schedule and a list of participants will be placed on file in the Division of Dockets Management (see **ADDRESSES**) under the docket number listed in brackets in the heading of this notice.

To ensure timely handling of any mailed notices of participation, written material associated with presentations, or comments, any outer envelope should be clearly marked with the docket number listed in brackets in the heading of this notice along with the statement ''Food Labeling: Use of Symbols to Communicate Nutrition Information, Consideration of Consumer Studies and Nutritional Criteria; Public Hearing.''

Under § 15.30(f), the hearing is informal, and the rules of evidence do not apply. No participant may interrupt the presentation of another participant. Only the presiding officer and panel members may question any person during or at the conclusion of each presentation.

Public hearings under part 15 are subject to FDA's policy and procedures for electronic media coverage of FDA's public administrative proceedings (part 10 (21 CFR part 10, subpart C)). Under § 10.205, representatives of the electronic media may be permitted, subject to the procedures and limitations in § 10.206, to videotape, film, or otherwise record FDA's public administrative proceedings, including presentations by participants. The hearing will be transcribed as stipulated in § 15.30(b). For additional information about transcripts, see section VII in this document.

Any handicapped persons requiring special accommodations to attend the hearing should direct those needs to the appropriate contact person (see **FOR FURTHER INFORMATION CONTACT**).

To the extent that the conditions for the hearing, as described in this document, conflict with any provisions set out in part 15, this notice acts as a waiver of these provisions as specified in §§ 10.19 and 15.30(h). In particular, § 15.21(a) states that the notice of hearing will provide persons an opportunity to file a written notice of participation with the Division of Dockets Management within a specified period of time. If the public interest requires, e.g., if a hearing is to be conducted within a short period of time, the notice may name a specific FDA employee and telephone number to whom an oral notice of participation may be given. If the public interest requires, the notice may also provide for submitting notices of participation at the time of the hearing. In this document, the conditions for the hearing specify that notices of participation be submitted electronically to an agency Web site, to a contact person who will accept notices of participation by mail, telephone, fax, or e-mail, or in person on the day of the hearing (as space permits). In addition, the conditions for the hearing specify that written material associated with an oral presentation be provided to a contact person (who will accept it by mail, fax, or e-mail) rather than to the Division of Dockets Management. We are using these procedures to facilitate the exchange of information between participants and the agency. By delegation from the Commissioner (Staff Manual Guide 1410.21 paragraph 1.f.(5)), the Assistant Commissioner for Policy finds under § 10.19 that no participant will be prejudiced, the ends of justice will thereby be served, and the action is in accordance with law if notices of participation are submitted by the procedures listed in this notice rather than to the Division of Dockets Management.

## V. How to Participate in the Hearing

Registration by submission of a notice of participation is necessary to ensure participation and will be accepted on a first-come, first-served basis. The notice of participation may be submitted electronically, orally, or by fax, mail, or e-mail (see **ADDRESSES** and **FOR FURTHER INFORMATION CONTACT**). We encourage you to submit your notice of participation electronically. A single copy of any notice of participation is sufficient.

The notice of participation must include your name, title, business affiliation (if applicable), address, telephone number, fax number (if available), and e-mail address (if available). If you wish to request an opportunity to make an oral presentation during the open public comment period of the hearing, your notice of participation also must include the title of your presentation, the sponsor of the oral presentation (e.g., the organization paying travel expenses or fees), if any; and the approximate amount of time requested for the presentation. Presentations will be limited to the questions and subject matter identified in section III of this document, and, depending on the number of requests received, we may be obliged to limit the time allotted for each presentation (e.g., 5 minutes each).

Under § 15.20(c), if you request an opportunity to make an oral presentation, you must submit your presentation (either as the full text of the presentation, or as a comprehensive outline or summary). You may submit your presentation by e-mail, fax, or mail. A single copy of your presentation is sufficient. See **ADDRESSES** and **FOR FURTHER INFORMATION CONTACT** for information on where to send your presentation.

Persons who wish to request an opportunity to make an oral presentation at the hearing must submit a notice of participation by August 24, 2007, and also must submit either the full text of the oral presentation, or a comprehensive outline or summary of the oral presentation, by August 31, 2007. All other persons wishing to attend the hearing must submit a notice of participation by August 31, 2007. Persons requiring special accommodations due to a disability must submit a notice of participation by August 31, 2007, and should inform the contact person of their request (see **FOR FURTHER INFORMATION CONTACT**). Individuals who request an opportunity to make an oral presentation will be notified of the scheduled time for their presentation prior to the hearing.

We also will accept notices of participation onsite on a first come, first served basis; however, the anticipated maximum seating capacity is 75 to 100, and registration will be closed when the maximum seating capacity is reached. Requests for an opportunity to make a presentation from individuals or organizations that did not make such a request in advance may be granted if time permits.

Persons who submit a notice of participation in advance of the hearing should check in at the on-site registration desk between 8:30 and 9 a.m. Persons who wish to submit a notice of participation onsite may do so at the registration desk between 8:30 and 9 a.m. on either day of the hearing. We encourage all participants to attend the entire hearing.

All submissions and comments received may be posted without change to *http://www.fda.gov/ohrms/dockets/default.htm*, including any personal information provided.

## VI. Request for Comments

Interested persons may submit to the Division of Dockets Management (see **ADDRESSES**) written or electronic comments for consideration at or after the hearing in addition to, or in place of, a request for an opportunity to make an oral presentation (see section V of this document). Submit two paper copies of any written comments, except that individuals may submit one copy. Comments are to be identified with the agency name and 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.

## VII. Transcripts

Transcripts of the hearing will be available for review at the Division of Dockets Management (see **ADDRESSES**) and on the Internet at *http://www.fda.gov/ohrms/dockets*approximately 30 days after the hearing. You may place orders for copies of the transcript through the Freedom of Information Office (HFI–35), Food and Drug Administration, 5600 Fishers lane, rm. 6–30, Rockville, MD 20857, at a cost of 10 cents per page.

Dated: July 13, 2007.

**Jeffrey Shuren,**

*Assistant Commissioner for Policy.*

[FR Doc. E7–14046 Filed 7–19–07; 8:45 am]

BILLING CODE 4160–01–S

---

# DEPARTMENT OF HEALTH AND HUMAN SERVICES

## Food and Drug Administration

## Food Safety and Defense . . . Be ALERT; Public Workshop

**AGENCY:** Food and Drug Administration, HHS.

**ACTION:** Notice of public workshop.

**SUMMARY:** The Food and Drug Administration (FDA), Office of Regulatory Affairs (ORA), Atlanta District and Southeast Regional Office (SER), in collaboration with Georgia Food Safety and Defense Task Force, and the Metro Environmental Health Directors Food Service Advisory

Committee, is announcing a public workshop entitled ''Food Safety and Defense . . . Be ALERT!'' This public workshop will provide information about how to control foodborne illness risk factors and how to secure food from intentional contamination (food defense awareness). The target audience will be operators of small, independent (non-chain) retail and food service establishments.

*Date and Time*: This public workshop will be held on Wednesday, August 15, 2007, from 9 a.m. to 3 p.m.

*Location*: The public workshop will be held at the Hilton Atlanta Northeast Hotel, 5993 Peachtree Industrial Blvd., Norcross, GA.

*Contact*: JoAnn Pittman, Food and Drug Administration, Atlanta District, Southeast Region, 60 8th St., NE., Atlanta, GA 30309, 404–253–1272, FAX: 404–253–1202, or e-mail: *JoAnn.Pittman@fda.hhs.gov*.

*Registration is at no charge*: The registration deadline is August 1, 2007; please see instructions in this document. Those accepted into the workshop will receive confirmation. Registration at the site is not guaranteed but, may be possible on a space available basis (100 maximum) on the day of the public workshop beginning at 9 a.m. If you need special accommodations due to a disability, please contact JoAnn Pittman (see Contact) at least 7 days in advance.

*Registration Form Instructions*: To register, please complete the registration form in this document and submit to '' Food and Drug Administration, Attn: Dan Redditt, 60 8th St., NE.. Atlanta, GA 30309.'' We encourage you to fax the completed registration form to: 404–253–2257 or 404–253–1202. To obtain a copy of the registration form, please contact: Dan Redditt at 404–253–1265 or via e-mail at *joseph.redditt@fda.hhs.gov*.

FOOD SAFETY AND DEFENSE . . . BE ALERT! PUBLIC WORKSHOP REGISTRATION FORM

Name:

Affiliation:

Mailing Address:

City/State/Zip Code:

Phone:

Fax:

E-mail:

Special Accommodations Required:

*Transcripts*: Transcripts of the public workshop will not be available due to the format of this workshop. Workshop handouts may be requested at cost through the Freedom of Information Office (HFI–35), Food and Drug Administration, 5600 Fishers Lane, rm. 12A–16, Rockville, MD 20857, approximately 15 working days after the public workshop at a cost of 10 cents per page.

**SUPPLEMENTARY INFORMATION:** This public workshop is being held in response to the large volume of food safety and food defense concerns from FDA-regulated products in facilities, such as manufacturers, processors, distributors, retailers, and restaurants, originating from the area covered by the FDA, Atlanta District, Southeast Region. The Atlanta District, Southeast Region presents this workshop to help achieve objectives set forth in section 406 of the Food and Drug Administration Modernization Act of 1997 (21 U.S.C. 393), which include working closely with stakeholders and maximizing the availability and clarity of information to stakeholders and the public. This is consistent with the purposes of the Retail Food Specialists and Public Affairs Specialists, which are in part to respond to industry inquiries, develop educational materials, sponsor workshops and conferences to provide firms, particularly small businesses, with firsthand working knowledge of FDA's guidance, requirements, and compliance policies. This workshop is also consistent with the Small Business Regulatory Enforcement Fairness Act of 1996 (Public Law 104–121) as outreach activities by Government agencies to small businesses.

The purpose of this workshop is to increase the knowledge of operators of small, independent, retail and food service establishments relative to food safety and food defense principles and to increase the application of these principles in their respective operations. The workshop will also present information that will enable food facilities, manufacturers, processors, distributors, retailers, and restaurants, to better comply with the regulations authorized by the Public Health Security and Bioterrorism Preparedness and Response Act of 2002 (the Bioterrorism Act), and with food safety and food defense guidance, especially in light of growing concerns about food defense. Information presented will be based on the agency position as articulated through regulation, guidance, and information previously made available to the public. Topics to be discussed at the workshop include: (1) Pre-Workshop Assessment, (2) The Headline You Don't Want to Make, (3) Tools for Keeping Your Food Safe—Interactive Demonstrations, (4) Be A.L.E.R.T. to Terrorism: Keeping Your Foods Secure, and (5) Making the Commitment (Post-Workshop Assessment), and Q and A.

FDA expects that participation in this public workshop will provide industry with greater understanding of the regulatory and guidance perspectives on food safety and food defense and increase voluntary compliance and food defense awareness.

Dated: July 16, 2007.

**Jeffrey Shuren,**

*Assistant Commissioner for Policy.*

[FR Doc. E7–14045 Filed 7–19 –07; 8:45 am]

**BILLING CODE 4160–01–S**

## DEPARTMENT OF HEALTH AND HUMAN SERVICES

### Indian Health Service

### Office of Urban Indian Health Programs

*Announcement Type:* Competitive Supplemental Grant Announcement.

*Funding Opportunity Number:* HHS–2007–IHS–UIHP–0001.

*Catalog of Federal Domestic Assistance Number:* 93.193.

**Note:** This funding opportunity has been amended to provide additional funds to support the supplemental competitive 4-in-1 Title V grants. The estimated total award amount increased from $316,000 to $350,000. Seven grant supplements will be issued under this announcement. As a result of the notice of amendment, the application deadline date has been revised to allow applicants at least 30 days to apply for the opportunity. The new application deadline date is August 20, 2007. This amendment supersedes the **Federal Register** Notice that was issued July 11, 2007, FR Doc. 07–3359.

*Key Dates: Application Deadline Date:* August 20, 2007. *Review Date:* August 23, 2007. *Earliest Anticipated Start Date:* August 31, 2007.

**I. Funding Opportunity Description**

The Indian Health Service (IHS), Office of Urban Indian Health Programs (OUIHP) announces competitive 4-in-1 Title V grant supplements responding to an Office of Minority Health, HIV/AIDS Initiative. This program is authorized under the authority of the Snyder Act and 25 U.S.C. 1652, 1653 of the Indian Health Care Improvement Act, Public Law 94–437, as amended. This program is described at 93.193 in the Catalog of Federal Domestic Assistance (CFDA).

This competitive supplement seeks to expand OUIHP's existing Title V grants to increase the number of American Indian/Alaska Native (AI/AN) with the awareness of his/her HIV status. This will provide routine and/or rapid HIV screening, prevention, pre and post test counseling, case management (if available) and data collection. Enhancement of urban Indian health program HIV/AIDS activities is necessary to reduce the incidence of HIV/AIDS in the urban Indian health communities.

The purpose of the announcement is to respond to the fact that communities of color have been disproportionately affected by HIV and the need exists for access to early testing, diagnosis, treatment and prevention services. Over the past decade, the AI/AN community has developed and maintained a higher rate of HIV than Caucasians. It has also been demonstrated that AI/ANs have a decreased longevity once diagnosed compared to other races/ethnicities. These supplements will be used to enhance HIV testing, including rapid testing and/or standard HIV antibody testing and to provide a more focused effort to address HIV/AIDS prevention targeting some of the largest urban Indian populations in the United States.

The nature of these projects will require collaboration with the OUIHP to: (1) Coordinate activities; (2) participate in projects in other operating divisions of the Department such as CDC, SAMHSA, HRSA and the Office of Minority Health; and (3) submit and share data on HIV/AIDS testing, treatment and education.

**II. Award Information**

*Type of Award:* Title V Grant Supplements.

*Estimated Funds Available:* The total amount identified for Fiscal Year (FY) 2007 is seven supplement awards totaling $350,000. The award is for one year in duration and the average award, per program is approximately $50,000. Awards under this announcement are subject to the availability of funds.

*Anticipated Number of Awards:* Seven grant supplements will be made under the Program.

*Project Period:* April 1, 2007—March 31, 2008.

*Award Amount:* $350,000.

*A. Requirements of Recipient Activities*

In FY 2007 each grantee's attempted goal shall include screening as many individuals as possible; however, increasing screening 10% or to a minimum of 200 American Indians/Alaska Natives (AI/AN) tested per program funded—adjusted due to variations in size of facility and user population may be required. This does not include counts of re-testing individuals in the same year. Each program shall also collect evidence, as part of the testing process, to potentially address utility and barriers of increased routine HIV screening within this population.

**III. Eligibility Information**

1. *Eligible Applicants:* Urban Indian organizations, as defined by 25 U.S.C. 1603(h), limited to Urban Indian organizations which meet the following criteria:

a. Received State certification to conduct HIV rapid testing;

b. Health professionals and staff have been trained in the HIV/AIDS screening tools, education, prevention, counseling, and other interventions for American Indians/Alaskan Natives;

c. Attuned to the risk factors driving the HIV/AIDS epidemics among urban American Indians/Alaskan Natives;

d. Developed programs to address community and group support to sustain risk-reduction skills;

e. Implemented HIV/AIDS quality assurance and improvement programs; and

f. Must provide proof of non-profit status with the application.

2. Cost Sharing or Matching: This program does not require matching funds or cost sharing.

3. If the application budget exceeds $50,000 it will not be considered for review.

**IV. Application and Submission Information**

1. Applicant package may be found in *Grants.gov* (*www.grants.gov*) or at: *http://www.ihs.gov/NonMedicalPrograms/gogp/gogp_funding.asp.*

Information regarding the electronic application process may be directed to Michelle G. Bulls at (301) 443–6290.

2. Content and Form of Application Submission:

- Be single spaced.
- Be typewritten.
- Have consecutively numbered pages.
- Use black type not smaller than 12 characters per one inch.
- Contain a narrative that does not exceed 25 typed pages that includes the other submission requirements below. The 25 page narrative does not include the work plan, standard forms, table of contents, budget, budget justifications, narratives, and/or other appendix items.

Public Policy Requirements: All Federal-wide public policies apply to IHS grants with the exception of the Lobbying and Discrimination public policy.

3. Submission Dates and Times: The application from each Urban Indian organization must be submitted electronically through *Grants.gov* by 12 midnight Eastern Standard Time (EST).

If technical challenges arise and the urban Indian organizations are unable to successfully complete the electronic application process, each organization must contact Michelle G. Bulls, Grants Policy Staff fifteen days prior to the application deadline and advise of the difficulties that they are experiencing. Each organization must obtain prior approval, in writing (e-mails are acceptable), from Ms. Bulls allowing the paper submission. If submission of a paper application is requested and approved, the original and two copies may be sent to the appropriate grants contact that is listed in Section IV.1 above. Applications not submitted through *Grants.gov*, without an approved waiver, may be returned to the organizations without review or consideration.

A late application will be returned to the organization without review or consideration.

4. Intergovernmental Review: Executive Order 12372 requiring intergovernmental review is not applicable to this program.

5. Funding Restrictions:

A. Pre-award costs are allowable pending prior approval from the awarding agency. However, in accordance with 45 CFR part 74, all pre-award costs are incurred at the recipient's risk. The awarding office is under no obligation to reimburse such costs if for any reason any of the Urban Indian organizations do not receive an award or if the award to the recipient is less than anticipated.

B. The available funds are inclusive of direct and appropriate indirect costs.

C. Only one grant supplement will be awarded to each organization.

D. IHS will acknowledge receipt of the application.

6. Other Submission Requirements:

Electronic Submission—Each Urban Indian organization must submit through *Grants.gov.* However, should any technical challenges arise regarding the submission, please contact *Grants.gov* Customer Support at 1–800–518–4726 or *support@grants.gov*. The Contact Center hours of operation are Monday–Friday from 7 a.m. to 9 p.m. EST. If you require additional assistance please call (301) 443–6290 and identify the need for assistance regarding your *Grants.gov* application. Your call will be transferred to the appropriate grants staff member. Each organization must seek assistance at least fifteen days prior to the application deadline. If each organization doesn't adhere to the timelines for Central Contractor Registry (CCR), *Grants.gov* registration and request timely assistance with technical issues paper application submission may not be granted.

To submit an application electronically, please use the *Grants.gov* Web site. Download a copy of the application package on the *Grants.gov* Web site, complete it offline and then upload and submit the application via the *Grants.gov* site. You may not e-mail an electronic copy of a grant application to IHS.

Please be reminded of the following:

- Under the new IHS application submission requirements, paper applications are not the preferred method. However, if any Urban Indian organization has technical problems submitting the application on-line, please directly contact *Grants.gov* Customer Support at: *http://www.grants.gov/CustomerSupport.*
- Upon contacting *Grants.gov*, obtain a *Grants.gov* tracking number as proof of contact. The tracking number is helpful if there are technical issues that cannot be resolved and a waiver request from Grants Policy must be obtained. If any of the organizations are still unable to successfully submit the application on-line, please contact Michelle G. Bulls, Grants Policy Staff at (301) 443–6290 at least fifteen days prior to the application deadline to advise her of the difficulties you have experienced.
- If it is determined that a formal waiver is necessary, each organization must submit a request, in writing (e-mails are acceptable), to *Michelle.Bulls@ihs.gov* providing a justification for the need to deviate from the standard electronic submission process. Upon receipt of approval, a hard-copy application package must be downloaded from *Grants.gov*, and sent directly to the Division of Grants Operations (DGO), 801 Thompson Avenue, TMP 360, Rockville, MD 20852 by August 20, 2007.
- Upon entering the *Grants.gov* Web site, there is information available that outlines the requirements to each Urban Indian organization regarding electronic submission of application and hours of operation. We strongly encourage that each organization does not wait until the deadline date to begin the application process as the registration process for CCR and *Grants.gov* could take up to fifteen working days.
- To use *Grants.gov,* each Urban Indian organization must have a Dun and Bradstreet (DUNS) Number and register in the CCR. Each organization should allow a minimum of ten working days to complete CCR registration. See below on how to apply.
- Each organization must submit all documents electronically, including all information typically included on the SF–424 and all necessary assurances and certifications.
- Please use the optional attachment feature in *Grants.gov* to attach additional documentation that may be requested by IHS.
- Each organization must comply with any page limitation requirements described in the program announcement.
- After you electronically submit your application, you will receive an automatic acknowledgment from *Grants.gov* that contains a *Grants.gov* tracking number. The DGO will retrieve your application from *Grants.gov.* The DGO will notify each organization that the application has been received.
- You may access the electronic application for this program on *Grants.gov.*
- You may search for the downloadable application package using either the CFDA number or the Funding Opportunity Number. Both numbers are identified in the heading of this announcement.
- To receive an application package, each Urban Indian organization must provide the Funding Opportunity Number: HHS–2007–IHS–UIHP–0001.

E-mail applications will not be accepted under this announcement.

*DUNS Number*

Applicants are required to have a DUNS number to apply for a grant or cooperative agreement from the Federal Government. The DUNS number is a nine-digit identification number, which uniquely identifies business entities. Obtaining a DUNS number is easy and there is no charge. To obtain a DUNS number, access *http://www.dunandbradstreet.com* or call 1–866–705–5711. Interested parties may wish to obtain their DUNS number by phone to expedite the process.

Applications submitted electronically must also be registered with the CCR. A DUNS number is required before CCR registration can be completed. Many organizations may already have a DUNS number. Please use the number listed above to investigate whether or not your organization has a DUNS number. Registration with the CCR is free of charge.

Applicants may register by calling 1–888–227–2423. Please review and complete the CCR Registration Worksheet located on *http://www.grants.gov/CCR* Register.

More detailed information regarding these registration processes can be found at *Grants.gov.*

**V. Application Review Information**

*1. Criteria*

The instructions for preparing the application narrative also constitute the evaluation criteria for reviewing and scoring the application. Weights assigned to each section are noted in parentheses. The narrative should include the first year of activities;

information for multi-year projects should be included as an appendix (see E. ''Categorical Budget and Budget Justification'') at the end of this section for more information. The narrative should be written in a manner that is clear to outside reviewers unfamiliar with prior related activities of the Urban Indian organization. It should be well organized, succinct, and contain all information necessary for reviewers to understand the project fully.

A. Understanding of the Need and Necessary Capacity (30 Points)

1. Understanding of the Problem

a. Define the project target population, identify their unique characteristics, and describe the impact of HIV on the population.

b. Describe the gaps/barriers in HIV testing for the population.

c. Describe the unique cultural or sociological barriers of the target population to adequate access for the described services.

2. Facility Capability

a. Briefly describe your clinic programs and services and how this initiative complements and/or expands existing efforts.

b. Describe your clinic's ability to conduct this initiative through:

• Your clinic's own resources.

• Describe collaboration with other providers.

• Identify and describe partnerships established to accept referrals for counseling, testing, and referral and confirmatory blood tests and/or social services for individuals who test HIV positive.

• Identify and describe partnerships established to refer out of your clinic for specialized treatment, care, confirmatory testing (if applicable) and counseling services.

B. Work Plan (40 Points)

1. Project Goal and Objectives

Address all of the following program goals and objectives of the project. The objectives must be specific as well as quantitatively and qualitatively measurable to ensure achievement of goal(s).

• President's Initiative for HIV/AIDS

Explain how the continuation program addresses the President's Initiative for HIV/AIDS objective requiring testing of those who do not know their status. For a more direct and relevant program initiative, this proposal will be enumerated in the development of the new IHS HIV/AIDS Strategic Plan.

• HHS Strategic Plan Support

Describe how implementing, expanding and making routine HIV/AIDS direct service opportunities in your clinic ensures an innovative approach towards achievement of two most critical HHS Strategic Plan Objectives relative to the health status of AI/AN:

Objective 3.4—Eliminate racial and ethnic health disparities

Objective 3.6—Increase access to health services for AI/AN

• Office of the Secretary Minority AIDS Initiative

Address how the Minority AIDS Initiative Goals/Objectives will be supported. If a goal/objective is not applicable to your program, explain why it is not applicable. Provide quantitative and qualitative objectives for each of the following.

1. Expand Services

a. Increase the number of clients receiving services;

b. Increase the number of clients that receive an HIV test and are provided results and know their status; and

c. Increase the number of clients treated and/or referred into the system for medical care.

2. Build Capacity

a. Identify the number of providers that have expanded their:

• Knowledge of HIV screening methods;

• Knowledge of streamlining procedures; and

• Collaboration with outside entities such as CDC, HRSA, and/or State health departments.

3. Best Practices Models

a. Identify best practice models of implementation of expanded services.

4. Enumerate lessons observed and address barriers to care.

• IHS Strategic Plan Support

Describe how this project integrates with the IHS Strategic Plan which includes concepts surrounding:

1. Building and sustaining healthy communities

2. Providing accessible, quality health care, and

3. Fostering collaboration and innovation across the Indian health network.

• IHS HIV/AIDS Administrative Work Plan Goals

Describe how the IHS HIV/AIDS Administrative work plan goals will be supported. If a goal is not applicable to your program, explain why it is not applicable.

1. Assist AI/AN in becoming aware of serostatus;

2. Reduce the transmission of HIV through behavior change, prevention education and open discussion;

3. Ensure access (and linkages) to services for those living with HIV/AIDS and those at risk;

4. Make routine HIV/AIDS services and ensure quality HIV/AIDS care is delivered within the Indian health system;

5. Reduce stigma and discrimination surrounding HIV/AIDS; and

6. Form sustainable collaborations and integrative approaches (i.e. STD and HIV integration) to build capacity and maximize resources for surveillance, prevention, treatment and mitigation.

• Implementation Plan

1. Identify the proposed program activities and explain how these activities will meet the needs of the target population.

2. Describe any anticipated outcomes that may be achieved from this project plan.

3. Provide a timeline for implementation.

4. Has the program identified and agreed to follow the State regulations for HIV testing in their state?

5. How will individuals be selected for testing to identify selection criteria and which group(s)—if any—will you be able, via State regulations, to offer testing in an opt-out format?

6. How will you ensure that clients receive their test results, particularly clients who test positive?

7. How will you ensure that individuals with initial HIV-positive test results will receive confirmatory tests? If you do not provide confirmatory HIV testing, you must provide a letter of intent or MOA with an external laboratory documenting the process through which initial HIV-positive test results will be confirmed.

8. What are your strategies to linking potential seropositive patients to care?

9. What are your quality assurance strategies?

10. How will you train, support and retain staff providing counseling and testing?

11. How will you ensure client confidentiality?

12. How will you ensure that your services are culturally sensitive and relevant?

• Staffing Plan

Describe the existing or proposed positions to be funded and provide names and roles of the key position(s) carrying out this project, their qualifications and how they relate to the organizations, with regard to supervision and quality control.

C. Project Evaluation (10 Points)

1. Evaluation Plan

The grantee shall provide a plan for monitoring and evaluating the HIV rapid test and/or standard HIV antibody test.

2. Reporting Requirements

The following quantitative and qualitative measures shall be addressed:

- Indicators (quantitative)

1. Number of tests offered and number of test refusals
2. Number of clients who refused due to prior knowledge of status
3. Number of individuals tested with breakdown of rapid versus standard antibody test
4. Number of negative results
5. Number of false negatives and/or false positives after confirmatory testing
6. Number of reactive tests and confirmed seropositive (actual and proportion)
7. Number of individuals receiving their confirmatory test results
8. Number of clients linked to care/treatment or referrals for prevention counseling
9. Number of post-test counseling sessions
10. Number of pre-test counseling sessions (brief)
11. Number of prevention counseling sessions (more depth) due to higher risk populations
12. Number of missed follow up after rapid test is reactive
13. Transmission category (if known)
14. Measures in place to protect confidentiality

- Qualitative Information

1. Identify Testing Methodology

a. Will testing be rapid or standard?

b. Opt-out format should be utilized. Unless otherwise determined by State regulations—please explain.

c. Is your methodology based on risk-based screening? Based on what risk criteria? Are you offering more routine screening? What are the criteria for offering tests if any?

2. Identify barriers of implementation

- Plan for obtaining knowledge, attitudes, and behavior data.

D. Organizational Capabilities and Qualifications (10 Points)

This section outlines the broader capacity of the organization to complete the project outlined in the work plan. It includes the identification of personnel responsible for completing tasks and the chain of responsibility for successful completion of the project outlined in the work plan.

1. Describe the organizational structure.
2. Describe the ability of the organization to manage the proposed project. Include information regarding similarly sized projects in scope and financial assistance as well as other grants and projects successfully completed.
3. Describe what equipment (i.e., phone, websites, etc.) and facility space (i.e., office space) will be available for use during the proposed project. Include information about any equipment not currently available that will be purchased throughout the agreement.
4. List key personnel who will work on the project.

- Identify existing personnel and new program staff to be hired.
- In the appendix, include position descriptions and resumes for all key personnel. Position descriptions should clearly describe each position and duties indicating desired qualifications, experience, and requirements related to the proposed project and how they will be supervised. Resumes must indicate that the proposed staff member is qualified to carry out the proposed project activities and who will determine if the work of a contractor is acceptable.
- Note who will be writing the progress reports.
- If a position is to be filled, indicate that information on the proposed position description.
- If the project requires additional personnel beyond those covered by the supplemental grant (i.e., IT support, volunteers, interviewers, etc.), note these and address how these positions will be filled and, if funds are required, the source of these funds.
- If personnel are to be only partially funded by this supplemental grant, indicate the percentage of time to be allocated to this project and identify the resources used to fund the remainder of the individual's salary.

E. Categorical Budget and Budget Justification (10 Points)

This section should provide a clear estimate of the project program costs and justification for expenses for the entire grant period. The budget and budget justification should be consistent with the tasks identified in the work plan.

1. Categorical budget (Form SF 424A, Budget Information Non-Construction Programs) completing each of the budget periods requested.
2. Narrative justification for all costs, explaining why each line item is necessary or relevant to the proposed project. Include sufficient details to facilitate the determination of cost allowability.
3. Budget justification should include a brief program narrative for the second and third years.
4. If indirect costs are claimed, indicate and apply the current negotiated rate to the budget. Include a copy of the rate agreement in the appendix.

*2. Review and Selection Process*

In addition to the above criteria/requirements, the application will be considered according to the following:

A. The submission deadline: August 20, 2007. The application submitted in advance of or by the deadline and verified by the postmark will undergo a preliminary review to determine that:

- The applicant is eligible in accordance with this grant announcement.
- The application is not a duplication of a previously funded project.
- The application narrative, forms, and materials submitted meet the requirements of the announcement allowing the review panel to undertake an in-depth evaluation; otherwise, it may be returned.

B. The Objective Review date is August 23, 2007.

The application requirements that are complete, responsive, and conform to this program announcement will be reviewed for merit by the Ad Hoc Objective Review Committee (ORC) appointed by the IHS to review and make recommendations on this application. Prior to ORC review, the application will be screened to determine that programs proposed are those which the IHS has the authority to provide, either directly or through funding agreement, and that those programs are designed for the benefit of IHS beneficiaries. If an Urban Indian organization does not meet these requirements, the application will not be reviewed. The ORC review will be conducted in accordance with the IHS Objective Review Guidelines. The application will be evaluated and rated on the basis of the evaluation criteria listed in section V.1. The criteria are used to evaluate the quality of a proposed project and determine the likelihood of success.

*3. Anticipated Announcement and Award Dates*

Anticipated announcement date is August 20, 2007 with an Award Date of August 24, 2007.

## VI. Award Administration Information

*1. Award Notices*

The Notice of Award (NoA) will be initiated by the DGO and will be mailed via postal mail to the Urban Indian organization. The NoA will be signed by the Grants Management Officer and this is the authorizing document under which funds are dispersed. The NoA, is the legally binding document, will serve as the official notification of the grant award and will reflect the amount of Federal funds awarded for the purpose of the grant, the terms and conditions of the award, the effective date of the award, and the budget/project period.

*2. Administrative Requirements*

Grants are administered in accordance with the following documents:

- This Program Announcement.
- 45 CFR Part 74, ''Uniform Administrative Requirements for Awards to Institutions of Higher Education, Hospitals, Other Non-Profit Organizations, and Commercial Organizations.''
- Grants Policy Guidance: HHS Grants Policy Statement, January 2007.
- ''Non-Profit Organizations'' (Title 2 Part 230).
- Audit Requirements: OMB Circular A–133, ''Audits of States, Local Governments, and Non-Profit Organizations.''

*3. Indirect Costs*

This section applies to indirect costs in accordance with HHS Grants Policy Statement, Part II–27, IHS requires applicants to have a current indirect cost rate agreement in place prior to award. The rate agreement must be prepared in accordance with the applicable cost principles and guidance as provided by the cognizant agency or office. A current rate means the rate covering the applicable activities and the award budget period. If the current rate is not on file with the awarding office, the award shall include funds for reimbursement of indirect costs. However, the indirect costs portion will remain restricted until the current rate is provided to DGO.

If an Urban Indian organization has questions regarding the indirect costs policy, please contact the DGO at (301) 443–5204.

*4. Reporting*

A. Progress Report. Program progress reports are required semi-annually. These reports will include a brief comparison of actual accomplishments to the goals established for the period, reasons for slippage (if applicable), and other pertinent information as required. A final report must be submitted within 90 days of expiration of the budget/project period.

B. Financial Status Report. Semi-annual financial status reports must be submitted within 30 days of the end of the half year. Final financial status reports are due within 90 days of expiration of the budget period. Standard Form 269 (long form) will be used for financial reporting.

Failure to submit required reports within the time allowed may result in suspension or termination of an active agreement, withholding of additional awards for the project, or other enforcement actions such as withholding of payments or converting to the reimbursement method of payment. Continued failure to submit required reports may result in one or both of the following: (1) The imposition of special award provisions; and (2) the non-funding or non-award of other eligible projects or activities. This applies whether the delinquency is attributable to the failure of the organization or the individual responsible for preparation of the reports.

Telecommunication for the hearing impaired is available at: TTY 301–443–6394.

## VII. Agency Contacts

For program-related information: Phyllis S. Wolfe, Director, Office of Urban Indian Health Programs, 801 Thompson Avenue, Suite 200, Rockville, Maryland 20852, (301) 443–4680 or *phyllis.wolfe@ihs.gov.*

For general information regarding this announcement: Danielle Steward, Health Systems Specialist, Office of Urban Indian Health Programs, 801 Thompson Road, Room 200, Rockville, MD 20852, (301) 443–4680 or *danielle.steward@ihs.gov.*

For specific grant-related and business management information: Denise Clark, Senior Grants Management Specialist, 801 Thompson Avenue, TMP 360, Rockville, MD 20852, 301–443–5204 or *denise.clark@ihs.gov.*

## VIII. Other Information

None.

Dated: July 16, 2007.

**Robert G. McSwain,**

*Deputy Director, Indian Health Service.*

[FR Doc. E7–14033 Filed 7–19–07; 8:45 am]

BILLING CODE 4165–16–P

---

## DEPARTMENT OF HEALTH AND HUMAN SERVICES

### National Institutes of Health

### Government-Owned Inventions; Availability for Licensing

**AGENCY:** National Institutes of Health, Public Health Service, HHS.

**ACTION:** Notice.

---

**SUMMARY:** The inventions listed below are owned by an agency of the U.S. Government and are available for licensing in the U.S. in accordance with 35 U.S.C. 207 to achieve expeditious commercialization of results of federally-funded research and development. Foreign patent applications are filed on selected inventions to extend market coverage for companies and may also be available for licensing.

**ADDRESSES:** Licensing information and copies of the U.S. patent applications listed below may be obtained by writing to the indicated licensing contact at the Office of Technology Transfer, National Institutes of Health, 6011 Executive Boulevard, Suite 325, Rockville, Maryland 20852–3804; telephone: 301/496–7057; fax: 301/402–0220. A signed Confidential Disclosure Agreement will be required to receive copies of the patent applications.

### Photosensitization by Nuclear Receptor-Ligand Complexes and Cell Ablation Uses Thereof

*Description of Technology:* Androgen receptors (AR) mediate the effects of male steroid hormones and contribute to a wide variety of physiological and pathophysiological conditions. Prostate cancer development and progression are mediated through AR, a ligand-dependent transcription factor, and it is present in all stages of prostate carcinoma. Increased levels of PSA, an AR-induced prostate tumor-specific protein, are indicative of prostate cancer. Benign, non-cancerous conditions are also AR-dependent and can be therapeutic targets as well.

This technology is a method to cause AR-induced cell death (apoptosis) through photoactivation of a non-steroidal androgen receptor antagonist 1,2,3,4-tetrahydro-2,2-dimethyl-6-(trifluoromethyl)-8-pyridono[5,6-g] quinoline (TDPQ). Upon TDPQ binding to AR, a highly potent photocytoxic reaction induced once the TDPQ–AR complex is exposed to visible light irradiation of a specific wavelength. The inventors have cell-culture results demonstrating that cell death is a function of TDPQ, AR and light irradiation. This treatment method can potentially target AR-containing cancerous cells, while sparing nearby cells that lack AR.

The process has been extended to other nuclear receptors by choice of other photoactivatable ligands for these receptors. Certain suitable ligands are marketed drugs.

*Applications:* Therapeutic compounds to treat AR related conditions such as prostate cancer, baldness, hirsutism, and acne; Potential therapeutics for progesterone and glucocorticoid receptor ligand related conditions such as breast and brain cancers, lymphoma, leukemia and arthritis; Method to treat androgen, progesterone, and glucorticoid receptor related conditions.

*Market:* Prostate cancer is the second most common type of cancer among men, wherein one in six men will be diagnosed with prostate cancer; An estimated 218,890 new cases of prostate cancer and 27,050 deaths due to prostate cancer in the U.S. in 2007; Hirsutism affects approximately 5% of adult women in the United States; Hair loss and acne industries are worth several billions of dollars.

*Development Status:* The technology is currently in the pre-clinical stage of development.

*Inventors:* William T. Schrader *et al.* (NIEHS).

*Publications:*

1. B Risek *et al.* Androgen Receptor-Mediated Apoptosis is Regulated by Photoactivatable AR Ligands. Abstract submitted to the Endocrine Society; To be presented at the Annual Meeting of the Endocrine Society in Toronto, Canada in June 2007.

2. B Risek *et al.* Photocytotoxic Properties of the Non-Steroidal Androgen Receptor Antagonist TDPQ. Presented at the Annual Meeting of the Endocrine Society in Boston, MA in June 2006.

*Patent Status:* U.S. Provisional Application No. 60/926,218 filed 24 Apr 2007 (HHS Reference No. E–108–2007/0–US–01).

*Licensing Status:* Available for exclusive or non-exclusive licensing.

*Licensing Contact:* Jennifer Wong; 301/435–4633; *wongje@mail.nih.gov.*

**Method of Treating or Preventing Oxidative Stress-Related Diseases (Stroke and Neurodegenerative Diseases, Wound Healing and Cardiovascular Diseases)**

*Description of Technology:* Reactive oxygen species (ROS) and reactive nitrogen species (RNS) produce oxidative stress to DNA, lipids and proteins thus causing cellular and tissue damage. A number of diseases are associated with oxidative stress including Alzheimer's disease, ischemic stroke, heart disease, cancer, hepatitis, and autoimmune disease. Uric acid is a natural antioxidant effective in reducing ROS and research has shown that uric acid contributes approximately two-thirds of all free radical scavenging capacity in plasma. Because uric oxide is too insoluble to be used as a therapeutic agent, scientists at the NIH developed uric acid analogs with improved anti-oxidative and solubility properties for use as free radical scavengers or antioxidants. These analogs increased survival of PC12 and hippocampal neurons after challenge by Fe, MPP and Glutamate. When administered to a mouse model of focal ischemic stroke, these compounds protect neuronal cells from ROS and reduce brain damage and ameliorate neurological deficits. Other studies show a single application of these analogs on skin lacerations in mice decreased the time for wound repair. Available for licensing are methods of treating ischemic stroke and wound healing, and for the prevention or treatment of other oxidative stress-related diseases, such as epilepsy, Parkinson's disease and dementia.

*Applications*: Novel uric acid analogs for use as antioxidants to help reduce the risk of stroke, neurological diseases and assisting with wound repair.

*Market:* Stroke is the third-leading cause of death and the leading cause of severe neurological disability worldwide; Americans will pay approximately $62.7 billion dollars in 2007 for stroke-related medical costs and disability.

*Development Status:* Pre-clinical data.

*Inventors:* Nigel H. Greig (NIA), Mark P. Mattson (NIA), *et al.*

*Patent Status:* U.S. Provisional Application No. 60/839,800 filed 23 Aug 2006 (HHS Reference No. E–059–2006/0–US–01).

*Licensing Status:* Available for licensing.

*Licensing Contact:* Norbert Pontzer, PhD, J.D.; 301/435–5502; *pontzern@mail.nih.gov.*

*Collaborative Research Opportunity:* The National Institute on Aging, Laboratory of Neurosciences, is seeking statements of capability or interest from parties interested in collaborative research to further develop, evaluate, or commercialize the described uric acid analogue technology in the treatment of neurodegenerative diseases, wound healing and cardiovascular disease. Please contact John D. Hewes, PhD at 301–435–3121 or *hewesj@mail.nih.gov* for more information.

**Thiazepine Inhibitors of HIV–1 Integrase**

*Description of Technology:* The human immunodeficiency virus (HIV) is the causative agent of acquired immunodeficiency syndrome (AIDS). Drug resistance is a critical factor contributing to the gradual loss of clinical benefit of treatments for HIV infection. Accordingly, combination therapies have further evolved to address the mutating resistance of HIV. However, there has been great concern regarding the apparent growing resistance of HIV strains to current therapies.

It has been found that a certain class of compounds including thiazepines and analogs and derivatives thereof are effective and selective anti-integrase inhibitors. These compounds have been found to inhibit both viral replication and the activity of purified HIV–1 integrase. The subject invention provides for such compounds and for methods of inhibiting HIV integrase.

*Inventors:* Yves Pommier *et al.* (NCI).

*Patent Status:* U.S. Patent No. 7,015,212 issued 21 Mar 2006 (HHS Reference No. E–036–1999/0–US–03).

*Licensing Status:* Available for exclusive or non-exclusive licensing.

*Licensing Contact:* Sally Hu, PhD, MBA; 301/435–5606; *hus@mail.nih.gov.*

*Collaborative Research Opportunity:* The Laboratory of Molecular Pharmacology of the National Cancer Institute is seeking statements of capability or interest from parties interested in collaborative research to further develop, evaluate, or commercialize anti-integrase inhibitors. Please contact John D. Hewes, PhD at 301–435–3121 or *hewesj@mail.nih.gov* for more information.

Dated: July 13, 2007.

**Steven M. Ferguson,**

*Director, Division of Technology Development and Transfer, Office of Technology Transfer, National Institutes of Health.*

[FR Doc. E7–14031 Filed 7–19–07; 8:45 am]

BILLING CODE 4140–01–P

## DEPARTMENT OF HEALTH AND HUMAN SERVICES

### National Institutes of Health

### National Eye Institute; Notice of Closed Meeting

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. Appendix 2), notice is hereby given of the following meeting.

The meeting will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

*Name of Committee:* National Eye Institute Special Emphasis Panel, NEI Clinical Applications II.

*Date:* July 25, 2007.

*Time:* 10:30 a.m. to 11:15 a.m.

*Agenda:* To review and evaluate grant applications.

*Place:* National Eye Institute, 5635 Fishers Lane, Bethesda, MD 20892 (Telephone Conference Call).

*Contact Person:* Anne E Schaffner, PhD, Scientific Review Administrator, Division of Extramural Research, National Eye Institute, 5635 Fishers Lane, Suite 1300, MSC 9300, Bethesda, MD 20892-9300, (301) 451–2020, *aes@nei.nih.gov*.

This notice is being published less than 15 days prior to the meeting due to the timing limitations imposed by the review and funding cycle.

(Catalogue of Federal Domestic Assistance Program Nos. 93.867, Vision Research, National Institutes of Health, HHS)

Dated: July 12, 2007.

**Jennifer Spaeth,**

*Director, Office of Federal Advisory Committee Policy.*

[FR Doc. 07–3523 Filed 7–19–07; 8:45 am]

**BILLING CODE 4140–01–M**

---

## DEPARTMENT OF HEALTH AND HUMAN SERVICES

### National Institutes of Health

### National Institute of Allergy and Infectious Diseases; Notice of Closed Meeting

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. Appendix 2), notice is hereby given of the following meeting.

The meeting will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The contract proposals and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the contract proposals, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

*Name of Committee:* National Institute of Allergy and Infectious Diseases Special Emphasis Panel, NIH Tetramer Facility.

*Date:* August 1, 2007.

*Time:* 1 p.m. to 4 p.m.

*Agenda:* To review and evaluate contract proposals.

*Place:* National Institutes of Health, Rockledge 6700, 6700B Rockledge Drive, Bethesda, MD 20817.

*Contact Person:* Alex Ritchie, PhD, Scientific Review Administrator, DHHS/NIH/NIAID/DEA Scientific Review Program, 6700B Rockledge Drive MSC 7616, Room 3123, Bethesda, MD 20892, 301–496–2550, *aritchie@niaid.nih.gov.*

This notice is being published less than 15 days prior to the meeting due to the timing limitations imposed by the review and funding cycle.

(Catalogue of Federal Domestic Assistance Program Nos. 93.855, Allergy, Immunology, and Transplantation Research; 93.856, Microbiology And Infectious Diseases Research, National Institutes of Health, HHS)

Dated: July 13, 2007.

**Jennifer Spaeth,**

*Director, Office of Federal Advisory Committee Policy.*

[FR Doc. 07–3522 Filed 7–19–07; 8:45 am]

**BILLING CODE 4140–01–M**

---

## DEPARTMENT OF HEALTH AND HUMAN SERVICES

### National Institutes of Health

### National Institute of Child Health and Human Development; Notice of Closed Meeting

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. Appendix 2), notice is hereby given of the following meeting.

The meeting will be closed to the public in accordance with the provisions set forth in Sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The contract proposals and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the contract proposals, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

*Name of Committee:* National Institute of Child Health and Human Development Special Emphasis Panel, Health Behavior in School-Age Children.

*Date:* August 6, 2007.

*Time:* 8 a.m. to 5 p.m.

*Agenda:* To review and evaluate contract proposals.

*Place:* Hilton Washington/Rockville, Previously Double Tree Hotel, 1750 Rockville Pike, Rockville, MD 20852.

*Contact Person:* Hameed Khan, PhD, Scientific Review Administrator, Division of Scientific Review, National Institute of Child Health and Human Development, NIH, 6100 Executive Blvd., Room 5B01, Bethesda, MD 20892, (301) 435–6902, *Khanh@mail.nih.gov.*

(Catalogue of Federal Domestic Assistance Program Nos. 93.864, Population Research; 93.865, Research for Mothers and Children; 93.929, Center for Medical Rehabilitation Research; 93.309, Contraception and Infertility Loan Repayment Program, National Institutes of Health, HHS)

Dated: July 12, 2007.

**Jennifer Spaeth,**

*Director, Office of Federal Advisory Committee Policy.*

[FR Doc. 07–3526 Filed 7–19–07; 8:45 am]

**BILLING CODE 4140–01–M**

---

## DEPARTMENT OF HEALTH AND HUMAN SERVICES

### National Institutes of Health

### National Institute of Child Health and Human Development; Notice of Closed Meeting

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. Appendix 2), notice is hereby given of the following meeting.

The meeting will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The contract proposals and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the contract proposals, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

*Name of Committee:* National Institute of Child Health and Human Development Special Emphasis Panel, National Standard for Normal Fetal Growth—Part A—Clinical Sites & Part B—Central Sonologist.

*Date:* August 13, 2007.

*Time:* 8 a.m. to 5 p.m.

*Agenda:* To review and evaluate contract proposals.

*Place:* Hilton Washington/Rockville, Double Tree Name Changed, 1750 Rockville Pike, Rockville, MD 20852.

*Contact Person:* Hameed Khan, PhD, Scientific Review Administrator, Division of Scientific Review, National Institute of Child Health and Human Development, NIH, 6100 Executive Blvd., Room 5B01, Bethesda, MD 20892, (301) 435–6902, *khanh@mail.nih.gov.*

(Catalogue of Federal Domestic Assistance Program Nos. 93.864, Population Research; 93.865, Research for Mothers and Children; 93.929, Center for Medical Rehabilitation Research; 93.209, Contraception and Infertility Loan Repayment Program, National Institutes of Health, HHS)

Dated: July 12, 2007.

**Jennifer Spaeth,**

*Director, Office of Federal Advisory Committee Policy.*

[FR Doc. 07–3527 Filed 7–19–07; 8:45 am]

**BILLING CODE 4140–01–M**

---

## DEPARTMENT OF HEALTH AND HUMAN SERVICES

### National Institutes of Health

### National Library of Medicine; Notice of Meeting

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended ( 5 U.S.C. Appendix 2), notice is hereby given of a meeting of the

Board of Scientific Counselors, Lister Hill National Center for Biomedical Communications.

The meeting will be open to the public as indicated below, with attendance limited to space available. Individuals who plan to attend and need special assistance, such as sign language interpretation or other reasonable accommodations, should notify the Contact Person listed below in advance of the meeting.

The meeting will be closed to the public as indicated below in accordance with the provisions set forth in section 552b(c)(6), Title 5 U.S.C., as amended for the review, discussion, and evaluation of individual intramural programs and projects conducted by the National Library of Medicine, including consideration of personnel qualifications and performance, and the competence of individual investigators, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

*Name of Committee:* Board of Scientific Counselors, Lister Hill National Center for Biomedical Communications.

*Date:* September 6–7, 2007.

*Open:* September 6, 2007, 9 a.m. to 12 p.m.

*Agenda:* Review of research and development programs and preparation of reports of the Lister Hill Center for Biomedical Communications.

*Place:* National Library of Medicine, Building 38, Board Room 2nd Floor, 8600 Rockville Pike, Bethesda, MD 20892.

*Closed:* September 6, 2007, 12 p.m. to 5 p.m.

*Agenda:* To review and evaluate personal qualifications and performance, and competence of individual investigators.

*Place:* National Library of Medicine, Building 38, Board Room 2nd Floor, 8600 Rockville Pike, Bethesda, MD 20892.

*Open:* September 7, 2007, 9 a.m. to 11:15 a.m.

*Agenda:* Review of research and development programs and preparation of reports of the Lister Hill Center for Biomedical Communications.

*Place:* National Library of Medicine, Building 38, Board Room 2nd Floor, 8600 Rockville Pike, Bethesda, MD 28092.

*Contact Person:* Karen Steely, Program Assistant, Lister Hill National Center for Biomedical Communications, National Library of Medicine, Building 38A, Room 7S709, Bethesda, MD 20892, 301–435–3137, *ksteely@mail.nih.gov.*

Any interested person may file written comments with the committee by forwarding the statement to the Contact Person listed on this notice. The statement should include the name, address, telephone number and when applicable, the business or professional affiliation of the interested person.

In the interest of security, NIH has instituted stringent procedures for entrance onto the NIH campus. All visitor vehicles, including taxicabs, hotel, and airport shuttles will be inspected before being allowed on campus. Visitors will be asked to show one form of identification (for example, a government-issued photo ID, driver's license, or passport) and to state the purpose of their visit.

(Catalogue of Federal Domestic Assistance Program Nos. 93.879, Medical Library Assistance, National Institutes of Health, HHS)

Dated: July 12, 2007.

**Jennifer Spaeth,**

*Director, Office of Federal Advisory Committee Policy.*

[FR Doc. 07–3528 Filed 7–19–07; 8:45 am]

BILLING CODE 4140–01–M

## DEPARTMENT OF HEALTH AND HUMAN SERVICES

### National Institutes of Health

### Center for Scientific Review; Notice of Closed Meetings

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. Appendix 2), notice is hereby given of the following meetings.

The meetings will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

*Name of Committee:* Center for Scientific Review Special Emphasis Panel, Bacterial Pathogenesis.

*Date:* July 24, 2007.

*Time:* 3 p.m. to 6 p.m.

*Agenda:* To review and evaluate grant applications.

*Place:* National Institutes of Health, 6701 Rockledge Drive, Bethesda, MD 20892 (Telephone Conference Call).

*Contact Person:* Robert Freund, PhD, Scientific Review Administrator, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 3200, MSC 7848, Bethesda, MD 20892, 301–435–1050, *freundr@csr.nih.gov.*

This notice is being published less than 15 days prior to the meeting due to the timing limitations imposed by the review and funding cycle.

*Name of Committee:* Center for Scientific Review Special Emphasis Panel, Protein Synthesis Regulation.

*Date:* July 26, 2007.

*Time:* 1 p.m. to 2 p.m.

*Agenda:* To review and evaluate grant applications.

*Place:* National Institutes of Health, 6701 Rockledge Drive, Bethesda, MD 20892 (Telephone Conference Call).

*Contact Person:* Mary P. McCormick, PhD, Scientific Review Administrator, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 2208, MSC 7890, Bethesda, MD 20892, 301–435–1047, *mccormim@csr.nih.gov.*

This notice is being published less than 15 days prior to the meeting due to the timing limitations imposed by the review and funding cycle.

*Name of Committee:* Center for Scientific Review Special Emphasis Panel, Member Conflict: Reproductive Biology.

*Date:* August 1, 2007.

*Time:* 1 p.m. to 4 p.m.

*Agenda:* To review and evaluate grant applications.

*Place:* National Institutes of Health, 6701 Rockledge Drive, Bethesda, MD 20892 (Telephone Conference Call).

*Contact Person:* Reed A. Graves, PhD, Scientific Review Administrator, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 6166, MSC 7892, Bethesda, MD 20892, 301–402–6297, *gravesr@csr.nih.gov.*

This notice is being published less than 15 days prior to the meeting due to the timing limitations imposed by the review and funding cycle..

*Name of Committee:* Center for Scientific Review Special Emphasis Panel, Eye Transplantation.

*Date:* August 8–9, 2007.

*Time:* 9 a.m. to 9 p.m.

*Agenda:* To review and evaluate grant applications.

*Place:* National Institutes of Health, 6701 Rockledge Drive, Bethesda, MD 20892 (Virtual Meeting).

*Contact Person:* Joanne T. Fujii, PhD, Scientific Review Administrator, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 4184, MSC 7850, Bethesda, MD 20892, 301–435–1178, *fujiij@csr.nih.gov.*

*Name of Committee:* Center for Scientific Review Special Emphasis Panel, Small Business: Dentistry Related.

*Date:* August 16–17, 2007.

*Time:* 9 a.m. to 5 p.m.

*Agenda:* To review and evaluate grant applications.

*Place:* National Institutes of Health, 6701 Rockledge Drive, Bethesda, MD 20892 (Virtual Meeting).

*Contact Person:* J. Terrell Hoffeld, DDS, PhD, Dental Officer, USPHS, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 4116, MSC 7816, Bethesda, MD 20892, 301–435–1781, *th88q@nih.gov.*

(Catalogue of Federal Domestic Assistance Program Nos. 93.306, Comparative Medicine; 93.333, Clinical Research, 93.306, 93.333, 93.337, 93.393–93.396, 93.837–93.844, 93.846–93.878, 93.892, 93.893, National Institutes of Health, HHS)

Dated: July 12, 2007.

**Jennifer Spaeth,**

*Director, Office of Federal Advisory Committee Policy.*

[FR Doc. 07–3524 Filed 7–19–07; 8:45 am]

BILLING CODE 4140–01–M

## DEPARTMENT OF HEALTH AND HUMAN SERVICES

### National Institutes of Health

### Center for Scientific Review; Amended Notice of Meeting

Notice is hereby given of a change in the meeting of the Center for Scientific Review Special Emphasis Panel, June 18, 2007, 8:30 a.m. to June 18, 2007, 6 p.m. The River Inn, 924 25th Street, NW., Washington, DC 20037 which was published in the **Federal Register** on May 22, 2007, 72 FR 28706–28708.

The meeting will be held July 27, 2007, 8:30 a.m. to 6 p.m. at the George Washington University Inn, 824 New Hampshire Avenue, NW., Washington, DC 20037. The meeting is closed to the public.

Dated: July 12, 2007.

**Jennifer Spaeth,**

*Director, Office of Federal Advisory Committee Policy.*

[FR Doc. 07–3525 Filed 7–19–07; 8:45 am]

BILLING CODE 4140–01–M

## DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

**[Docket No. FR–5125–N–29]**

### Federal Property Suitable as Facilities To Assist the Homeless

**AGENCY:** Office of the Assistant Secretary for Community Planning and Development, HUD.

**ACTION:** Notice.

**SUMMARY:** This Notice identifies unutilized, underutilized, excess, and surplus Federal property reviewed by HUD for suitability for possible use to assist the homeless.

**DATES:** *Effective Date:* July 20, 2007.

**FOR FURTHER INFORMATION CONTACT:** Kathy Ezzell, Department of Housing and Urban Development, Room 7262, 451 Seventh Street, SW., Washington, DC 20410; telephone (202) 708–1234; TTY number for the hearing- and speech-impaired (202) 708–2565, (these telephone numbers are not toll-free), or call the toll-free Title V information line at 1–800–927–7588.

**SUPPLEMENTARY INFORMATION:** In accordance with the December 12, 1988 court order in *National Coalition for the Homeless* v. *Veterans Administration*, No. 88–2503–OG (D.D.C.), HUD publishes a Notice, on a weekly basis, identifying unutilized, underutilized, excess and surplus Federal buildings and real property that HUD has reviewed for suitability for use to assist the homeless. Today's Notice is for the purpose of announcing that no additional properties have been determined suitable or unsuitable this week.

Dated: July 16, 2007.

**Mark R. Johnston,**

*Deputy Assistant Secretary, for Special Needs.*

[FR Doc. 07–3521 Filed 7–19–07; 8:45 am]

BILLING CODE 4210–67–M

## DEPARTMENT OF THE INTERIOR

### Fish and Wildlife Service

### Information Collection Sent to the Office of Management and Budget (OMB) for Approval; OMB Control Number 1018–0022; Federal Fish and Wildlife Permit Applications and Reports—Migratory Birds and Eagles

**AGENCY:** Fish and Wildlife Service, Interior.

**ACTION:** Notice; Request for Comments.

**SUMMARY:** We (Fish and Wildlife Service) have sent an Information Collection Request (ICR) to OMB for review and approval. The ICR, which is summarized below, describes the nature of the collection and the estimated burden and cost. This information collection is scheduled to expire on July 31, 2007. We 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. However, under OMB regulations, we may continue to conduct or sponsor this information collection while it is pending at OMB.

**DATES:** You must submit comments on or before August 20, 2007.

**ADDRESSES:** Send your comments and suggestions on this ICR to the Desk Officer for the Department of the Interior at OMB-OIRA at (202) 395–6566 (fax) or OIRA_DOCKET@OMB.eop.gov (e-mail). Please provide a copy of your comments to Hope Grey, Information Collection Clearance Officer, Fish and Wildlife Service, MS 222–ARLSQ, 4401 North Fairfax Drive, Arlington, VA 22203 (mail); (703) 358–2269 (fax); or hope_grey@fws.gov (e-mail).

**FOR FURTHER INFORMATION CONTACT:** To request additional information about this IC, contact Hope Grey by mail, fax, or e-mail (see **ADDRESSES**) or by telephone at (703) 358–2482.

**SUPPLEMENTARY INFORMATION:**

*OMB Control Number:* 1018–0022.

*Title:* Federal Fish and Wildlife Permit Applications and Reports—Migratory Birds and Eagles, 50 CFR 10, 13, 21, and 22.

*Service Form Number(s):* 3–200–6 through 3–200–18, 3–200–67, 3–200–68, 3–200–77, 3–200–78, 3–200–79, 3–202–1 through 3–202–14, 3–186, and 3–186A.

*Type of Request:* Revision of currently approved collection.

*Affected Public:* Individuals; zoological parks; museums; universities; scientists; taxidermists; businesses; and Federal, State, tribal, and local governments.

*Respondent's Obligation:* Required to obtain or retain a benefit.

*Frequency of Collection:* On occasion for applications; annually or on occasion for reports.

*Estimated Annual Number of Respondents:* 29,844.

*Estimated Total Annual Responses:* 55,674.

*Estimated Time per Response:* Varies from 15 minutes to 12 hours depending on activity.

*Estimated Total Annual Burden Hours:* 47,331.

*Estimated Nonhour Cost Burden:* $706,300 for fees associated with permit applications.

*Abstract:* Our Regional Migratory Bird Permit Offices use information that we collect on permit applications to determine the eligibility of applicants for permits requested in accordance with the criteria in various Federal wildlife conservation laws and international treaties, including:

(1) Migratory Bird Treaty Act (16 U.S.C. 703 et seq.).

(2) Bald and Golden Eagle Protection Act (16 U.S.C. 668).

Service regulations implementing these statutes and treaties are in Chapter I, Subchapter B of Title 50 Code of Federal Regulations (CFR). These regulations stipulate general and specific requirements that, when met, allow us to issue permits to authorize activities that are otherwise prohibited.

This revised IC includes migratory bird and eagle permit applications and the reports associated with the permits. We have:

(1) Modified the format and content of the currently approved application forms so that they (a) are easier to understand and complete and (b) accommodate future electronic permitting.

(2) Added six new forms:

(a) FWS Form 3–200–15b (Eagle Parts for Native American Religious Purposes - Reorder Request) will enable Native Americans to send reorders directly to the National Eagle Repository, which distributes the parts, instead of to the Regional permit office.

(b) FWS Form 3–200–77 (Native American Religious Use - Eagle Take), FWS Form 3–200–78 (Native American Religious Use - Live Eagles), and FWS Form 3–200–79 (Special Purpose-Abatement Activities Using Raptors) will provide the public with applications specifically designed to address information necessary to issue permits for these activities.

(c) FWS Form 3–202–13 (Eagle Exhibition Annual Report) will facilitate reporting under Eagle Exhibition permits by clarifying that we need information about eagles only. Currently, permittees use FWS Form 3–202–5 (Special Purpose Possession Live/Dead (Education) Annual Report), which requests information on other migratory birds.

(d) FWS Form 3–202–14 (Native American Religious Use – Live Eagles Annual Report) will facilitate reporting under the permits for Native American religious use.

We have transferred FWS Forms 3–200–69 (CITES Import/Export – Eagle Transport for Scientific or Exhibition Purposes) and 3–200–70 (CITES Import/Export – Eagle Transportation for Indian Religious Purposes), currently approved under this information collection, to OMB Control Number 1018–0093.

*Comments:* On March 23, 2007, we published in the **Federal Register** (72 FR 13815) a notice of our intent to request that OMB renew this information collection. In that notice, we solicited comments for 60 days, ending on May 22, 2007. We received one comment. The comment did not address issues surrounding the proposed collection of information or the cost and hour burden estimates, but instead objected to other aspects of our program, such as killing of eagles. We have not made any changes to this collection as a result of the comment.

**III. Request for Comments**

We again invite comments concerning this IC on:

(1) whether or not the collection of information is necessary, including whether or not the information will have practical utility;

(2) the accuracy of our estimate of the burden for this collection of information;

(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.

Comments that you submit in response to this notice are a matter of public record. Before including your address, phone number, e-mail address, or other personal identifying information in your comment, you should be aware that your entire comment, including your personal identifying information, may be made publicly available at any time. While you can ask OMB in your comment to withhold your personal identifying information from public review, we cannot guarantee that it will be done.

Dated: June 29, 2007.

**Hope Grey,**

*Information Collection Clearance Officer, Fish and Wildlife Service.*

FR Doc. E7–14057 Filed 7–19–07; 08:45am≤

**Billing Code 4310–55–S**

## DEPARTMENT OF THE INTERIOR

## Fish and Wildlife Service

## Receipt of Applications for Permit

**AGENCY:** Fish and Wildlife Service, Interior.

**ACTION:** Notice of receipt of applications for permit.

**SUMMARY:** The public is invited to comment on the following applications to conduct certain activities with endangered species and/or marine mammals.

**DATES:** Written data, comments or requests must be received by August 20, 2007.

**ADDRESSES:** Documents and other information submitted with these applications are available for review, subject to the requirements of the Privacy Act and Freedom of Information Act, by any party who submits a written request for a copy of such documents within 30 days of the date of publication of this notice to: U.S. Fish and Wildlife Service, Division of Management Authority, 4401 North Fairfax Drive, Room 700, Arlington, Virginia 22203; fax 703/358–2281.

**FOR FURTHER INFORMATION CONTACT:** Division of Management Authority, telephone 703/358–2104.

**SUPPLEMENTARY INFORMATION:**

### Endangered Species

The public is invited to comment on the following applications for a permit to conduct certain activities with endangered species. This notice is provided pursuant to Section 10(c) of the Endangered Species Act of 1973, as amended (16 U.S.C. 1531 *et seq.*). Written data, comments, or requests for copies of these complete applications should be submitted to the Director (address above).

*Applicant:* Wildlife Conservation Society, Bronx Zoo, Bronx, NY, PRT–158751.

The applicant requests a permit to export one captive born Malayan tapir (*Tapirus indicus*) to the Toronto Zoo, Toronto, Canada for the purpose of enhancement of the survival of the species.

*Applicant:* Naples Zoo, Naples, FL, PRT–156539.

The applicant requests a permit to import four captive born ocelots (*Leopardus pardalis mitis*) from the Sbcampo, Bauru, and Casib Zoos, Brazil for the purpose of enhancement of the survival of the species.

*Applicant:* University of Massachusetts, Amherst, MA, PRT–158368.

The applicant requests a permit to import biological samples collected from wild mouse lemurs (*Microcebus griseorufus* syn. *Microcebus murinus*) in Madagascar for scientific research. This notification covers activities to be conducted by the applicant over a five-year period.

*Applicant:* Robert P. Remillard, Croydon, NH, PRT–158683.

The applicant requests a permit to import the sport-hunted trophy of one male bontebok (*Damaliscus pygargus pygargus*) culled from a captive herd maintained under the management program of the Republic of South Africa, for the purpose of enhancement of the survival of the species.

*Applicant:* Steve C. Dannecker, Grosse Pointe Woods, MI, PRT–158104.

The applicant requests a permit to import the sport-hunted trophy of one male bontebok (*Damaliscus pygargus pygargus*) culled from a captive herd maintained under the management program of the Republic of South Africa, for the purpose of enhancement of the survival of the species.

*Applicant:* Gregory B. Hagar, Iverness, FL, PRT–159501.

The applicant requests a permit to import the sport-hunted trophy of one male bontebok (*Damaliscus pygargus pygargus*) culled from a captive herd maintained under the management program of the Republic of South Africa, for the purpose of enhancement of the survival of the species.

*Applicant:* Marc L. Abel, Tulsa, OK, PRT–157455.

The applicant requests a permit to import the sport-hunted trophy of one male bontebok (*Damaliscus pygargus pygargus*) culled from a captive herd maintained under the management program of the Republic of South Africa, for the purpose of enhancement of the survival of the species.

**Endangered Marine Mammals and Marine Mammals**

The public is invited to comment on the following applications for a permit to conduct certain activities with endangered marine mammals and/or marine mammals. The applications were submitted to satisfy requirements of the Endangered Species Act of 1973, as amended (16 U.S.C. 1531 *et seq.*) and/or the Marine Mammal Protection Act of 1972, as amended (16 U.S.C. 1361 *et seq.*), and the regulations governing endangered species (50 CFR Part 17) and/or marine mammals (50 CFR Part 18). Written data, comments, or requests for copies of the complete applications or requests for a public hearing on these applications should be submitted to the Director (address above). Anyone requesting a hearing should give specific reasons why a hearing would be appropriate. The holding of such a hearing is at the discretion of the Director.

*Applicant:* Jennifer Miksis-Olds, Pennsylvania State University, State College, PA, PRT–071799.

The applicant requests renewal and amendment of a permit to take wild manatees (*Trichechus manatus*) in Florida using sonar for the purpose of scientific research. This notification covers activities to be conducted by the applicant over a five-year period.

Concurrent with the publication of this notice in the **Federal Register**, the Division of Management Authority is forwarding copies of the above applications to the Marine Mammal Commission and the Committee of Scientific Advisors for their review.

*Applicant:* Thomas M. Sharko, Milford, NJ, PRT–157656.

The applicant requests a permit to import a polar bear (*Ursus maritimus*) sport hunted from the Lancaster Sound polar bear population in Canada for personal, noncommercial use.

*Applicant:* Elizabeth Harris, Russellville, AR, PRT–155649.

The applicant requests a permit to import a polar bear (*Ursus maritimus*) sport hunted from the Lancaster Sound polar bear population in Canada for personal, noncommercial use.

*Applicant:* Philip E. Carlin, Columbus, OH, PRT–157475.

The applicant requests a permit to import a polar bear (*Ursus maritimus*) sport hunted from the Northern Beaufort Sea polar bear population in Canada for personal, noncommercial use.

*Applicant:* Christopher Ring, Brackettville, TX, PRT–156520.

The applicant requests a permit to import a polar bear (*Ursus maritimus*) sport hunted from the Lancaster Sound polar bear population in Canada for personal, noncommercial use.

*Applicant:* Michael J. Riley, Frankfort, KY, PRT–156536.

The applicant requests a permit to import a polar bear (*Ursus maritimus*) sport hunted from the Lancaster Sound polar bear population in Canada for personal, noncommercial use.

Dated: July 6, 2007.

**Amneris Siaca,**

*Acting Senior Permit Biologist, Branch of Permits, Division of Management Authority.*

[FR Doc. E7–14059 Filed 7–19–07; 8:45 am]

BILLING CODE 4310–55–P

---

## DEPARTMENT OF THE INTERIOR

### Fish and Wildlife Service

### Receipt of Applications for Permit

**AGENCY:** Fish and Wildlife Service, Interior.

**ACTION:** Notice of receipt of applications for permit.

---

**SUMMARY:** The public is invited to comment on the following applications to conduct certain activities with endangered species and/or marine mammals.

**DATES:** Written data, comments or requests must be received by August 20, 2007.

**ADDRESSES:** Documents and other information submitted with these applications are available for review, subject to the requirements of the Privacy Act and Freedom of Information Act, by any party who submits a written request for a copy of such documents within 30 days of the date of publication of this notice to: U.S. Fish and Wildlife Service, Division of Management Authority, 4401 North Fairfax Drive, Room 700, Arlington, Virginia 22203; fax 703/358–2281.

**FOR FURTHER INFORMATION CONTACT:** Division of Management Authority, telephone 703/358–2104.

**SUPPLEMENTARY INFORMATION:**

**Endangered Species**

The public is invited to comment on the following applications for a permit to conduct certain activities with endangered species. This notice is provided pursuant to Section 10(c) of the Endangered Species Act of 1973, as amended (16 U.S.C. 1531 *et seq.*). Written data, comments, or requests for copies of these complete applications should be submitted to the Director (address above).

*Applicant:* NOAA Fisheries/Pacific Islands Regional Office, Honolulu, HI, PRT–022729.

The applicant requests re-issuance of their permit to introduce from the high seas samples and/or whole carcasses of green sea turtle (*Chelonia mydas*), leatherback sea turtle (*Dermochelys coriacea*), hawksbill sea turtle (*Eretmochelys imbricata*), olive ridley sea turtle (*Lepidochelys olivacea*), Kemp's ridley sea turtle (*Lepidochelys kempii*) and short-tailed albatross (*Diomedea albatrus*) for the purpose of enhancement of the species through scientific research. The applicant has requested to amend their permit to reflect the program's new name and location. This notice covers activities conducted by the applicant over a five-year period.

*Applicant:* Zoological Society of San Diego, San Diego, CA, PRT–152101.

The applicant requests a permit to import one male and one female captive-born dhole (*Cuon alpinus*) from the Yokohama Zoological Gardens Zoorasia, Yokohama, Japan, for the purpose of enhancement of the species through captive propagation.

*Applicant:* Hugh C. Kelley, Beaumont, TX, PRT–155653.

The applicant requests a permit to import the sport-hunted trophy of one male bontebok (*Damaliscus pygargus pygargus*) culled from a captive herd maintained under the management program of the Republic of South Africa, for the purpose of enhancement of the survival of the species.

*Applicant:* David J. Lechel, Albuquerque, NM, PRT–155498.

The applicant requests a permit to import the sport-hunted trophy of one male bontebok (*Damaliscus pygargus pygargus*) culled from a captive herd maintained under the management program of the Republic of South Africa, for the purpose of enhancement of the survival of the species.

*Applicant:* Carl W. McKee, Irving, TX, PRT–152980.

The applicant requests a permit to import the sport-hunted trophy of one male bontebok (*Damaliscus pygargus pygargus*) culled from a captive herd maintained under the management program of the Republic of South Africa, for the purpose of enhancement of the survival of the species.

*Applicant:* Douglas E. Hutt, Dallas, TX, PRT–149113.

The applicant requests a permit to import the sport-hunted trophy of one male bontebok (*Damaliscus pygargus pygargus*) culled from a captive herd maintained under the management program of the Republic of South Africa, for the purpose of enhancement of the survival of the species.

*Applicant:* John S. MacDonnell, Arcadia, CA, PRT–151123.

The applicant requests a permit to import the sport-hunted trophy of one male bontebok (*Damaliscus pygargus pygargus*) culled from a captive herd maintained under the management program of the Republic of South Africa, for the purpose of enhancement of the survival of the species.

*Applicant:* Gatti Productions, Inc., Orange, CA, PRT–055424, 055425, 055426 and 673539.

The applicant requests the re-issuance of permits for the re-export and re-import of four wild born Asian elephants (*Elephas maximus*) to and from worldwide locations for the purpose of enhancement of the species through conservation education. The permit numbers and animals are [055424, Tiki; 055425, Queen; 055426, Debbie; 673539, Wanda]. This notification covers activities to be conducted by the applicant over a three-year period and the import of any potential progeny born while overseas.

**Marine Mammals**

The public is invited to comment on the following application for a permit to conduct certain activities with marine mammals. The application was submitted to satisfy requirements of the Marine Mammal Protection Act of 1972, as amended (16 U.S.C. 1361 *et seq.*), and the regulations governing marine mammals (50 CFR Part 18). Written data, comments, or requests for copies of the complete applications or requests for a public hearing on these applications should be submitted to the Director (address above). Anyone requesting a hearing should give specific reasons why a hearing would be appropriate. The holding of such a hearing is at the discretion of the Director.

*Applicant:* David L. Duncan, Oklahoma City, OK, PRT–156814.

The applicant requests a permit to import a polar bear (*Ursus maritimus*) sport hunted from the Northern Beaufort Sea polar bear population in Canada for personal, noncommercial use.

Dated: June 29, 2007.

**Michael S. Moore,**

*Senior Permit Biologist, Branch of Permits, Division of Management Authority.*

[FR Doc. E7–14081 Filed 7–19–07; 8:45 am]

BILLING CODE 4310–55–P

## DEPARTMENT OF THE INTERIOR

## Fish and Wildlife Service

## Issuance of Permits

**AGENCY:** Fish and Wildlife Service, Interior.

**ACTION:** Notice of issuance of permits for endangered species and/or marine mammals.

**SUMMARY:** The following permits were issued.

**ADDRESSES:** Documents and other information submitted with these applications are available for review, subject to the requirements of the Privacy Act and Freedom of Information Act, by any party who submits a written request for a copy of such documents to: U.S. Fish and Wildlife Service, Division of Management Authority, 4401 North Fairfax Drive, Room 700, Arlington, Virginia 22203; fax 703/358–2281.

**FOR FURTHER INFORMATION CONTACT:** Division of Management Authority, telephone 703/358–2104.

**SUPPLEMENTARY INFORMATION:** Notice is hereby given that on the dates below, as authorized by the provisions of the Endangered Species Act of 1973, as amended (16 U.S.C. 1531 *et seq.*), and/or the Marine Mammal Protection Act of 1972, as amended (16 U.S.C. 1361 *et seq.*), the Fish and Wildlife Service issued the requested permits subject to certain conditions set forth therein. For each permit for an endangered species, the Service found that (1) the application was filed in good faith, (2) the granted permit would not operate to the disadvantage of the endangered species, and (3) the granted permit would be consistent with the purposes and policy set forth in Section 2 of the Endangered Species Act of 1973, as amended.

ENDANGERED SPECIES

| Permit number | Applicant | Receipt of application **Federal Register** notice | Permit issuance date |
|---|---|---|---|
| 146529 | Mary K. Gonder, University of Maryland, Dept. of Biology. | 72 FR 11375; March 13, 2007 | June 20, 2007. |

ENDANGERED MARINE MAMMALS AND MARINE MAMMALS

| Permit number | Applicant | Receipt of application **Federal Register** notice | Permit issuance date |
|---|---|---|---|
| 038448 | Iskande L.V. Larkin, University of Florida | 71 FR 31198; June 1, 2006 | June 29, 2007. |
| 054026 | Hubbs-Sea World Research Institute | 71 FR 16823; April 4, 2006 | June 29, 2007. |
| 107933 | Wildlife Trust, Inc. | 70 FR 58234; October 5, 2005 | June 29, 2007. |

Dated: June 29, 2007.

**Michael S. Moore,**

*Senior Permit Biologist, Branch of Permits, Division of Management Authority.*

[FR Doc. E7–14083 Filed 7–19–07; 8:45 am]

**BILLING CODE 4310–55–P**

---

## DEPARTMENT OF THE INTERIOR

### Bureau of Land Management

**[UT–910–07–1150–PH–24–1A]**

### Notice of Utah Resource Advisory Council Meeting

**AGENCY:** Bureau of Land Management, Department of Interior.

**ACTION:** Notice of Utah Resource Advisory Council (RAC) Meeting.

**SUMMARY:** In accordance with the Federal Land Policy and Management Act (FLPMA) and The Federal Advisory Committee Act of 1972 (FACA), the U.S. Department of the Interior, Bureau of Land Management's (BLM) Utah Resource Advisory Council (RAC) will meet as indicated below.

**DATES:** The Utah Resource Advisory Council (RAC) will meet September 14, 2007.

**ADDRESSES:** The RAC will meet at the Holiday Inn, San Rafael Conference Room, 838 Westwood Blvd., Price, Utah.

**FOR FURTHER INFORMATION:** Contact Sherry Foot, Special Programs Coordinator, Utah State Office, Bureau of Land Management, P.O. Box 45155, Salt Lake City, Utah, 84145–0155; phone (801) 539–4195.

**SUPPLEMENTARY INFORMATION:** On September 14, from 9 a.m. to 5 p.m., the RAC will be given recreation fee presentations from the BLM's Monticello Field Office and the Cleveland Lloyd Dinosaur Quarry. The U.S. Forest Service will present fee presentations for Mirror Lake, American Fork Canyon, and Flaming Gorge. BLM will provide an overview of its oil and gas leasing process. A public comment period, where members of the public may address the RAC, is scheduled from 4:15 p.m. to 4:45 p.m. Written comments may be sent to the Bureau of Land Management address listed above. All meetings are open to the public; however, transportation, lodging, and meals are the responsibility of the participating public.

Dated: July 12, 2007.

**Selma Sierra,**

*State Director.*

[FR Doc. E7–14054 Filed 7–19–07; 8:45 am]

**BILLING CODE 4310–$$;–P**

---

## DEPARTMENT OF THE INTERIOR

### Minerals Management Service

### Notice of Availability of the Record of Decision for Outer Continental Shelf (OCS), Western Gulf of Mexico (GOM), Oil and Gas Lease Sale 204

**AGENCY:** Minerals Management Service, Interior.

**ACTION:** Notice of availability of the Record of Decision.

**SUMMARY:** The Minerals Management Service (MMS) has issued a Record of Decision for OCS Western GOM Lease Sale 204 (August 2007). As part of the decision process, MMS published in April 2007 a final environmental impact statement (EIS) on the 2007–2012 Western and Central GOM oil and gas leasing proposals, including Sale 204. In preparing this decision, MMS has considered alternatives to the proposed actions, the impacts of Sale 204 as presented in the EIS, and all comments received throughout the EIS-process.

*Availability:* To obtain a copy of the Record of Decision and Final EIS, you may contact the Minerals Management Service, Gulf of Mexico OCS Region, Public Information Office (MS 5034), 1201 Elmwood Park Boulevard, Room 114, New Orleans, Louisiana 70123–2394 (1–800–200–GULF). An electronic copy of the Record of Decision and Final EIS are available at the MMS's Internet Web site at: *http://www.gomr.mms.gov/homepg/regulate/environ/nepa/nepaprocess.html.*

**FOR FURTHER INFORMATION CONTACT:** Mr. Dennis Chew, Minerals Management Service, Gulf of Mexico OCS Region, 1201 Elmwood Park Boulevard, New Orleans, Louisiana 70123–2394, (504) 736–2793.

Dated: July 11, 2007.

**Chris C. Oynes,**

*Associate Director for Offshore Minerals Management.*

[FR Doc. E7–14078 Filed 7–19–07; 8:45 am]

**BILLING CODE 4310–MR–P**

---

## DEPARTMENT OF THE INTERIOR

### Minerals Management Service

### Outer Continental Shelf (OCS) Western Gulf of Mexico (GOM) Oil and Gas Lease Sale 204

**AGENCY:** Minerals Management Service.

**ACTION:** Final Notice of Sale (FNOS) 204.

**SUMMARY:** On August 22, the MMS will open and publicly announce bids received for blocks offered in Western GOM Oil and Gas Lease Sale 204, pursuant to the OCS Lands Act (43 U.S.C. 1331–1356, as amended) and the regulations issued thereunder (30 CFR Part 256). The Final Notice of Sale 204 Package (FNOS 204 Package) contains information essential to bidders, and bidders are charged with the knowledge of the documents contained in the Package.

**DATES:** Public bid reading will begin at 9 a.m., Wednesday, August 22, 2007, in the Grand Salon Suite B at the Hilton New Orleans Riverside Hotel, Two Poydras Street, New Orleans, Louisiana. All times referred to in this document are local New Orleans times, unless otherwise specified.

**ADDRESSES:** Bidders can obtain a FNOS 204 Package containing this Notice of Sale and several supporting and essential documents referenced herein from the MMS Gulf of Mexico Region Public Information Unit, 1201 Elmwood Park Boulevard, New Orleans, Louisiana 70123–2394, (504) 736–2519 or (800) 200–GULF, or via the MMS Internet Web site at *http://www.gomr.mms.gov.*

*Filing of Bids:* Bidders must submit sealed bids to the Regional Director (RD), MMS Gulf of Mexico Region, 1201 Elmwood Park Boulevard, New Orleans Louisiana 70123–2394, between 8 a.m. and 4 p.m. on normal working days, and from 8 a.m. to the Bid Submission Deadline of 10 a.m. on Tuesday, August 21, 2007. If bids are mailed, please address the envelope containing all of the sealed bids as follows:

*Attention:* Supervisor, Sales and Support Unit (MS 5422), Leasing Activities Section, MMS Gulf of Mexico Region, 1201 Elmwood Park Boulevard, New Orleans, Louisiana 70123–2394. Contains Sealed Bids for Oil and Gas Lease Sale 204. Please Deliver to Ms. Nancy Kornrumpf, 6th Floor, Immediately.

**Please Note:** Bidders mailing their bid(s) are advised to call Ms. Nancy Kornrumpf (504) 736–2726, immediately after putting their bid(s) in the mail. If the RD receives bids later than the time and date specified above, he will return those bids unopened to bidders. Bidders may not modify or withdraw their bids unless the RD receives a written modification or written withdrawal request prior to 10 a.m. on Tuesday, August 21, 2007. Should an unexpected event such as flooding or travel restrictions be significantly disruptive to bid submission, the MMS Gulf of Mexico Region may extend the Bid Submission Deadline. Bidders may call (504) 736–0557 for information about the possible extension of the Bid Submission Deadline due to such an event.

*Areas Offered For Leasing:* The MMS is offering for leasing all blocks and partial blocks listed in the document "Blocks Available for Leasing in

Western GOM Oil and Gas Lease Sale 204'' included in the FNOS 204 Package. All of these blocks are shown on the following Leasing Maps and Official Protraction Diagrams:

**Outer Continental Shelf Leasing Maps—Texas Map Numbers 1 Through 8 (These 16 Maps Sell for $2.00 Each.)**

TX1 South Padre Island Area (revised November 1, 2000).
TX1A South Padre Island Area, East Addition (revised November 1, 2000).
TX2 North Padre Island Area (revised November 1, 2000).
TX2A North Padre Island Area, East Addition (revised November 1, 2000).
TX3 Mustang Island Area (revised November 1, 2000).
TX3A Mustang Island Area, East Addition (revised September 3, 2002).
TX4 Matagorda Island Area (revised November 1, 2000).
TX5 Brazos Area (revised November 1, 2000).
TX5B Brazos Area, South Addition (revised November 1, 2000).
TX6 Galveston Area (revised November 1, 2000).
TX6A Galveston Area, South Addition (revised November 1, 2000).
TX7 High Island Area (revised November 1, 2000).
TX7A High Island Area, East Addition (revised November 1, 2000).
TX7B High Island Area, South Addition (revised November 1, 2000).
TX7C High Island Area, East Addition, South Extension (revised November 1, 2000).
TX8 Sabine Pass Area (revised November 1, 2000).

**Outer Continental Shelf Leasing Maps—Louisiana Map Numbers 1A, 1B, and 12 (These 3 Maps Sell for $2.00 Each.)**

LA1A West Cameron Area, West Addition (revised February 28, 2007).
LA1B West Cameron Area, South Addition (revised February 28, 2007).
LA12 Sabine Pass Area (revised February 28, 2007).

**Outer Continental Shelf Official Protraction Diagrams (These 7 Diagrams Sell for $2.00 Each.)**

NG14–03 Corpus Christi (revised November 1, 2000).
NG14–06 Port Isabel (revised November 1, 2000).
NG15–01 East Breaks (revised November 1, 2000).
NG15–02 Garden Banks (revised February 28, 2007).
NG15–04 Alaminos Canyon (revised November 1, 2000).
NG15–05 Keathley Canyon (revised February 28, 2007).
NG15–08 Sigsbee Escarpment (revised February 28, 2007).

**Please Note:** A CD–ROM (in ARC/INFO and Acrobat (.pdf) format) containing all of the GOM Leasing Maps and Official Protraction Diagrams, except for those not yet converted to digital format, is available from the MMS Gulf of Mexico Region Public Information Unit for a price of $15. These GOM Leasing Maps and Official Protraction Diagrams are also available for free online in .pdf and .gra format at *http://www.gomr.mms.gov/homepg/lsesale/map_arc.html.*

For the current status of all Western GOM Leasing Maps and Official Protraction Diagrams, please refer to 66 FR 28002 (published May 21, 2001), 67 FR 60701 (published September 26, 2002), and 72 FR 27590 (published May 16, 2007). In addition, Supplemental Official OCS Block Diagrams (SOBDs) for these blocks are available for blocks which contain the ''U.S. 200 Nautical Mile Limit'' line and the ''U.S.-Mexico Maritime Boundary'' line. These SOBDs are also available from the MMS Gulf of Mexico Region Public Information Unit. For additional information, please call Ms. Tara Montgomery (504) 736–5722.

All blocks are shown on these Leasing Maps and Official Protraction Diagrams. The available Federal acreage of all whole and partial blocks in this lease sale is shown in the document ''List of Blocks Available for Leasing in Lease Sale 204'' included in the FNOS 204 Package. Some of these blocks may be partially leased or deferred, or transected by administrative lines such as the Federal/State jurisdictional line. A bid on a block must include all of the available Federal acreage of that block. Also, information on the unleased portions of such blocks is found in the document ''Western Gulf of Mexico Lease Sale 204—Unleased Split Blocks and Available Unleased Acreage of Blocks with Aliquots and Irregular Portions Under Lease or Deferred'' included in the FNOS 204 Package.

*Areas Not Available For Leasing:* The following whole and partial blocks are not offered for lease in this sale:

Block currently under appeal (although currently unleased, the following block is under appeal and bids will not be accepted:

*High Island (Area TX7)*

Block 21.

Whole blocks and portions of blocks which lie within the boundaries of the Flower Garden Banks National Marine Sanctuary at the East and West Flower Garden Banks and Stetson Bank (the following list includes all blocks affected by the Sanctuary boundaries):

*High Island, East Addition, South Extension (Area TX7C)*

*Whole Blocks:* A–375, A–398.

*Portions of Blocks:* A–366, A–367, A–374, A–383, A–384, A–385, A–388, A–389, A–397, A–399, A–401.

*High Island, South Addition (Area TX7B)*

*Portions of Blocks:* A–502, A–513.

*Garden Banks (Area NG15–02)*

*Portions of Blocks:* 134, 135.

Whole blocks and portions which lie within the former Western Gap portion of the 1.4 nautical mile buffer zone north of the continental shelf boundary between the *United States and Mexico:*

*Keathley Canyon (Map Number NG15–05)*

*Portions of Blocks:* 978 through 980.

*Sigsbee Escarpment (Map Number NG15–08)*

*Whole Blocks:* 11, 57, 103, 148, 149, 194.

*Portions of Blocks:* 12 through 14, 58 through 60, 104 through 106, 150.

*Statutes and Regulations:* Each lease issued in this lease sale is subject to the OCS Lands Act of August 7, 1953; 43 U.S.C. 1331 *et seq.*, as amended, hereinafter called ''the Act''; all regulations issued pursuant to the Act and in existence upon the Effective Date of the lease; all regulations issued pursuant to the statute in the future which provide for the prevention of waste and conservation of the natural resources of the OCS and the protection of correlative rights therein; and all other applicable statutes and regulations.

*Lease Terms and Conditions:* Initial periods, extensions of initial periods, minimum bonus bid amounts, rental rates, escalating rental rates for leases with an approved extension of the initial 5-year period, royalty rates, minimum royalty, and royalty suspension areas, if any, applicable to this sale are noted below. Depictions of related areas are shown on the map ''Lease Terms and Economic Conditions, Lease Sale 204, Final'' for leases resulting from this lease sale.

**Please Note:** The MMS published new official leasing maps and protraction diagrams that include the newly-defined administrative planning area boundaries implemented in this sale. These new boundaries are depicted on the ''Lease Terms and Economic Conditions, Lease Sale 204, Final'' map.

*Initial Periods:* 5 years for blocks in water depths of less than 400 meters; 8 years for blocks in water depths of 400 to less than 800 meters (pursuant to 30 CFR 256.37, commencement of an exploratory well is required within the first 5 years of the initial 8 year term to avoid lease cancellation); and 10 years for blocks in water depths of 800 meters or deeper.

*Extensions of Initial Periods:* A 5-year initial term for a lease issued from this sale may be extended to 8 years if a well targeting hydrocarbons below 25,000 feet true vertical depth subsea (TVD SS) is spudded within the initial 5-year term. The 3-year extension may be granted in cases where the well is drilled to a target below 25,000 TVD SS and also in cases where the well does not reach a depth below 25,000 TVD SS due to mechanical or safety reasons.

In order for the lease term to be extended to 8 years, you are required to submit to the Regional Supervisor for Production and Development within 30 days after completion of the drilling operation a letter providing the well number, spud date, information demonstrating the target below 25,000 feet TVD SS, and if applicable, any operational reasons such as safety or mechanical problems encountered that prevented the well from reaching a depth below 25,000 TVD SS. The Regional Supervisor must concur in writing that the conditions have been met to extend the lease term 3 years. The Regional Supervisor will provide written confirmation of any lease extension within 30 days of receipt of the letter provided.

For any lease that has a well spudded in the first 5 years of the initial period with a hydrocarbon target below 25,000 feet TVD SS, the regulations found at 30 CFR 250.175(a), (b), and (c) will not be applicable at the end of the 5th year. For any lease that does not have a well spudded in the first 5 years of the initial period which targets hydrocarbons below 25,000 feet TVD SS, the regulations found at 30 CFR 250.175(a), (b), and (c) will be applicable, but the 3-year extension will not be available. At the end of the 8th year, the lessee is free to use all lease term extension provisions under the regulations.

*Minimum Bonus Bid Amounts:* A bonus bid will not be considered for acceptance unless it provides for a cash bonus in the amount of $25 or more per acre or fraction thereof for blocks in water depths of less than 400 meters or $37.50 or more per acre or fraction thereof for blocks in water depths of 400 meters or deeper; to confirm the exact calculation of the minimum bonus bid amount for each block, see ‘‘List of Blocks Available for Leasing’’ which will be contained in the FNOS 204 Package. Please note that bonus bids must be in whole dollar amounts (i.e., any cents will be disregarded by the MMS).

*Rental Rates:* $6.25 per acre or fraction thereof for blocks in water depths of less than 200 meters and $9.50 per acre or fraction thereof for blocks in water depths of 200 meters or deeper, to be paid on or before the 1st day of each lease year until a discovery in paying quantities of oil or gas, then at the expiration of each lease year until the start of royalty-bearing production. An exception to this rental rate requirement will be escalating rental rates in the 6th, 7th, and 8th year for leases with an approved extension of the initial 5 year period, as noted in the following paragraph of this document.

*Escalating Rental Rates for leases with an approved extension of the initial 5 year period:* Any lease granted a 3-year extension beyond the initial 5-year period will pay an escalating rental rate as set out in the following table, to be paid on or before the 1st day of each lease year until determination of well producibility is received, then at the expiration of each lease year until the start of royalty-bearing production:

| Extended lease year number | Escalating annual rental rate* for a lease in: less than 200 meters water depth | Escalating annual rental rate* for a lease in: 200 to less than 400 meters water depth |
|---|---|---|
| 6 | $12.50 per acre or fraction thereof | $19.00 per acre or fraction thereof. |
| 7 | $18.75 per acre or fraction thereof | $28.50 per acre or fraction thereof. |
| 8 | $25.00 per acre or fraction thereof | $38.00 per acre or fraction thereof. |

* If another well is spudded during the 3-year extended term of the lease and targets hydrocarbons below 25,000 feet TVD SS, and MMS concurs that this situation has been met, the rental rate will be frozen at the rental rate in effect during the lease year in which this well was spudded.

*Royalty Rates:* 16⅔ percent royalty rate for blocks in all water depths, except during periods of royalty suspension, to be paid monthly on the last day of the month next following the month during which the production is obtained.

*Minimum Royalty:* After the start of royalty-bearing production and not withstanding any royalty suspension that may apply: $6.25 per acre or fraction thereof per year for blocks in water depths of less than 200 meters and $9.50 per acre or fraction thereof per year for blocks in water depths of 200 meters or deeper, to be paid at the expiration of each lease year with credit applied for actual royalty paid during the lease year. If actual royalty paid exceeds the minimum royalty requirement, then no minimum royalty payment is due.

**Royalty Suspension Provisions**

*Leases with royalty suspension volumes (RSV), are authorized under existing MMS rules at 30 CFR part 260. There are no circumstances under which a single lease could receive a royalty suspension both for deep gas production and for deepwater production.* Section 344 of the Energy Policy Act of 2005 (EPAct05) extends existing deep gas incentives in two ways. First, it mandates a RSV of at least 35 billion cubic feet (Bcf) of natural gas for certain wells completed in a third drilling depth category (greater than 20,000 feet subsea) for leases in 0–400 meters of water. Second, section 344 directed that the same incentives prescribed in MMS' 2004 rule for wells completed between 15,000 feet and 20,000 feet TVD SS on leases in 0–200 meters of water be applied to leases in 200–400 meters of water. Section 345 of the EPAct05 directed continuation of the MMS deepwater incentive program utilized since 2001 in the Gulf of Mexico for leases issued between August 8, 2005, and August 8, 2010, and provides for an increase in royalty suspension volume from the MMS rule-specified 12 MMBOE to 16 MMBOE for leases in water depths greater than 2000 meters.

**Deep Gas Royalty Suspensions**

A lease issued as a result of this sale may be eligible for royalty relief authorized under the EPAct05, Section 344 (Incentives for Natural Gas Production from Deep Wells in the Shallow Waters of the Gulf of Mexico). The MMS published a proposed rule on May 18, 2007, and will publish a final rule implementing this section of the EPAct05. If this lease is eligible, it will be subject to the provisions of that final rulemaking, including any price threshold provisions. Please refer to the Royalty Suspension Provisions cited below.

A. *The following Royalty Suspension Provisions apply to qualifying deep wells on leases at least partly in water depths up to 200 meters:* Such wells require a perforated interval the top of which is from 15,000 to less than 20,000 feet TVD SS. Suspension volumes, conditions, and requirements prescribed in 30 CFR 203.41 through 203.47 and any amendments or successor regulations apply to deep gas production from a lease in this water depth range issued as a result of this sale. Definitions that apply to this category of royalty relief can be found in 30 CFR 203.0. To receive this category of royalty relief, production from a qualified well or drilling of a certified unsuccessful well must commence before May 3, 2009.

B. *Royalty Suspension Provisions will apply to qualifying deep wells on leases entirely in water depths more than 200 but less than 400 meters:* Such wells require a perforated interval the top of which is from 15,000 to less than 20,000 feet TVD SS. The EPAct05 requires the Secretary to issue regulations granting suspension volumes to leases entirely in water depth more than 200 but less than 400 meters that will be calculated using the same methodology as is currently employed for leases at least partly in water depth up to 200 meters. Deep wells on leases in the 200–400 meter water depth range issued in Sale 204 will be eligible for royalty relief prescribed in the final rulemaking implementing section 344 of the EPAct05.

C. *Royalty Suspension Provisions will apply to qualifying ultra deep wells on leases entirely in water depths less than 400 meters:* Ultra deep wells (i.e., wells completed with a perforated interval the top of which is 20,000 feet or deeper TVD SS) on leases entirely in water depths less than 400 meters issued in Sale 204 will be eligible for royalty relief prescribed in a final rulemaking implementing section 344 of the EPAct05.

**Deep Water Royalty Suspensions**

*The following Royalty Suspension Provisions apply to deep water Oil and Gas Production:* A lease issued as a result of this sale may be eligible for royalty relief under the EPAct05, section 345 (Royalty Relief for Deep Water Production). The following Royalty Suspension Provisions for deep water oil and gas production apply to a lease issued as a result of this sale. In addition to these provisions, and the EPAct05, refer to 30 CFR 218.151 and applicable parts of 260.120–260.124 for regulations on how royalty suspensions relate to field assignment, product types, rental obligations, and supplemental royalty relief.

1. A lease in water depths of 400 meters or more will receive a royalty suspension as follows, according to the water depth range in which the lease is located:

400 meters to less than 800 meters: 5 million barrels of oil equivalent (BOE) .

800 meters to less than 1600 meters: 9 million BOE.

1600 meters to 2000 meters: 12 million BOE.

Greater than 2000 meters: 16 million BOE.

2. The lessee must pay royalty on production that would otherwise receive royalty relief under 30 CFR Part 260 or supplemental relief under 30 CFR Part 203, and such production will count towards the royalty suspension volume, in any calendar year during which the arithmetic average of the daily closing prices for the nearby delivery month on the New York Mercantile Exchange (NYMEX) for the applicable product exceeds the adjusted product price threshold.

(a) The base level price threshold for light sweet crude oil is set at $35.75 per barrel in 2006. The adjusted oil price threshold in any subsequent calendar year is computed by changing the base price by the percentage by which the implicit price deflator for the gross domestic product has changed during the calendar year.

(b) The base level price threshold for natural gas is set at $4.47 per million British thermal units (MMBTU) in 2006. The adjusted gas price threshold in any subsequent calendar year is computed by changing the base price by the percentage by which the implicit price deflator for the gross domestic product has changed during the calendar year.

(c) As an example, if the deflator indicates that inflation is 2.5 percent in 2007, then the price threshold in calendar year 2007 would become $36.64 per barrel for oil and $4.58 for gas. Therefore, royalty on oil production in calendar year 2007 would be due if the average of the daily closing prices for the nearby delivery month on the NYMEX in 2007 exceeds $36.64 per barrel and royalty on gas production in calendar year 2007 would be due if the average of the daily closing prices for the nearby delivery month on the NYMEX in 2007 exceeds $4.58 per MMBTU.

(d) The MMS plans to provide notice in March when adjusted price thresholds for the preceding year were exceeded. Once this determination is made, based on the then-most recent implicit price deflator information, any subsequent adjustments in the implicit price deflator published by the U.S. Government will not affect the determination previously made for that year by MMS regarding lessee qualification for royalty relief. Information on price thresholds is available at the MMS Web site (*http://www.mms.gov/econ*).

(e) In cases where the actual average price for the product exceeds the adjusted price threshold in any calendar year, royalties must be paid no later than 90 days after the end of the year (see 30 CFR 260.122(b)(2) for more detail) and royalties must be paid provisionally in the following calendar year (See 30 CFR 260.122(c) for more detail).

(f) Full royalties are owed on all production from a lease after the Royalty Suspension Volume is exhausted, beginning on the first day of the month following the month in which the Royalty Suspension Volume is exhausted.

*Lease Stipulations*: The map ''Stipulations and Deferred Blocks, Lease Sale 204, Final'' lists those blocks on which one or more of five lease stipulations apply: (1) Topographic Features; (2) Military Areas; (3) Operations in the Naval Mine Warfare Area; (4) Law of the Sea Convention Royalty Payment; and (5) Protected Species.

**Please Note:** The MMS published new official leasing maps and protraction diagrams that include the newly-defined administrative planning area boundaries implemented in this sale. These new boundaries are depicted on the ''Stipulations and Deferred Blocks, Lease Sale 204, Final'' map.

The texts of the stipulations are contained in the document ''Lease Stipulations for Oil and Gas Lease Sale 204, Final'' included in the FNOS 204 Package. In addition, the ''List of Blocks Available for Leasing'' which will be contained in the FNOS 204 Package will identify for each block listed the lease stipulations applicable to that block.

*Information To Lessees*: The FNOS 204 Package contains an ''Information To Lessees'' document that provides detailed information on certain specific issues pertaining to this oil and gas lease sale.

*Method of Bidding*: For each block bid upon, a bidder must submit a separate signed bid in a sealed envelope labeled ''Sealed Bid for Oil and Gas Lease Sale 204, not to be opened until 9 a.m., Wednesday, August 22, 2007.'' The submitting company's name, its GOM Company number, the map name, map number, and block number should be clearly identified on the outside of the envelope. Please refer to the sample bid envelope included within the FNOS 204 Package. Please also refer to the Telephone Numbers/Addresses of Bidders Form included within the FNOS 204 Package. We are requesting that you provide this information in the format suggested for each lease sale. Please provide this information prior to or at the time of bid submission. Do not enclose this form inside the sealed bid envelope. The total amount of the bid must be in a whole dollar amount; any cent amount above the whole dollar will be ignored by the MMS. Details of the information required on the bid(s) and the bid envelope(s) are specified in the document ''Bid Form and Envelope'' contained in the FNOS 204 Package. A blank bid form has been provided for your convenience which may be copied and filled in.

The MMS published in the **Federal Register** a list of restricted joint bidders, which applies to this lease sale, at 72 FR 19214 on April 17, 2007. Please also refer to joint bidding provisions at 30 CFR 256.41 for additional information. Bidders must execute all documents in conformance with signatory authorizations on file in the MMS Gulf of Mexico Region Adjudication Unit. Partnerships also must submit or have on file a list of signatories authorized to bind the partnership. Bidders submitting joint bids must include on the bid form the proportionate interest of each participating bidder, stated as a percentage, using a maximum of five decimal places, e.g., 33.33333 percent. The MMS may require bidders to submit other documents in accordance with 30 CFR 256.46. The MMS warns bidders against violation of 18 U.S.C. 1860 prohibiting unlawful combination or intimidation of bidders. Bidders are advised that the MMS considers the signed bid to be a legally binding obligation on the part of the bidder(s) to comply with all applicable regulations, including payment of the one-fifth bonus bid amount on all high bids. A statement to this effect must be included on each bid (see the document ''Bid Form and Envelope'' contained in the FNOS 204 Package).

*Rounding*: The following procedure must be used to calculate the minimum bonus bid, annual rental, and minimum royalty: Round up to the next whole acreage amount if the tract acreage contains a decimal figure prior to calculating the minimum bonus bid, annual rental, and minimum royalty amounts. The appropriate rate per acre is applied to the whole non-decimal (rounded up) acreage figure, and the resultant calculation is rounded up to the next whole dollar amount if the calculation results in a decimal figure (see next paragraph).

**Please Note:** The minimum bonus bid calculation, including all rounding, is shown in the document ''List of Blocks Available for Leasing in Lease Sale 204'' included in the FNOS 204 Package.

*Bonus Bid Deposit*: Each bidder submitting an apparent high bid must submit a bonus bid deposit to the MMS equal to one-fifth of the bonus bid amount for each such bid. Under the authority granted by 30 CFR 256.46(b), the MMS requires bidders to use electronic funds transfer procedures for payment of one-fifth bonus bid deposits for Lease Sale 204, following the detailed instructions contained in the document ''Instructions for Making EFT Bonus Payments'' which can be found on the MMS Web site at *http://www.gomr.mms.gov/homepg/lsesale/204/wgom204.html*. All payments must be electronically deposited into an interest-bearing account in the U.S. Treasury (account specified in the EFT instructions) by 11 a.m. Eastern Time the day following bid reading. Such a deposit does not constitute and shall not be construed as acceptance of any bid on behalf of the United States. If a lease is awarded, however, MMS requests that only one transaction be used for payment of the four-fifths bonus bid amount and the first year's rental.

**Please Note:** Certain bid submitters (i.e., those that are not currently an OCS mineral lease record title holder or designated operator OR those that have ever defaulted on a one-fifth bonus bid payment (EFT or otherwise)) are required to guarantee (secure) their one-fifth bonus bid payment prior to the submission of bids. For those who must secure the EFT one-fifth bonus bid payment, one of the following options may be used: (1) Provide a third-party guarantee; (2) Amend development bond coverage; (3) Provide a letter of credit; or (4) Provide a lump sum payment in advance via EFT. The EFT instructions specify the requirements for each option.

*Withdrawal of Blocks*: The United States reserves the right to withdraw any block from this lease sale prior to issuance of a written acceptance of a bid for the block.

*Acceptance, Rejection, or Return of Bids*: The United States reserves the right to reject any and all bids. In any case, no bid will be accepted, and no lease for any block will be awarded to any bidder, unless the bidder has complied with all requirements of this Notice, including the documents contained in the associated FNOS 204 Package and applicable regulations; the bid is the highest valid bid; and the amount of the bid has been determined to be adequate by the authorized officer. Any bid submitted which does not conform to the requirements of this Notice, the Act, and other applicable regulations may be returned to the person submitting that bid by the RD and not considered for acceptance. The Attorney General may also review the results of the lease sale prior to the acceptance of bids and issuance of leases. To ensure that the Government receives a fair return for the conveyance of lease rights for this lease sale, high bids will be evaluated in accordance with MMS bid adequacy procedures. A copy of current procedures, ''Modifications to the Bid Adequacy Procedures'' at 64 FR 37560 on July 12, 1999, can be obtained from the MMS Gulf of Mexico Region Public Information Unit or via the MMS Internet Web site at *http://www.gomr.mms.gov/homepg/lsesale/bidadeq.html*.

*Successful Bidders*: As required by the MMS, each company that has been awarded a lease must execute all copies of the lease (Form MMS–2005 (March 1986) as amended), pay by EFT the balance of the bonus bid amount and the first year's rental for each lease issued in accordance with the requirements of 30 CFR 218.155, and satisfy the bonding requirements of 30 CFR 256, subpart I, as amended.

Also, in accordance with regulations at 43 CFR, part 42, subpart C, the lessee shall comply with the U.S. Department of the Interior's nonprocurement debarment and suspension requirements and agrees to communicate this requirement to comply with these regulations to persons with whom the lessee does business as it relates to this lease by including this term as a condition to enter into their contracts and other transactions.

*Affirmative Action*: The MMS requests that, prior to bidding, Equal Opportunity Affirmative Action Representation Form MMS 2032 (June 1985) and Equal Opportunity Compliance Report Certification Form MMS 2033 (June 1985) be on file in the MMS Gulf of Mexico Region Adjudication Unit. This certification is required by 41 CFR 60 and Executive Order No. 11246 of September 24, 1965, as amended by Executive Order No. 11375 of October 13, 1967. In any event, prior to the execution of any lease contract, both forms are required to be on file in the MMS Gulf of Mexico Region Adjudication Unit.

*Geophysical Data and Information Statement*: Pursuant to 30 CFR 251.12, the MMS has a right to access geophysical data and information collected under a permit in the OCS.

Every bidder submitting a bid on a block in Sale 204, or participating as a joint bidder in such a bid, must submit a Geophysical Data and Information Statement (GDIS) identifying any processed or reprocessed pre- and post-stack depth migrated geophysical data and information used as part of the decision to bid or participate in a bid on the block. The GDIS should clearly identify the survey type (2–D or 3–D); survey extent (i.e., number of line miles for 2D or number of blocks for 3D) and imaging type (pre-stack, post-stack and migration algorithm) of the data and information. The statement must also include the name and phone number of a contact person, and an alternate, who are both knowledgeable about the depth data listed, the owner or controller of the reprocessed data or information, the survey from which the data was reprocessed and the owner/controller of the original data set, the date of reprocessing and whether the data was processed in-house or by a contractor. In the event such data and information includes multiple data sets processed from the same survey using different velocity models or different processing parameters, you should identify only the highest quality data set used for bid preparation. The MMS reserves the right to query about alternate datasets and to quality check and compare the listed and alternative data sets to determine which data set most closely meets the needs of the fair market value determination process.

The statement must also identify each block upon which a bidder participated in a bid but for which it does not possess or control such depth data and information.

In the event your company supplies any type of data to the MMS, in order to get reimbursed, your company must be registered with the Central Contractor Registration (CCR) at *http://www.ccr.gov*. This is a requirement that was implemented on October 1, 2003, and requires all entities doing business with the Government to complete a business profile in CCR and update it annually. Payments are made electronically based on the information contained in CCR. Therefore, if your company is not actively registered in CCR, the MMS will not be able to reimburse or pay your company for any data supplied.

Please refer to NTL No. 2003–G05 for more detail concerning submission of the Geophysical Data and Information Statement, making the data available to the MMS following the lease sale, preferred format, reimbursement for costs, and confidentiality.

Dated: July 13, 2007.

**Walter D. Cruickshank,**

*Acting Director, Minerals Management Service.*

[FR Doc. E7–14114 Filed 7–19–07; 8:45 am]

**BILLING CODE 4310–MR–P**

---

## DEPARTMENT OF LABOR

### Office of Disability Employment Policy

**[SGA 07–05]**

### National Technical Assistance and Research Center To Promote Leadership for Employment and Economic Independence for Adults With Disabilities; Solicitation for Cooperative Agreement

*Announcement Type:* New Notice of Availability of Funds and Solicitation for Grant Application (SGA) for Cooperative Agreement.

*Funding Opportunity Number:* SGA 07–05.

*Catalogue of Federal Domestic Assistance (CFDA) Number:* 17.720.

**DATES:** Applications must be received by August 20, 2007.

*Executive Summary:* The U.S. Department of Labor (''DOL'' or ''Department''), Office of Disability Employment Policy (''ODEP''), announces the availability of up to $2.35 million to fund a cooperative agreement to establish a National Technical Assistance and Research Center to Promote Leadership for Increasing Employment and Economic Independence for Adults with Disabilities with a 24-month period of performance. In addition, this initiative may be funded for up to three (3) additional option years depending on performance, identified need, and the availability of future funding.

This National Technical Assistance and Research Center will focus on building leadership capacity at the Federal, State, and local levels to increase employment and economic self-sufficiency for adults with disabilities. ODEP is also funding a technical assistance and research center focusing on youth with disabilities through a separate competition.

Seventeen years after enactment of the Americans with Disabilities Act (ADA), there is no barrier more challenging to the realization of the American dream for citizens with disabilities than unemployment and its resulting poverty, which precludes meaningful community participation. Multiple demonstrations have documented that people with barriers to employment resulting from a disability can become successfully employed with appropriate supports and the customization of employment responsibilities. With Federal investment of millions of dollars into such research and demonstrations, valuable data and successful practices have emerged. But their findings are not widely disseminated or utilized, and their impact on policy and practice within states is too often not evident.

In recognition of this fact, over the last decade, the Federal Government has taken proactive steps to increase employment and otherwise resolve barriers to employment for adults with disabilities. Multiple Executive Orders have been issued focusing on employment and disability (such as Executive Order 13078: Increasing Employment of Adults With Disabilities, 1998), and on increasing the opportunity for individuals with disabilities to become qualified Federal employees (Executive Order 13163, Increasing the Opportunity for Individuals With Disabilities To Be Employed in the Federal Government, 2000).

The Federal Government has also required Federal agencies to establish procedures providing reasonable accommodation of work-related disabilities (Executive Order 13164, Requiring Federal Agencies To Establish Procedures To Facilitate the Provision of Reasonable Accommodation, 2000) and to increase community-based alternatives for individuals with disabilities (Executive Order 13217, Community-Based Alternatives for Individuals With Disabilities, 2001). These Executive Orders are in addition to laws prohibiting discrimination in employment under Section 504 of the Rehabilitation Act of 1973 and Title I of the ADA. Further, the New Freedom Initiative, established in 2001 by President George W. Bush, brought heightened focus to and action in disability policy throughout the Federal sector across numerous areas, including employment.

Yet despite these multiple efforts, employment outcomes for adults with disabilities are still far below that of the general adult population. The U.S. Census Bureau's American Community Survey in 2005 estimated that among the more than 21 million people with disabilities aged 16–64, only 8.5 million, or 37.5 percent, were employed (*http://www.disabilitystatistics.org*, downloaded 5/15/07). Of the people with disabilities employed aged 16–64, 49.9 percent of men with disabilities are employed as opposed to 80.9 percent of working-age men without a disability. For women of working age, 34.2 percent of women with disabilities are employed, compared with 68.3 percent of women without disabilities. Not surprisingly, the poverty rate among people with disabilities from 16 to 64 years old was 24.6 percent, almost triple the rate for those without disabilities (9.3 percent).

Effectively addressing the complex and significant barriers to employment and economic self-sufficiency faced by adults with disabilities requires the use of multiple strategies and the active involvement of many stakeholders, including Federal, State and local governments, non-governmental organizations, financial institutions, consumers, and employers. To address this situation, ODEP is funding a national technical assistance and research center (the Center) to build capacity within and across both generic and disability-specific service-delivery systems to provide transformational leadership in service to adults with disabilities, and thus increase their employment and economic self-sufficiency.

The Center will conduct research, develop and disseminate information, and provide technical assistance and training in five targeted goal areas defined in this solicitation. These goal areas have been identified through six years of ODEP research as critical leadership areas for improving systems capacity to effectively serve adults with disabilities and increase their employment and economic self-sufficiency. These targeted goal areas include the following:

1. Increasing partnership and collaboration among and across generic and disability-specific systems that provide employment or employment-support services. This partnership and collaboration should produce more effective and efficient services through leveraging resources and funding across multiple systems.

2. Increasing use of self-direction in service and integration of funding among and across cross-generic and disability-specific systems, including the blending and braiding of resources and funding across systems and programs, and the use of self-directed accounts providing choice and control to the individual job seeker.

3. Increasing economic self-sufficiency through leveraging relevant generic and disability-specific tax incentives, financial education, social security work incentives, benefits planning, and other strategies for enhancing profitable employment resulting in the ability of people with disabilities to accrue assets and resources through employment.

4. Increasing the use of universal design as the framework for the organization of employment policy and the implementation of employment services.

5. Increasing the use of customized and other forms of flexible work options for individuals with disabilities and others with complex barriers to employment.

In addition, the Center will provide rapid response on request to ODEP in areas related to employment and disability, and otherwise support ODEP as requested in its efforts to develop policy recommendations for increasing employment and economic self-sufficiency for adults with disabilities.

In meeting each goal area, applicants must provide information on strategies they will undertake for advancing knowledge development and utilization, including describing specific research and technical assistance and training activities. In addition, applicants must describe how they will effectively disseminate policy knowledge, research findings, and successful practices through and within various networks of State and local systems' personnel, particularly leadership personnel, and other relevant stakeholder communities (including, but not limited to consumers, employers, and providers of employment and asset development services). They should also describe how they will encourage and monitor the translation and utilization of such knowledge, research, and successful practices.

**I. Funding Opportunity Description**

*1. Description and Purpose*

ODEP will award one cooperative agreement to establish a national technical assistance and research center for increasing employment and economic independence for adults with disabilities. The overall purpose of this effort is to build leadership and partnership across workforce development, economic development, and relevant partner agencies and systems, including generic and disability-specific agencies and systems, so that they work together strategically and effectively to increase employment outcomes and economic self-sufficiency for adults with disabilities. The Center will: Conduct research to identify, validate, document, and otherwise promote effective practices and policies in targeted goal areas; develop and disseminate information; provide technical assistance; encourage collaboration and partnership across State and local generic and disability-specific systems and programs, both public and private; and work with States and localities on multiple strategies in targeted goal areas for improving employment outcomes and economic self-sufficiency for adults with disabilities. Activities of the Center must be based on the assumptions that: people with disabilities have the ability to make and implement decisions (with support as appropriate) about their own work life, and that they have the ability to mobilize and develop resources (with support as necessary) to move from poverty and dependency to independence and productivity through employment. They must also be based on the assumption that there is a need for multiple generic and disability-specific systems and services to effectively partner across traditional boundaries. In accomplishing these goals, the Center will provide transformational leadership for translating innovation and emerging successful solutions from isolated demonstrations to systemic practices, and will act as a voice for elevating the discussion about employment and disability nationally.

The Center's research-related activities will improve systems capacity to provide leadership for increasing employment and economic self-sufficiency at the State and local level in targeted goal areas, and must include the development of policy-related recommendations for consideration across agencies and systems. It must include, but is not limited to, the following activities:

- Implementing research, demonstration activities, and otherwise developing evidence (either through qualitative and quantitative methods, as appropriate) in targeted goal areas for effective models and approaches to increasing employment and economic self-sufficiency for adults with disabilities;

- Promoting and documenting the impact of actions of key leadership personnel at the State and local levels across public and private systems and agencies utilizing employment approaches in targeted goal areas in select states;

- Conducting an analysis of the interaction between and among various strategies and approaches in targeted goal areas as they exist in public policy, both nationally and in select states; and

- Developing evidence across public and private systems and agencies of effective leadership strategies in targeted goal areas.

The Center's technical assistance and dissemination activities must include, but are not limited to, the following:

- Developing evidence-based information and materials (including multi-media materials, curricula, and other relevant accessible products) in targeted goal areas for use in increasing leadership capacity for advancing employment and economic self-sufficiency for adults with disabilities;
- Preparing and disseminating appropriate reports and documents related to targeted goal areas in publications including, but not limited to, peer-reviewed journals;
- Providing intensive technical assistance, training, and information in targeted goal areas to ODEP's grantees including documenting the impact of such actions;
- Providing information to educate relevant stakeholders, including State and local policymakers, systems personnel, key leadership personnel, educators, and other relevant individuals and groups about changes in policy and practice needed in order to increase employment and economic self-sufficiency for adults with disabilities, and the evidence supporting action in targeted goal areas under this solicitation;
- Providing technical assistance, training, and information to increase understanding and utilization by relevant workforce systems and agencies of strategies developed in targeted goal areas;
- Serving as a repository and dissemination center for materials and effective practices developed by current and former ODEP grantees; and
- Creating and maintaining a user-friendly Web site with relevant information and documents in a form that meets a government or industry-recognized standard for accessibility.

The Center's collaboration and partnership activities must include, but are not limited to:

- Developing evidence on strategies for, and results of, effective interagency partnership and collaboration between and among Federal, State, and local systems and agencies, both generic and disability-specific, that effectively leverage and maximize available resources in ways that provide choice, control and self-direction to individual job seekers; and
- Developing, maintaining, and documenting relationships that result in partnerships and collaborations to foster employment and economic self-sufficiency for adults with disabilities. Partners may include but are not limited to the following entities:

(1) State departments and agencies across generic and disability-specific systems such as departments of Labor, Economic Development, Vocational Rehabilitation, Veterans Affairs, Mental Health, Medicaid, Mental Retardation/Developmental Disabilities, Education, and Temporary Assistance for Needy Families (TANF); and Governors' Committees on Employment of People with Disabilities and Developmental Disability Councils;

(2) Local Work Investment Act (WIA) service providers, employment service providers, local One-Stop Career Centers and the Veterans Employment and Training Service; State and local financial services entities; social security benefits planning and assistance programs; community and faith-based organizations and disability organizations; community colleges and other training entities; and providers of employment-related supports, including public housing and transportation authorities;

(3) Employers and their professional networks;

(4) Federal agencies including the Departments of Labor, Health and Human Services, Commerce, Housing and Urban Development, Treasury, Transportation, Education, and Veterans' Affairs; the Small Business Administration and Social Security Administration; and other generic and disability-specific agencies that work in areas related to improving employment and economic self-sufficiency for adults with disabilities and others with complex barriers to employment; and

(5) ODEP-sponsored and other Federal technical assistance projects that provide information about, or work in areas related to, employment (including self employment), economic development, and/or enhancing employment profitability through use of relevant tax incentives, financial literacy, work incentives, benefits assistance and related areas).

Additionally, the Center will work with ODEP to implement on-site, intensive, targeted technical assistance and research in two pilot states or economic development regions. The pilot project will be competitively selected by the third quarter of year 1 of Center activities. Staff and expert consultant time and project resources dedicated to provide technical assistance, research, and training support to the competitively selected states or regions will be negotiated with ODEP as part of the Cooperative Agreement within thirty (30) days of the date of the award in year 1. However, it is expected that a minimum of $600,000 is to be spent on the above component of the work plan. Year 1 activities will include the development of targeted technical assistance materials, a work plan (to be approved by ODEP) for this component of Center activities, and design and implementation of a competitive selection process for the states or economic development regions. Intensive, on-site, targeted activities will begin immediately with the competitively selected states or regions no later than the first quarter of year 2 of Center activities, and will focus on implementation of goal areas defined in this SGA throughout the states or economic development regions. Additional funding for this activity will be dedicated to this component of Center activities during years 3–5 pending ODEP's exercise of the option periods provided herein, and the availability of funds and adequacy of performance.

The remainder of the funding that is provided is to be spent on carrying out the general technical assistance, research, and training functions in targeted goal areas described previously.

*2. Background*

The Office of Disability Employment Policy (ODEP) provides national leadership by developing and influencing disability-related employment policy and practice. A five-year strategic plan guides ODEP in achieving its mission by identifying long-term strategic and outcome goals as well as short-term intermediate and performance goals. In addition to measuring agency performance, as required by the Government Performance and Results Act (GPRA), the strategic plan sets forth a road map for prioritizing the formulation and dissemination of innovative employment policies and practices to service-delivery systems and employers.

ODEP's annual goal is to build knowledge and advance disability employment policy that affects and promotes systems change. The agency's long- and short-term goals focus efforts on initiatives that bring about this level of change. In short, ODEP develops policies and strategies that will:

- Enhance the capacity of service-delivery systems to provide appropriate and effective services and supports to youth and adults with disabilities;
- Increase planning and coordination within service-delivery systems to develop and improve systems, processes, and services;
- Improve individualization of services to better assist youth and adults with disabilities in seeking, obtaining,

and retaining employment or self-employment;

- Increase employer access to supports and services to meet their employment needs;
- Increase the quality of competency-based training for service-delivery systems;
- Increase the adoption of universal strategies for service provision; and
- Develop partnerships with and among critical stakeholders to effectively leverage available resources, and facilitate implementation of practices and policies that increase employment and self-employment opportunities as well as the recruitment, retention, and promotion of adults with disabilities.

Three measures inform ODEP of its annual progress in meeting its three goals under the Government Performance and Results Act: (1) The number of policy-related documents; (2) the number of formal agreements; and (3) the number of effective practices. These performance results support achievement of the following intermediate outcome goals: accessible employment resources; coordinated programs, processes, and services; and adoption of effective practices.

Achievement of these intermediate outcome goals, in turn, supports achievement of the long-term service-delivery systems outcome goals, which are marked by increases in these areas: Capacity of service-delivery systems; planning and coordination within service-delivery systems; and employer access to supports and services for recruitment, retention, and promotion of adults with disabilities.

On February 1, 2001, in announcing the New Freedom Initiative (NFI), President George W. Bush explicitly recognized that in today's global economy, America must be able to draw on the talents and creativity of all its citizens, and that people with disabilities represent valuable, largely untapped human capital. The NFI represents an important step towards ensuring that all Americans have the opportunity to learn and develop skills, engage in productive work, choose where to live, and participate in community life.

The timeliness of the proposed effort to provide and promote leadership for employment and economic independence for adults with disabilities is reinforced by the demographic workforce issues that led to the New Freedom Initiative and the continuing challenges faced by workforce systems. Potential and current workers with disabilities fall within all of the following demographic groups: Returning veterans, mature workers, baby boomers, Generations X and Y, people with limited English proficiency, the chronically homeless, and migrants. In addition, the decline in the number of workers due to the potential retirement of millions of baby boomers; the desires and needs of millions of other baby boomers who choose to stay in the workforce, but on their own terms; the demands of Generation X and Y workers who expect companies to offer flexible work options; the complex needs of veterans with service-connected injuries; the poverty levels, lack of education, and skills' competencies of many people with limited English proficiency; migrant workers lacking higher-level skills, to name some of the key demographic issues, compel companies to retool their recruitment and retention strategies, and demand workforce systems to provide leadership to meet these needs.

Related to these issues is the fact that from 2001 through 2006 ODEP implemented several research initiatives to develop and document innovative and universal approaches to improving employment outcomes for adults with disabilities. In these ODEP initiatives, a total of 26 Customized Employment and Workforce Action (Olmstead) grantees were funded for periods of time ranging from three to five years. Central to the assumptions guiding the creation of these grants was the recognition of the importance of flexibility in the way work is organized and performed, the importance of partnership between and among generic and disability-specific systems, the use of mechanisms to promote self-direction and economic self-sufficiency, and the universality and applicability of many of the successful approaches being tested with other populations of people with barriers to employment.

Importantly, these projects were charged with operating as part of the workforce system and developing while demonstrating not only that certain system change is beneficial to outcomes achieved—but that such changes impact how services are organized and provided in a way that is often universal for other workforce customers. The lead service system for the initiatives was the One-Stop Career Centers operated under the Workforce Investment Act (WIA). Overall, these projects were expected to: increase the capacity of service-delivery systems to effectively serve people with disabilities and other ''hard-to-serve'' populations; increase planning and coordination within and across service-delivery systems within the state, including generic as well as disability-specific systems; increase employment outcomes through the use of customized strategies for achieving employment; and develop policy recommendations with broad applicability based on the demonstrated evidence gathered through implementation of grant activities. Additional information about these grant initiatives can be found on ODEP's Web site: *http://www.dol.gov/odep/categories/workforce/.*

Several key findings resulting from these research initiatives include the pivotal importance of the following in promoting positive systems change that results in increased employment and economic self-sufficiency for adults with disabilities:

- Partnership and Collaboration: Collaboration and partnership development was the primary innovation and the foundation of all other systems change efforts across both initiatives. Whether considering policy, resource allocation, or service integration, effective partnerships and collaborative efforts were at the base of every best practice. Collaborative efforts hinged on attaining a shared understanding between and among systems, and the translation of the partnership relationship into written, measurable goals that positively affected each system and its customers.
- Universal Design: The importance of universal design and the use of universal strategies in serving job seekers with disabilities emerged as pivotal for improving access to the programs and services of the workforce development system. Universal design within the workforce development system refers to the design of environments, products, and communication practices as well as the delivery of programs, services, and activities that meet the needs of all customers of the system. ODEP's research documented that One-Stops are incorporating elements of universal design in the way they organize and deliver their services, organize their physical space, and develop the culture of their environments. This universal design incorporation includes addressing disability within the broader concept of diversity and viewing it as one facet of a more sweeping mandate to ensure access to workforce development services for all customers.
- Leveraging Resources: Another central finding of ODEP's research was that over time, collaboration with all types of organizations and agencies increased and resulted in opportunities for leveraging expertise and resources. No single partner or source of funds could adequately respond to the potential spectrum of needs of job

seekers with complex barriers to employment, including disability. Leveraging resources was facilitated at both the systems and individual level, and the blending or braiding of funds across systems became instrumental in the ability of grantees to support a range of job seekers, maximize their own resources, and share the scope of what it takes to effectively provide workforce development services.

Additional findings identified the importance of leveraging various existing tax incentives, financial education, work incentives, and other strategies in order to maximize financial advantage and otherwise enhance profitable employment resulting from work for people with disabilities. Such individuals are no different than any other citizen in their desire to work and advance their economic status. Yet many public policies create barriers to work and economic self-sufficiency for people with disabilities by limiting their ability to accrue assets and maintain critical disability benefits. Numerous work incentives and other strategies exist to assist with maximizing the economic benefits of work for people with disabilities, but these remain underutilized. Developing models of partnership among disability and community-based organizations, One-Stop Career Centers, and local tax and financial institutions will ultimately assist workers with disabilities access to mainstream services, promote their self-determination and economic self-sufficiency, and otherwise enable their employment to positively impact their ability to fully participate in their communities. As the workforce development system continues to increase participation of individuals with disabilities in the labor force, development of models utilizing multiple tax incentives and other strategies that enable people with disabilities to maximize the financial advantage of work are critical. This area holds great promise for assisting people to permanently move off welfare and Social Security benefits, out of poverty, and into the economic mainstream through employment.

Finally, a critical finding across these grant initiatives was the importance of key leadership personnel for promoting positive change at the State and local level across both public and private systems and programs. Understanding and ''buy-in'' on the part of key leaders was found to be essential to the success of long-term, effective, systemic change (*Customized Employment: Employers and Workers Creating a Competitive Edge. Summary Report of Customized Employment and Workforce Action Grants. Boston: Institute for Community Inclusion/UCED. University of Massachusetts at Boston, 2007 in press*).

The impending changes in the workforce make it imperative for our nation to address the significant rate at which adults with disabilities continue to be out of the work force. Isolated demonstrations of success must be translated into broader replication and adoption at the State and local level. The mainstream infrastructure of our states and communities, both generic and disability-specific, must fashion new ways of working in partnership. The research and technical assistance effort proposed herein will support this effort by increasing leadership capacity in five targeted goal areas identified in this solicitation that have been validated through prior research as pivotal in creating positive change for people with disabilities. In addition, this effort will expand the knowledge-base of existing effective practices for increasing employment and economic self-sufficiency for adults with disabilities by intensively targeting technical assistance for implementation of identified successful practices in a number of states, and by providing proactive support, training, and dissemination of other relevant useful information nationally.

The technical assistance to be provided will build upon ODEP's prior research and technical assistance efforts which focused on promoting increased understanding that:

- Increasing employment and economic self-sufficiency for adults with disabilities requires meaningful partnerships across generic and disability-specific systems in both the public and private sector;
- The use of universal design as a framework for organization and implementation of services benefits, not just people with disabilities, but other job seekers with complex barriers to employment;
- Leveraging resources across generic and disability-specific systems can enable the work force system to more effectively respond to the varying needs of job seekers with disabilities and maximize their own systems resources;
- The use of customized employment strategies and other forms of flexible work options can result in integrated, competitive employment for individuals with disabilities and others with complex barriers to employment; and
- Economic self-sufficiency for workers with disabilities is created not by the earning of wages alone, but by leveraging existing tax incentives, financial education, work incentives, and other strategies including, but not limited to, tax incentives for individuals and business, work incentives under Social Security, and matched savings accounts.

*3. Definitions*

Definitions for purposes of this solicitation include:

- Universal Design: Universal Design is defined as the design of environments, products, and communication practices, as well as the delivery of programs, services, and activities, to meet the needs of all customers of the work force development system.
- Customized Employment: Customized employment is a process for individualizing the employment relationship between a job seeker and/or employee and an employer in ways that meet the needs of both, based on an individualized negotiation (including negotiation of the responsibilities and requirements of the job) that addresses the strengths, conditions, and interests of the job seeker and/or employee, and the identified business needs of the employer. Use of customized employment strategies results in a job in a competitive, integrated setting that pays minimum wage or above.

## II. Award Information

*Estimated Available Funds:* The full $2,350,000 for the initial 24-month period of performance will be awarded in 2007.

*Period of Performance:* 24 months from date of award with up to three (3) additional option years depending on performance, identified need, and the availability of future funding.

The U.S. Department of Labor (''DOL'' or ''Department''), Office of Disability Employment Policy (''ODEP''), announces the availability of up to $2,350,000 to fund a national technical assistance and research Cooperative Agreement.

**Note:** Selection of an organization as a Grantee does not constitute approval of the grant application as submitted. Before the actual grant is awarded, DOL may enter into negotiations about such items as program components, staffing (including key project staff and consultants), funding levels, and administrative systems in place to support grant implementation. If the negotiations do not result in a mutually acceptable submission, the Grant Officer reserves the right to terminate the negotiation and decline to fund the application.

Because ODEP plans to make this award in the form of a cooperative agreement, DOL will have substantial involvement in the administration of the agreement. Such DOL involvement will consist of:

(1) Approval of any sub-contract awarded by the Grantee after the grant award;

(2) Participation in site visits to project areas;

(3) Providing advice and consultation to the Grantee on specific program criteria;

(4) Providing the Grantee with technical and programmatic support, including training in DOL monitoring and evaluation systems, and standard procedures regarding DOL management of cooperative agreements;

(5) Reviewing, at reasonable times, all documents pertaining to the project, including status and technical progress reports, and financial reports. ODEP will provide the format for the reports;

(6) Discussing administrative and technical issues pertaining to the project;

(7) Approving all key personnel decisions, sub-contractors, and consultants;

(8) Approving all fact sheets, training materials, press releases, and publicity-related materials regarding the project;

(9) Approving all content for online resources developed through project activities, including clearing concepts for material production and final document production; and

(10) Drafting terms of reference for, and participating in project evaluations.

## III. Eligibility Information

### *1. Eligible Applicants*

Eligible applicants are consortia which may include a combination of any two or more of the following: Public/private non-profits or for-profit organizations (including community and faith-based organizations) and universities and colleges all with demonstrated appropriate experience in providing technical assistance, and conducting research and demonstrations in targeted goal areas defined in this solicitation for increasing employment and economic self-sufficiency for adults with disabilities. The demonstrated expertise required should include, but not be limited to:

- The work force development system, including both policy and practice, related to individuals with disabilities and others with complex barriers to employment, and the use of universal design features and strategies throughout physical and programmatic implementation of work force development services;
- The integration/partnership of work force development and other generic and disability-specific systems including leveraging and blending of funds and resources across systems, and the use of self-directed accounts providing choice and control to the individual job-seeker;
- The use of customized employment solutions for individuals with complex barriers to employment and their employers;
- The use of strategies for enhancing profitable employment and financial advantage for adults with disabilities, including but not limited to, tax incentives for individuals and business, individual development accounts, financial literacy training, and work incentives and benefits assistance available through Social Security; and
- Providing leadership development at the State and local implementation level, including building partnership and collaboration across generic and disability-specific systems and programs.

There must be a prime or lead member of the consortium who is responsible for overall grant management and serves as the fiscal agent. All applications must clearly identify the lead grant recipient and fiscal agent, as well as all other members of the consortium including consultants applying for the grant. In addition, the application must identify the relationship between all of the members of the consortium.

According to section 18 of the Lobbying Disclosure Act of 1995, an organization, as described in section 501(c)(4) of the Internal Revenue Code of 1986, that engages in lobbying activities will not be eligible for the receipt of Federal funds constituting an award, grant, or loan. See 2 U.S.C. 1611; 26 U.S.C. 501(c) (4). Funding restrictions apply. See Section IV (5).

### *2. Cost Sharing*

Cost sharing, matching funds, and cost participation are not required under this SGA. However, leveraging of public and private resources to foster inclusive service-delivery and achieve project sustainability is highly encouraged and included under evaluation criteria. See V (1) (b) (9).

### *3. Other Eligibility Requirements*

Legal rules pertaining to inherently religious activities by organizations that receive Federal Financial Assistance:

- Neutral, non-religious criteria that neither favor nor disfavor religion will be employed in the selection of grant recipients and must be employed by grantees or in the selection of sub-awardees.
- The government is generally prohibited from providing direct financial assistance for inherently religious activities.[1]

## IV. Application and Submission Information

### *1. Addresses To Request Application Package*

This SGA contains all the information and forms needed to apply for this grant funding. Application announcements or forms will not be mailed. The **Federal Register** may be obtained from your nearest government office or library. In addition, a copy of this notice and the application requirements may be downloaded from ODEP's Web site at *http://www.dol.gov/odep* and at *http://www.grants.gov.* Applicants submitting proposals online are requested to refrain from mailing a hard copy application as well. It is strongly recommended that applicants using *http://www.grants.gov* immediately initiate and complete the ''Get Started'' registration steps at *http://www.grants.gov/GetStarted.* These steps may take multiple days to complete, and this should be factored into plans for electronic submission in order to avoid facing unexpected delays that could result in the rejection of an application. If submitting electronically through *http://www.grants.gov* the application must be saved as .doc, .pdf, or .txt files. If additional copies of the standard forms are needed, they can also be downloaded from: *http://www.whitehouse.gov/omb/grants/grants_forms.html.*

### *2. Content and Form of Application Submission*

*General Requirements:* Applicants must submit one (1) paper copy with an original signature and two (2) additional paper copies of the signed proposal. To aid with the review of applications, DOL also requires applicants to submit an electronic copy of their proposal's Sections II (Executive Summary) and III (Project Narrative) on disc or compact disc (CD) using Microsoft Word. The application (not to exceed 30 pages for Section III), must be double-spaced with standard one-inch margins (top, bottom, and sides) on 8½ × 11-inch paper, and

[1] In this context, the term direct financial assistance means financial assistance that is provided directly by a government entity or an intermediate organization, as opposed to financial assistance that an organization receives as the result of the genuine and independent private choice of a beneficiary. In other contexts, the term ''direct'' financial assistance may be used to refer to financial assistance that an organization receives directly from the Federal Government (also known as ''discretionary'' assistance), as opposed to assistance that it receives from a State or local government (also known as ''indirect'' or ''block'' grant assistance). The term ''direct'' has the former meaning throughout this SGA.

must be presented on single-sided and numbered pages. A font size of at least twelve (12) pitch is required throughout. All text in the application narrative, including titles, headings, footnotes, quotations, and captions must be double-spaced (no more than three lines per vertical inch); and, if using a proportional computer font, must be in at least a 12-point font, and must have an average character density no greater than 18 characters per inch (if using a non-proportional font or a typewriter, must not be more than 12 characters per inch). Applications that fail to meet these requirements will be considered non-responsive.

Cooperative Agreement Mandatory Application Requirements

The three required sections of the application are titled below and described thereafter:

Section I—Project Financial Plan (No page limit).
Section II—Executive Summary—Project Synopsis (Not to exceed two (2) pages).
Section III—Project Narrative (Not to exceed 30 pages).

The mandatory requirements for each section are set forth below. Applications that fail to meet the stated mandatory requirements for each section will be considered non-responsive.

*Section I. Project Financial Plan (Budget):* The Project Financial Plan will not count against the application page limits. Section I of the application must include the following:

(1) Completed ''SF–424—Application for Federal Assistance.''

Please note that, beginning October 1, 2003, all applicants for Federal grant and funding opportunities are required to include a Dun and Bradstreet (DUNS) number with their application. See OMB Notice of Final Policy Issuance, 68 Fed. Reg. 38402 (June 27, 2003). The DUNS number is a nine-digit identification number that uniquely identifies business entities. There is no charge for obtaining a DUNS number (although it may take 14–30 days). To obtain a DUNS number, access the following Web site: *http://www.dunandbradstreet.com* or call 1–866–705–5711. Requests for exemption from the DUNS number requirement must be made to the Office of Management and Budget. The Dun and Bradstreet Number of the applicant should be entered in the ''Organizational Unit'' section of block 8 of the SF–424. (See Appendix A of this SGA for required form.)

(2) The SF–424 must contain the original signatures of the legal entity applying for cooperative agreement funding and two additional copies of the signed SF–424. The individual signing the SF–424 on behalf of the applicant must represent and be able to legally bind the responsible financial and administrative entity for a cooperative agreement should that application result in an award. Applicants shall indicate on the SF–424 the organization's Internal Revenue Service (IRS) status (e.g. 501(c)(3) organization), if applicable.

(3) Completed SF–424A—Budget Information Form by line item for all costs required to implement the project design effectively. (See Appendix B of this SGA for required forms.)

(4) DOL Budget Narrative and Justification that provides sufficient information and methodologies used to support the reasonableness of the costs included in the budget in relation to the service strategy and planned outcomes, including continuous improvement activities.

The DOL Budget Narrative and Justification must include a detailed cost breakout of each line item on the Budget Information Sheet. Please label this page or pages the ''Budget Narrative'' and ensure that costs reported on the SF 424A correspond accurately with the Budget Narrative; the Budget Narrative must include, at a minimum, Personnel Costs—Applicants must provide a breakout of all personnel cost b position, title, annual salary rates, and percent of time of each position to be devoted to the proposed project; Fringe Benefits—Applicants must provide an explanation and breakout of fringe benefit rates and associated charges that exceed 35% of salaries and wages; Explanation of Costs and Methodologies—Applicants must provide an explanation of the purpose and composition of, and methodology used to derive the costs of each of the following: Personnel costs, fringe benefits, travel, equipment, supplies, contracts, and any other costs. The applicant must include costs of any required travel described in this Solicitation; describe all costs associated with implementing the project that are to be covered with cooperative agreement funds. The budget must support the travel and associated costs of sending representatives to both a post-award conference and periodic meetings with ODEP staff in Washington, D.C. (at least once per quarter), at a time and place to be determined. In addition to other administrative requirements identified in section VI(2) of this SGA, the applicant must comply with the ''Uniform Administrative Requirements for Grants and Cooperative Agreements to State and Local Governments'' (also known as OMB Circular A–102), codified at 29 CFR part 97, or ''Grants and Agreements with Institutions of Higher Education, Hospitals, and Other Non-Profit Organizations'' (also known as the ''Common Rule'' or OMB Circular A–110), codified at 2 CFR part 215 and 29 CFR part 95.

In addition, the budget submitted for review by DOL must include, on a separate page, a detailed cost analysis of each line item. The costs listed in the detailed cost analysis must comply with the applicable OMB cost principles circulars, as identified in 29 CFR 95.27 and 29 CFR 97.22(b). Justification for administrative costs must be provided. Approval of a budget by DOL is not the same as the approval of actual costs. The applicant must also include the Assurances and Certifications Signature Page (Appendix C) and the Survey on Ensuring Equal Opportunity for Applicants (Appendix D).

*Section II. Executive Summary*—Project Synopsis: The Executive Summary is limited to no more than two single-spaced, single-sided pages on 8½ × 11-inch paper with standard margins throughout. The project synopsis must identify the following:

(1) The lead entity;

(2) The list of consortium members and consultants, as appropriate; and

(3) An overview of how the applicant will carry out the technical assistance and research activities described in Section I of this solicitation.

*Section III. Project Narrative:* The DOL Cooperative Agreement Project Narrative is limited to no more than thirty (30), 8½ × 11″ pages, double-spaced with standard one-inch margins (top, bottom, and sides), and must be presented on single-sided, numbered pages. This page limit does not apply to Section I, the Project Financial Plan (Budget), Section II, the Executive Summary and the Appendices (the assurances and certifications, resumes, a bibliography or references, and the documentation of commitment/formal agreement/letters of support and other materials relevant to the application). A page is 8½ × 11″ (on one side only) with one-inch margins (top, bottom, and sides). All text in the application narrative, including titles, headings, footnotes, quotations, and captions must be double-spaced (no more than three lines per vertical inch); and, if using a proportional computer font, use no smaller than a 12-point font, and an average character density no greater than 18 characters per inch (if using a non-proportional font or a typewriter, do not use more than 12 characters per inch).

Applications must include a Project Narrative that addresses the work proposed to be accomplished under the Cooperative Agreement, and the evaluation/selection criteria in Part V(1) that will be used by reviewers in evaluating the application.

The successful applicant will be a Technical Assistance and Research Consortium and will describe in their Project Narrative their innovative and comprehensive plan for accomplishing the technical assistance and research activities described in Part I(1) Description and Purpose, and Part I(2) Background.

The Project Narrative must:

(1) Identify members of the consortium (including the lead entity, other consortium members, and key consultants) and provide documentation (such as letters of intent and memorandum of agreement which will be included in an Appendix) of a formal agreement of participation;

(2) Demonstrate each of the consortium members' and key consultants' relevant experience and expertise;

(3) Identify how the applicant proposes to disseminate research findings and technical assistance products; and

(4) Identify how the applicant proposes to monitor the implementation and/or adoption of technical assistance and training and otherwise provide evidence of project impact.

Each Project Narrative must include:

(1) A detailed 24-month management plan for project goals, objectives, and activities;

(2) A detailed 24-month timeline for project activities, including producing and submitting a final report;

(3) A detailed outline for an evaluation of the project (see Section V(1)(f) for more information);

(4) A description of procedures and approaches that will be used to provide ongoing communication, collaboration with, and input from ODEP's Project Officer on all grant-related activities.

(5) A detailed description of how the consortia will work with multiple Federal, State and local public and private entities to implement and monitor implementation of policy recommendations and strategies identified in carrying out project activities; and

(6) A detailed description of measures that will be taken to ensure that elements of the project's technical assistance will be sustained following the completion of project activities.

The Project Narrative must describe the proposed staffing for the project and must identify and summarize the qualifications of the personnel who will carry it out related to the objectives of this solicitation. In addition, the evaluation criteria listed in Section V (1)(c) include consideration of the qualifications, including relevant education, training, and experience, of key project personnel, as well as the qualifications, including relevant education, training and experience, of project consultants or subcontractors. Resumes must be included in the appendices. Key personnel include any individual (whether consortium member or individual consultant or contractor) playing a substantial role in the project. Minimum qualifications should be commensurate with the role identified in the application. In addition, the applicant must specify in the application the percentages of time to be dedicated by each key person on the project.

For each staff person named in the application, documentation of all internal and external time commitments shall be provided. In instances where a staff person is committed on a Federally supported project, the project name, Federal office, program title, the project Federal award number, and the amount of committed time by each project year shall be provided. This information (e.g., Staff: Jane Doe; Project Name: Succeeding in the General Curriculum; Federal office: Office of Special Education Programs; Program title: Field-Initiated Research; Award number: H324C980624; Time commitments: Year 1–30%; Year 2–25% and Year 3–40%) can be provided as an appendix to the application.

In general, ODEP will not reduce time commitments on currently funded grants from the time proposed in the original application. Therefore, ODEP will not consider for funding any application where key staff are bid above a time commitment level that staff have available to bid. Further, the time commitments stated in newly submitted applications will not be negotiated down to permit the applicant to receive a new grant award.

The Project Narrative should also describe how the applicant plans to comply with the employment discrimination and equal employment opportunity requirements of the various laws listed in the assurances section.

*3. Submission Dates, Times and Addresses*

Applications will be accepted commencing July 20, 2007. The closing date for receipt of applications by DOL under this announcement is August 20, 2007.

Applications, including those hand delivered, must be received by 4:45 p.m. (EST) on the closing date at the address specified below. No exceptions to the mailing and hand-delivery conditions set forth in this notice will be granted. Applications that do not meet the conditions set forth in this notice will be considered non-responsive.

Applications must be mailed or hand delivered to: U.S. Department of Labor, Procurement Services Center, Attention: Cassandra Mitchell, Reference SGA 07–05, Room S–4307, 200 Constitution Avenue, NW., Washington, DC 20210. Applications sent by e-mail or telefascimile (FAX) will not be accepted.

*Hand-Delivered Proposals:* Hand-delivered applications will be considered for funding, but must be received by the above specified date and time. Overnight or express delivery from carriers other than the U.S. Postal Service will be considered hand-delivered applications. It is preferred that applications be mailed at least five (5) days prior to the closing date to ensure timely receipt. Failure to adhere to the above instructions will serve as a basis for a determination of non-responsiveness.

Applicants are advised that mail in the Washington, DC area may be delayed due to mail decontamination procedures and may wish to take this information into consideration when preparing to meet the application deadline.

*Late Applications:* Any application received by the designated office after the exact date and time specified will be considered non-responsive, unless it is received before awards are made and it: (a) Is determined that its late receipt was caused by DOL error after timely delivery to the Department of Labor; (b) was sent by U.S. Postal Service registered or certified mail not later than the fifth calendar day before the date specified for receipt of applications (e.g., an application submitted in response to a solicitation requiring receipt of applications by the 20th of the month must have been postmarked by the 15th of that month); or (c) was sent by the U.S. Postal Service Express Mail Next Day Service to addressee not later than 5:00 p.m. at the place of mailing two (2) working days prior to the date specified for receipt of applications. The term ''working days'' excludes weekends and Federal holidays. ''Postmarked'' means a printed, stamped, or otherwise placed impression (exclusive of a postage meter machine impression) that is readily identifiable without further action as having been supplied or affixed on the date of mailing by an employee of the U.S. Postal Service.

*Withdrawal of Applications:* An application that is timely submitted may be withdrawn by written notice or telegram (including mailgram) at any time before an award is made. Applications may be withdrawn in person by the applicant or by an authorized representative thereof, if the representative's identity is made known and the representative signs a receipt for the proposal.

*4. Intergovernmental Review*

This funding opportunity is not subject to Executive Order 12372, ''Intergovernmental Review of Federal Programs.''

*5. Funding Restrictions*

(a) *Funding Levels:* The total funding available for this solicitation is $2,350,000. The Department of Labor reserves the right to negotiate the amounts to be awarded under this competition. Please be advised that requests exceeding the maximum stated amount will be considered non-responsive. Additionally, there will be no reimbursement of pre-award costs.

(b) *Period of Performance:* The period of performance will be for 24 months from the date of the award unless modified. It is expected that the successful applicant will begin program operations under this solicitation immediately upon receiving the ''Notice of Award.''

(c) *Option Year Funding:* Up to three (3) additional option years may be available depending on performance, identified need, and the availability of future funding.

(d) *Indirect Charges:* If indirect charges are claimed in the proposed budget, the recipient must provide on a separate sheet, the following information:

(1) Name and address of cognizant Federal audit agency;

(2) Name, address and phone number (including area code) of the Government auditor;

(3) Documentation from the cognizant agency indicating:

(a) Current indirect cost rate and the base against which the rate should be applied;

(b) Effective period (dates) for the rate; and

(c) Date last rate was computed and negotiated.

(4) If no government audit agency computed and authorized the rate claimed, a proposed rate with justification may be submitted providing a brief explanation of computation, who computed the rate, and the date of the computation. Successful applicants will be required to negotiate an acceptable and allowable rate within 90 days of grant award with the appropriate DOL Regional Office of Cost Determination or with the applicant's cognizant agency for indirect cost rates (See Office of Management and Budget Web site at *http://www.whitehouse.gov/omb/grants/attach.html*). The recipient shall call the Office of Cost Determination at 202–693–4100 for the initial contact.

However, applications claiming an indirect cost rate greater than 15% will not be considered.

**V. Application Review Information**

*1. Evaluation Criteria*

A technical panel will review grant applications against the criteria listed below, on the basis of the maximum points indicated.

(a) Significance of the Proposed Project (10 Points)

In determining the significance of the proposed research, the Department will consider the following factors:

1. The potential contribution of the proposed project to increase knowledge or understanding of problems, issues, or effective strategies for promoting leadership to increase employment and economic self-sufficiency for adults with disabilities;

2. The likelihood that the proposed project will result in systems change or improvement across generic and disability-specific systems;

3. The extent to which the proposed project is likely to build capacity to provide, improve, or expand services that address the needs of the target population as they relate to targeted goal areas in this solicitation;

4. The likely utility of the products (such as information, materials, processes, or techniques) that will result from the proposed project, including the potential for their being used effectively in a variety of other settings;

5. The importance or magnitude of the results or outcomes likely to be attained by the proposed project; and

6. The extent to which the proposed project builds upon prior work done by ODEP and its partners around increasing employment for adults with disabilities, including integration of universal strategies, customized employment, and related policies and practices within and across generic and disability-specific systems.

(b) Project Design (25 Points)

In evaluating the quality of the proposed project design, the Department will consider the following factors:

1. The extent to which the goals, objectives, and outcomes to be achieved by the proposed project are clearly specified and measurable;

2. The extent to which the design of the proposed project includes a comprehensive review of the relevant literature, a detailed plan for project implementation, and the use of appropriate methodological tools to ensure successful achievement of project objectives;

3. The extent to which the proposed project will effectively contribute to increased knowledge, understanding, and utilization of strategies in targeted goal areas by building upon current research, and effective practices;

4. The extent to which the proposed project will be coordinated with similar or related Federal technical assistance efforts, such as research, training, and information efforts;

5. The extent to which the proposed project encourages involvement of relevant experts and organizations including individuals with disabilities and generic systems' personnel;

6. The extent to which performance feedback and continuous improvement are integral to the design of the proposed project;

7. The extent to which the services to be provided by the proposed project are appropriate to the needs of the intended recipients or beneficiaries of those services;

8. The adequacy of the documentation submitted in support of the proposed project to demonstrate the commitment of each entity or individual included in project implementation;

9. The extent to which the proposed project leverages other public and private resources to foster inclusive service delivery and sustainability and provides other concrete evidence of sustainability, including appropriate letters of support included in the appendices; and

10. The extent to which the design of the proposed project includes a comprehensive strategy for providing technical assistance and conducting research to effectively integrate universal design and services, customized employment and flexible work options, and use of tax incentives, work incentives, and other strategies for enhancing employment profitability into the policy and practice of public and private workforce systems (and their public and private partners) nationally.

(c) Organizational Capacity and Quality of Key Personnel (25 points)

Applications will be evaluated based on the extent to which the applicant demonstrates organizational capacity and quality of key personnel to implement the proposed project, including:

1. Demonstrated experience with similar projects providing technical assistance and conducting research relating to targeted goal areas;

2. Qualifications and demonstrated experience of the applicant's key personnel, subcontractors and consultants particularly in targeted goal areas; and

3. Appropriateness of the organization's structure to carry out the project.

(d) Budget and Resource Capacity (10 Points)

In evaluating the capacity of the applicant to carry out the proposed project, ODEP will consider the following factors:

1. The extent to which the budget is adequate to support the proposed project; and

2. The extent to which the anticipated costs are reasonable in relation to the objectives, design, and potential significance of the proposed project.

(e) Quality of the Management Plan (15 Points)

In evaluating the quality of the management plan for the proposed project, ODEP will consider the following factors:

1. The extent to which the management plan for project implementation appears likely to achieve the objectives of the proposed project on time and within budget, and includes clearly defined staff responsibilities, time allocation to project activities, time lines, milestones for accomplishing project tasks, project deliverables, and information on adequacy of other resources necessary for project implementation;

2. The extent to which the management plan appears likely to result in sustainable activities beyond the period of direct Federal investment;

3. The adequacy of mechanisms for ensuring high-quality products and services relating to the scope of work for the proposed project; and

4. The extent to which the time commitments of the project director and/or principal investigator and other key project personnel and/or subcontractors and consultants are appropriate and adequate to meet the objectives of the proposed project.

(f) Quality of the Project Evaluation (15 Points)

In evaluating the quality of the project's evaluation design, including the data to be generated through implementation of project activities, ODEP will consider the following factors:

1. The extent to which the methods of evaluation are thorough, feasible, and appropriate to the goals, objectives, context, and outcomes of the proposed project;

2. The extent to which the design of the evaluation includes the use of objective performance measures and methods that will systematically document the project's intended outputs and outcomes and will produce measurable quantitative and qualitative data;

3. The extent to which the evaluation will provide Federal, State and local government entities with useful information about transition and systems change models suitable for replication or testing in other settings; and

4. The extent to which the methods of evaluation provide measures that will inform ODEP's annual performance goals and measures and ODEP's long-term strategic goals.

*2. Review and Selection Process*

A technical review panel will objectively rate each complete application against the criteria described in this SGA. The panel recommendations to the Grant Officer, including any point scores, are advisory in nature. The Grant Officer may elect to award grants either with or without discussion with the applicant. In situations where no discussion occurs, an award will be based on the signed SF–424 form (see Appendix A), which constitutes a binding offer.

The Grant Officer may consider the availability of funds and any information that is available and will make final award decisions based on what is most advantageous to the government, considering factors such as the advisory recommendations from the grant technical evaluation panel and the geographic distribution of Federally funded grants.

*3. Anticipated Announcement and Award Dates*

Announcement of this award is expected to occur within 30 days of award. The Cooperative Agreement will be awarded by no later than September 28, 2007.

**VI. Award Administration Information**

*1. Award Notices*

The Notice of Award signed by the Grant Officer is the authorizing document and will be provided through postal mail and/or by electronic means to the authorized representative listed on the SF–424 Grant Application. Notice that an organization has been selected as a grant recipient does not constitute final approval of the grant application as submitted. Before the actual grant award, the Grant Officer and/or the Grant Officer's Technical Representative may enter into negotiations concerning such items as program components, funding levels, and administrative systems. If the negotiations do not result in an acceptable submittal, the Grant Officer reserves the right to terminate the negotiation and decline to fund the proposal.

*2. Administrative and National Policy Requirements*

All grantees, including faith-based organizations, will be subject to applicable Federal laws (including provisions of appropriations law), regulations, and the applicable Office of Management and Budget (OMB) Circulars. The grant awarded under this SGA will be subject to the following administrative standards and provisions and requirements applicable to particular entities. The applicant must include assurances and certifications that it will comply with these laws in its grant application. The assurances and certifications are attached as Appendix C.

a. Regulations

29 CFR Parts 31 and 32—Nondiscrimination in Federally Assisted Programs of the Department of Labor (respectively, effectuation of Title VI of Civil Rights Act of 1964, and on the Basis of Handicap in Programs and Activities Receiving or Benefiting from Federal Financial Assistance).

29 CFR Part 35—Nondiscrimination on the Basis of Age in Programs or Activities receiving Federal Financial Assistance from the Department of Labor.

29 CFR Part 36—Nondiscrimination on the Basis of Sex in Education Programs or Activities Receiving Federal Financial Assistance.

29 CFR Part 37—Implementation of the Nondiscrimination and Equal Opportunity Provisions in the Workforce Investment Act of 1998.

29 CFR Part 93—New Restrictions on Lobbying.

29 CFR Part 95—Uniform Administrative Requirements for Grants and Agreements with Institutions of Higher Education, Hospitals and Other Non-Profit Organizations, and with Commercial Organizations, Foreign Governments, Organizations Under the

Jurisdiction of Foreign Governments and International Organizations.

29 CFR Part 96—Federal Standards for Audit of Federally Funded Grants, Contracts and Agreements.

29 CFR Part 97—Uniform Administrative Regulations for Grants to States, Local Governments or Tribes.

29 CFR Part 98—Federal Standards for Government wide Debarment and Suspension (Nonprocurement) and Government wide Requirements for Drug-Free Workplace (Grants).

29 CFR Part 99—Federal Standards for Audits of States, Local Governments, and Non-Profit Organizations.

29 CFR Part 2—General Participation in Department of Labor Programs by Faith-Based and Community Organizations; Equal Treatment of All Department of Labor Program Participants and Beneficiaries.

Applicable cost principles under OMB Circulars A–21, A–87, A–122, or 48 CFR part 31.

b. Travel

Any travel undertaken in performance of this cooperative agreement shall be subject to and in strict accordance with Federal travel regulations.

c. Acknowledgement of DOL Funding

Printed Materials: In all circumstances, the following shall be displayed on printed materials prepared by the Grantee while in receipt of DOL/ODEP grant funding: ''Preparation of this item was funded by the United States Department of Labor through its ODEP Grant No. [insert the appropriate Grant number].''

All printed materials must also include the following notice: ''This document does not necessarily reflect the views or policies of the U.S. Department of Labor, nor does mention of trade names, commercial products, or organizations imply endorsement by the U.S. Government.''

Public reference to grant: When issuing statements, press releases, requests for proposals, bid solicitations, and other documents describing projects or programs funded in whole or in part with Federal money, all grantees receiving Federal funds must clearly state:

- The percentage of the total costs of the program or project, which will be financed with Federal money;
- The dollar amount of Federal financial assistance for the project or program; and
- The percentage and dollar amount of the total costs of the project or program that will be financed by non-governmental sources.

*Use of DOL and ODEP Logo:* In consultation with DOL/ODEP, the Grantee must acknowledge DOL's role as described. The DOL and/or ODEP logo may be applied to DOL-funded material prepared for world-wide distribution, including posters, videos, pamphlets, research documents, national survey results, impact evaluations, best practice reports, and other publications of global interest. The Grantee must consult with ODEP on whether the logo may be used on any such items prior to final draft or final preparation for distribution. In no event shall the DOL and/or ODEP logo be placed on any item until ODEP has given the grantee written permission to use the logo on the item.

All documents must include the following notice: ''This document does not necessarily reflect the views or policies of the U.S. Department of Labor, nor does mention of trade names, commercial products, or organizations imply endorsement by the U.S. Government.''

d. Intellectual Property

Please be advised that DOL/ODEP will reserve a royalty-free, nonexclusive, and irrevocable license to reproduce, publish, distribute, publicly display and perform, create derivative works from, and to authorize others to use, for Federal Government purposes:

(a) Any work developed under a grant, subgrant, or contract under a grant or subgrant; and

(b) Any rights to which a grantee, subgrantee or a contractor purchases ownership with grant support.

In addition, the Grantee will agree to notify DOL/ODEP of any pre-existing copyrighted materials it intends to incorporate into materials developed under the grant, and, prior to such incorporation, the grantee will agree that it will acquire, on behalf of DOL/ODEP, any necessary licenses to allow DOL/ODEP to exercise the rights described in the paragraph above.

e. Approval of Key Personnel and Subcontractors

The recipient shall notify the Grant Officer (through the Grant Officer Technical Representative) at least 14 calendar days in advance if any key personnel are to be removed or diverted from the cooperative agreement, shall supply written justification as part of this notice as to why these persons are to be removed or diverted, shall provide the names(s) of the proposed substitute or replacement, and shall include information on each new individual's qualifications such as education and work experience.

f. Paperwork Reduction Act Information

OMB Information Collection No. 1205–0458, Expires September 30, 2009. According to the Paperwork Reduction Act of 1995, no persons are required to respond to a collection of information unless such collection displays a valid OMB control number. Public reporting burden for this collection of information is estimated to average 20 hours per response, including time for reviewing instructions, searching existing date sources, gathering and maintaining data needed, and completing and reviewing the collection of information. Send comments regarding the burden estimated or any other aspect of this collection of information, including suggestions for reducing this burden, to the U.S. Department of Labor, to the attention of Cassandra Mitchell, 200 Constitution Avenue, NW., Room S–4307, Washington, DC 20210.

This information is being collected for the purpose of awarding a grant. The information collected through this ''Solicitation for Grant Applications'' will be used by the Department of Labor to ensure that grants are awarded to the applicant best suited to perform the functions of the grant. Submission of this information is required in order for the applicant to be considered for award of this grant. Unless otherwise specifically noted in this announcement, information submitted in the respondent's applicant is not considered to be confidential.

## VII. Reporting and Monitoring

ODEP is responsible for ensuring effective implementation of this Cooperative Agreement, in accordance with the provisions of this announcement and the terms of the Cooperative Agreement award document. Applicants should assume that ODEP staff will conduct on-site project reviews periodically. Reviews will focus on timely project implementation, performance in meeting the Cooperative Agreement's objectives, tasks and responsibilities, expenditures of Cooperative Agreement funds on allowable activities, and administration of project activities. Projects may be subject to other additional reviews, at the discretion of ODEP.

The selected applicant must submit on a quarterly basis, beginning ninety (90) days from the award of the grant, financial and activity reports under this program as prescribed by OMB Circular A–110, codified at 2 CFR part 215 and 29 CFR part 95. Specifically the following reports will be required:

1. *Quarterly report:* The quarterly report is estimated to take five (5) hours to complete. The form for the quarterly report will be provided by ODEP. The Department will work with the Grantee to help refine the requirements of the report, which, among other things, will include measures of ongoing analysis for continuous improvement. This report will be filed using a system specified by ODEP. The form will be submitted within thirty (30) days of the close of the quarter. The quarterly progress report will include narrative description and will provide:

a. In-depth information on accomplishments, including project success stories, upcoming activities and promising approaches and processes;

b. Progress toward performance outcomes, including updates on products, activities and emerging promising practices in areas targeted by this Cooperative Agreement.

In addition, the selected applicant must submit every 6 months an Executive Summary report of project activities and outcomes to date. The report must detail the various aspects of project activities and accomplishments in a form and format provided by the Department.

2. *Standard Form 269, Financial Status Report Form:* This form is to be completed and submitted on a quarterly basis using the Department of Labor's E-Grants Reporting System unless ODEP provides different instructions.

3. *Final Project Report:* The Final Project Report is to include an assessment of project performance and outcomes achieved. It is estimated that this report will take twenty (20) hours to complete. This report will be submitted in hard copy and on electronic disk using a format and following instructions, to be provided by ODEP. A draft of the final report is due to ODEP sixty (60) days before the end of the period of performance of the cooperative agreement. The final report is due to ODEP and the DOL Grants Office ten (10) days before the end of the period of performance of the Cooperative Agreement.

The Department will arrange for an evaluation of the outcomes, impacts, accomplishments, and benefits of each funded project. The Grantee must agree to cooperate with this evaluation and must make available records on all parts of project activity, including available data on service-delivery models being studied and provide access to personnel, as specified by the evaluator(s), under the direction of ODEP. This evaluation is separate from the ongoing evaluation for continuous improvement required of the grantee for project implementation.

Technical assistance efforts will be coordinated with other technical assistance efforts implemented by ODEP, including, if applicable, the National Center on Workforce and Disability for Adults (NCWD/A) and the national Self-Employment Technical Assistance, Resources, and Training Center (START–UP USA). The grantee must also agree to work with ODEP in its various technical assistance efforts in order to freely share with others what is learned about building systems capacity and leadership across generic and disability-specific systems and linking asset development and employment activities. The Grantee must agree to collaborate with other research institutes, centers, studies, and evaluations that are supported by the DOL and other relevant Federal agencies, as appropriate. Finally, the Grantee must agree to actively utilize as appropriate the programs sponsored by the ODEP, including the Job Accommodation Network (*http://www.jan.wvu.edu*), and the Employer Assistance and Recruiting Network (*http://www.earnworks.com*).

The successful applicant will be required to prepare a strategic plan for achieving the goals of the Cooperative Agreement for the initial 24-month period of performance and submit it to ODEP for approval within 45 days of award for approval.

## VIII. Agency Contacts

Any questions regarding this SGA should be directed to Cassandra Mitchell, e-mail address: *mitchell.cassandra@dol.gov*, tel: 202–693–4570 (note that this is NOT a toll-free number). To obtain further information about the Office of Disability Employment Policy of the U.S. Department of Labor, visit the DOL Web site of the Office of Disability Employment Policy at *http://www.dol.gov/odep*.

## IX. Appendices

The appendices are as follows:

Appendix A. Application for Federal Assistance, Form SF–424.

Appendix B. Budget Information Sheet, Form SF–424A.

Appendix C. Assurances and Certifications Signature Page.

(Appendices D and E are not applicable).

Appendix F. Survey on Ensuring Equal Opportunity for Applicants.

Detailed information and document locations:

- Appendix A. Application for Federal Assistance, Form SF–424 (OMB No. 4040–0004).
- Appendix B. Budget Information Sheet, Form SF–424A (OMB No. 0348–0044). Both forms SF–424 and 424A can be obtained at the following Web address: *http://apply.grants.gov/agency/FormLinks?family=7*.
- Appendix F. Survey on Ensuring Equal Opportunity for Applicants (OMB No. 1890–0014).
- The Survey on Ensuring Equal Opportunity for Applicants form can be obtained at the following Web address: *http://www.ed.gov/fund/grant/apply/appforms/surveyeo.pdf*. (If this link is viewed in an electronic format and the user receives a ''page not found'' message, it is recommended that the user cut and paste the URL into his/her browser window.)

## Appendix C. Assurances and Certifications Signature Page

### Certifications and Assurances

*Assurances and Certifications Signature Page*

The Department of Labor will not award a grant or agreement where the grantee/recipient has failed to accept the assurances and certifications contained in this section. By signing and returning this signature page, the grantee/recipient is providing the certifications set forth below:

A. Certification Regarding Lobbying, Debarment, Suspension, Other Responsibility Matters—Primary Covered Transactions and Certifications Regarding Drug-Free/Tobacco-Free Workplace.

B. Certification of Release of Information.

C. Assurances—Non-Construction Programs.

D. Applicant is not a 501(c)(4) organization.

Applicant Name and Legal Address:

If there is any reason why one of the assurances or certifications listed cannot be signed, the applicant shall provide an explanation. Applicant need only submit and return this signature page with the grant application. All other instruction shall be kept on file by the applicant.

Signature of Authorized Certifying Official

Title

Applicant Organization

Date Submitted

**Please Note:** This signature page and any pertinent attachments which may be required by these assurances and certifications shall be attached to the applicant's cost proposal.

Signed at Washington, DC, this 17th day of July, 2007.

**Cassandra Mitchell,**

*Grant Officer.*

[FR Doc. E7–14074 Filed 7–19–07; 8:45 am]

BILLING CODE 4510–FK–P

**DEPARTMENT OF LABOR**

**Employment Standards Administration**

**Proposed Collection; Comment Request**

**ACTION:** Notice.

**SUMMARY:** The Department of Labor, as part of its continuing effort to reduce paperwork and respondent burden, conducts a preclearance 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 Employment Standards Administration is soliciting comments concerning the proposed extension of the information collection requirements of the collection: Office of Federal Contract Compliance Programs Complaint Form (CC–4). 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 September 18, 2007.

**ADDRESSES:** Ms. Hazel M. Bell, U.S. Department of Labor, 200 Constitution Ave., NW., Room S–3201, Washington, DC 20210, telephone (202) 693–0418, fax (202) 693–1451, e-mail *bell.hazel@dol.gov.* Please use only one method of transmission for comments (mail, fax, or e-mail).

**SUPPLEMENTARY INFORMATION:**

## I. Background

This information collection request covers the recordkeeping and reporting requirements for the Office of Federal Contract Compliance Programs (OFCCP) Complaint Form CC–4, Complaint of Discrimination in Employment under Federal Government Contracts. This information collection is currently approved for use through January 31, 2008.

The OFCCP is responsible for the administration of three equal opportunity programs prohibiting employment discrimination and requiring affirmative action on the basis of race, color, sex, religion, national origin, or status as a qualified individual with a disability or protected veteran: Executive Order 11246, as amended (Executive Order); Section 503 of the Rehabilitation Act of 1973, as amended (Section 503); and the affirmative action provisions of the Vietnam Era Veterans' Readjustment Assistance Act of 1974, as amended (VEVRAA). The regulations implementing the Executive Order program are found at 41 CFR Parts 60–1, 60–2, 60–3, 60–4, 60–20, 60–30, 60–40, and 60–50. The regulations implementing Section 503 are published at 41 CFR part 60–741. The regulations implementing VEVRAA are found at 41 CFR part 60–250.

All three programs give employees and applicants for employment with Federal contractors the right to file a complaint of discrimination. It is well established, however, that no private right of action exists under the three programs. The exclusive remedy for complaints is the administrative procedures of the U.S. Department of Labor. These procedures are initiated by filing a written complaint, using the Complaint Form CC–4, Complaint of Discrimination in Employment under Federal Government Contracts. The Form CC–4 is used to file a complaint under all three laws enforced by OFCCP.

Under the Executive Order, the authority for collection of complaint information is Section 206(b). The implementing regulations which specify the content of this information collection are found at 41 CFR 60–1.23(a). Section 503 provides the authority for collecting complaint information at 41 CFR 60–741.61. The implementing regulations which specify the content of this information collection are found at 41 CFR 60–741.61(c).

Under VEVRAA, the authority for collecting complaints information is at 38 U.S.C. 4212(d). The implementing regulations which specify the content of this information collection are found at 41 CFR 60–250.61(b). The Jobs for Veterans Act (JVA) enacted in 2002 changed the categories of veterans protected under VEVRAA and consequently the categories of veterans eligible to file a complaint of discrimination. The Form CC–4 has been revised to reflect the changes required by JVA.

## 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 the approval of the extension of this information in order to carry out its responsibility to enforce the affirmative action and anti-discrimination provisions of the three Acts, which it administers.

*Type of Review:* Extension.

*Agency:* Employment Standards Administration.

*Title:* Office of Federal Contract Compliance Programs Complaint Form.

*OMB Number:* 1215–0131.

*Agency Number:* CC–4.

*Affected Public:* Individuals or households.

*Total Respondents:* 594.

*Total Annual Responses:* 594.

*Average Time per Response:* 1.28 hours.

*Estimated Total Burden Hours:* 760.

*Frequency:* On occasion.

*Total Burden Cost (capital/startup):* $0.

*Total Burden Cost (operating/maintenance):* 261.36

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: July 16, 2007.

**Hazel Bell,**

*Acting Chief, Branch of Management Review and Internal Control, Division of Financial Management, Office of Management, Administration and Planning, Employment Standards Administration.*

[FR Doc. E7–14039 Filed 7–19–07; 8:45 am]

**BILLING CODE 4510–CM–P**

## DEPARTMENT OF LABOR

### Employment Standards Administration

### Proposed Collection; Comment Request

**ACTION:** Notice.

**SUMMARY:** The Department of Labor, as part of its continuing effort to reduce paperwork and respondent burden, conducts a preclearance 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 Employment Standards Administration is soliciting comments concerning the proposed collection: Report of Construction Contractor's Wage Rates (WD–10). 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 September 18, 2007.

**ADDRESSES:** Ms. Hazel M. Bell, U.S. Department of Labor, 200 Constitution Ave., NW., Room S–3201, Washington, DC 20210, telephone (202) 693–0418, fax (202) 693–1451, e-mail *bell.hazel@dol.gov*. Please use only one method of transmission for comments (mail, fax, or e-mail).

**SUPPLEMENTARY INFORMATION:**

### I. Background

The Davis-Bacon Act (40 U.S.C. 3141, *et seq.*) provides, in part, that every contract in excess of $2,000 to which the United States or the District of Columbia is a party for construction, alteration, and/or repair, which requires or involves the employment of mechanics and/or laborers, shall contain a provision stating the minimum wages to be paid various classes of laborers and mechanics that were determined by the Secretary of Labor to be prevailing for the corresponding classes of laborers and mechanics employed on projects of a character similar to the contract work in the city, town, village or other civil subdivision of the State where the work is to be performed. The Administrator of the Wage and Hour Division, through a delegation of authority, is responsible for issuing these wage determinations (WDs). Section 1.3 of Regulations 29 CFR Part 1, Procedures for Predetermination of Wage Rates, provides, in part, that for the purpose of making WDs, the Administrator will conduct a continuing program for obtaining and compiling wage rate information. Form WD–10 is used to determine locally prevailing wages under the Davis-Bacon and Related Acts. The wage data collection is a primary source of information and is essential to the determination of prevailing wages. This information collection is currently approved for use through January 31, 2008.

### 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 Wage and Hour Division seeks the approval of the extension of this information collection to obtain wage data in order to determine current prevailing wage rates in the various localities throughout the country.

*Type of Review:* Extension.

*Agency:* Employment Standards Administration.

*Title:* Report of Construction Contractor's Wage Rates.

*OMB Number:* 1215–0046.

*Agency Number:* WD–10.

*Affected Public:* Business or other for-profit.

*Total Respondents:* 22,000.

*Total Annual Responses:* 66,000.

*Time per Response:* 20 minutes.

*Estimated Total Burden Hours:* 22,000.

*Frequency:* On occasion.

*Total Burden Cost (capital/startup):* $0.

*Total Burden Cost (operating/maintenance):* $0.

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: July 16, 2007.

**Hazel Bell,**

*Acting Chief, Branch of Management Review and Internal Control, Division of Financial Management, Office of Management, Administration and Planning, Employment Standards Administration.*

[FR Doc. E7–14040 Filed 7–19–07; 8:45 am]

BILLING CODE 4510–27–P

## DEPARTMENT OF LABOR

### Employment Standards Administration

### Proposed Collection; Comment Request

**ACTION:** Notice.

**SUMMARY:** The Department of Labor (DOL), as part of its continuing effort to reduce paperwork and respondent burden, conducts a preclearance 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 Employment Standards Administration is soliciting comments concerning the proposed collection: Applications to Employ Special Industrial Homeworkers and Workers with Disabilities (Forms WH–2, WH–226 and WH–226A). 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 September 18, 2007.

**ADDRESSES:** Ms. Hazel M. Bell, U.S. Department of Labor, 200 Constitution Ave., NW., Room S–3201, Washington, DC 20210, telephone (202) 693–0418, fax (202) 693–1451, e-mail *bell.hazel@dol.gov*. Please use only one method of transmission for comments (mail, fax, or e-mail).

**SUPPLEMENTARY INFORMATION:**

## I. Background

Fair Labor Standards Act (FLSA) section 11(d), 29 U.S.C. 211(d), authorizes the Secretary of Labor to regulate, restrict or prohibit industrial homework as necessary to prevent circumvention or evasion of the minimum wage requirement of the Act. The Department of Labor (DOL) restricts homework in seven industries (i.e., knitted outerwear, women's apparel, jewelry manufacturing, gloves and mittens, button and buckle manufacturing, handkerchief manufacturing and embroideries) to those employers who obtain certificates.

To prevent curtailment of employment opportunities for workers with disabilities, FLSA section 14(c), 29 U.S.C. 214(c), authorizes employers who obtain a certificate from DOL to pay special minimum wages (i.e., wages less than the Federal minimum wage) to workers whose productivity is impaired by their disability. The FLSA defines a ''worker with a disability'' as an individual whose earning or productive capacity is impaired by age or physical or mental disability.

Employers use Form WH–2 to obtain certificates to employ individual homeworkers in one of the restricted homework industries. Upon application by the homeworker and the employer, DOL may issue a certificate to the employer authorizing employment of an individual homeworker, provided (1) it is shown that the worker is unable to adjust to factory work because of age or physical or mental disability or is unable to leave home because the worker's presence is required to care for an invalid in the home, and (2) the worker has been engaged in industrial homework in the particular industry prior to certain specified dates as set forth in the regulations (may be waived if causes unusual hardship) or is engaged in industrial homework under the supervision of a State Vocational Rehabilitation Agency.

Employers use Form WH–226 and the supplemental data Form WH–226A when obtaining authorization to employ workers with disabilities in competitive employment in work centers and in hospitals or institutions at subminimum wages that are commensurate with those paid to workers with no disabilities. Commensurate wages are based on the prevailing wages paid to experienced workers with disabilities performing essentially the same type, quality, and quantity of work in the same locality where the employee(s) with disability is employed. This form may be used by school officials to request authorization for groups of students with disabilities to participate in school work experience programs, by State vocational rehabilitation counselors, and by Veterans Affairs' officials to grant or extend temporary authorization to employ on-the-job trainees with disabilities.

This information collection is currently approved for use through December 31, 2007.

## 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

DOL seeks approval for the extension of this information collection in order to ensure effective administration of agency programs regarding the employment of homeworkers in restricted industries and payment of subminimum wages to workers with disabilities.

*Type of Review:* Extension.

*Agency:* Employment Standards Administration.

*Title:* Applications to Employ Special Industrial Homeworkers and Workers with Disabilities.

*OMB Number:* 1215–0005.

*Agency Number:* WH–2, WH–226, WH–226A.

*Affected Public:* Business or other for-profit.

*Total Respondents:* 3,050.

*Total Responses:* 12,050.

| Form | Number of respondents | Number of responses | Time per response (in minutes) | Burden hours |
|---|---|---|---|---|
| WH–2 | 50 | 50 | 30 | 25 |
| WH–226 | 3,000 | 3,000 | 45 | 2,250 |
| WH–226A | 3,000 | 9,000 | 45 | 6,750 |

*Frequency:* Annually.

*Estimated Total Burden Hours:* 9,025.

*Total Burden Cost (capital/startup):* $0.

*Total Burden Cost (operating/maintenance):* $1,342.

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: July 16, 2007.

**Hazel Bell,**

*Acting Chief, Branch of Management Review and Internal Control, Division of Financial Management, Office of Management, Administration and Planning, Employment Standards Administration.*

[FR Doc. E7–14041 Filed 7–19–07; 8:45 am]

BILLING CODE 4510–27–P

## DEPARTMENT OF LABOR

## Occupational Safety and Health Administration

## OSHA Training Institute Education Center; Notice of Competition and Request for Applications

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

**ACTION:** Notice of competition and request for applications for the OSHA

Training Institute Education Center Program.

**SUMMARY:** The Occupational Safety and Health Administration (OSHA) conducts short-term technical training in occupational safety and health topics through the OSHA Training Institute in Arlington Heights, Illinois. The number of requests for training from private sector personnel and federal personnel from agencies other than OSHA increased beyond the capacity of the OSHA Training Institute to meet the demand. In October 1992, OSHA began the program of using other training and educational institutions to conduct select OSHA Training Institute courses for private sector personnel and for federal personnel from agencies other than OSHA. Additional information regarding the OTI Education Center Program background, including a complete list of current organizations and course offerings, can be found on the OSHA Web site at: *http://www.osha.gov/fso/ote/training/edcenters/index.html.*

This notice announces the opportunity for interested nonprofit organizations to submit applications to become an OSHA Training Institute Education Center. Applications will be rated on a competitive basis. Complete application instructions are contained in this notice. This notice also contains information on a proposal conference designed to provide potential applicants with information about the OSHA Training Institute Education Center Program.

**DATES:** Applications (3 copies) must be received by 4:30 p.m. central time on Friday, August 24, 2007. The proposal conference date is Tuesday, August 7, 2007, from 1 p.m. to 3 p.m. central time, at the OSHA Directorate of Training and Education, 2020 S. Arlington Heights Rd., Arlington Heights, Illinois 60005–4102.

**ADDRESSES:** Submit applications (3 copies) to the U.S. Department of Labor, Occupational Safety and Health Administration, Directorate of Training and Education, Office of Training and Educational Programs, 2020 S. Arlington Heights Rd., Arlington Heights, Illinois 60005–4102.

**FOR FURTHER INFORMATION CONTACT:** Neil Elbrecht, Program Analyst, or Jim Barnes, Director, Office of Training and Educational Programs, OSHA Directorate of Training and Education, 2020 S. Arlington Heights Rd., Arlington Heights, Illinois 60005–4102, telephone (847) 297–4810.

**SUPPLEMENTARY INFORMATION:**

## OSHA Training Institute (OTI)

The OSHA Training Institute in Arlington Heights, Illinois, is the primary training provider of the Occupational Safety and Health Administration. It conducts more than 100 short-term courses and seminars covering OSHA standards, policies, and procedures for persons responsible for enforcing or directly supporting the Occupational Safety and Health Act, for private sector employers and employees, and federal personnel from agencies other than OSHA. The OSHA Training Institute's primary responsibility is to federal and state compliance officers and state consultation program staff. Private sector personnel and federal personnel from agencies other than OSHA receive training from the OSHA Training Institute on a space available basis.

## OTI Education Center Program Origin

By the early 1990s, requests for training from federal and state compliance officers, state consultation program staff, private sector personnel, and federal personnel from agencies other than OSHA had increased beyond the capacity of the OSHA Training Institute to meet the demand. In addition, resources of the OSHA Training Institute had not increased at a rate that could keep up with the demand. As the number of students from federal and state personnel engaged in enforcement or consultation increased, opportunities for training for private sector personnel and federal personnel from agencies other than OSHA remained static or decreased. In order to meet the increased demand for its courses, the OSHA Training Institute selected nonprofit organizations to conduct select OSHA Training Institute courses for private sector personnel and federal personnel from agencies other than OSHA. Current organizations were selected through regional competitions.

## Current OTI Education Centers

The current OSHA Training Institute Education Centers are: Keene State College, Manchester, New Hampshire; Rochester Institute of Technology, Rochester, New York; University of Medicine & Dentistry of New Jersey, Piscataway, New Jersey/State University of New York, Buffalo, New York/Universidad Metropolitana, Bayamón Puerto Rico; Building and Construction Trades Department AFL–CIO/Center to Protect Workers' Rights, Washington, DC/National Labor College, Silver Spring, Maryland/West Virginia University, Morgantown, West Virginia; Indiana University of Pennsylvania, Indiana, Pennsylvania; Georgia Technical Research Institute, Atlanta, Georgia; Eastern Kentucky University, Richmond, Kentucky; University of South Florida, Tampa, Florida; Eastern Michigan University, Ypsilanti, Michigan/United Auto Workers, Detroit, Michigan/University of Cincinnati, Cincinnati, Ohio; Northern Illinois University, DeKalb, Illinois/Construction Safety Council, Hillside, Illinois/National Safety Council, Itasca, Illinois; Ohio Valley Construction Education Foundation, Springboro, Ohio/Sinclair Community College, Dayton, Ohio; Texas Engineering Extension Service, Texas A&M University System, Mesquite, Texas; Metropolitan Community Colleges, Business & Technology Center, Kansas City, Missouri; Kirkwood Community College, Kirkwood, Iowa/Saint Louis University, Saint Louis, Missouri/National Safety Council of Greater Omaha, Omaha, Nebraska; University of Utah/Salt Lake Community College, Salt Lake City, Utah; Red Rocks Community College, Lakewood, Colorado; University of California, San Diego, San Diego, California; Westside Energy Services, Taft, California; and the University of Washington, Seattle, Washington.

## OTI Education Center Selection Guidelines

OSHA does not have a predetermined number of organizations to be selected to act as OSHA Training Institute Education Centers. Rather, the number of organizations selected will be determined according to the qualifications of the applicants and their ability to serve the regional populations. Colleges, universities, or other nonprofit training organizations will be selected based upon their ability to conduct OSHA courses for private sector personnel and federal personnel from agencies other than OSHA.

## Geographic Distribution

OSHA Training Institute Education Centers are currently in each OSHA Region. However, OSHA may elect to select more than one OSHA Training Institute Education Center in some OSHA Regions. The Regions contain the following states.

1. Region I: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont.
2. Region II: New Jersey, New York, Puerto Rico, and Virgin Islands.
3. Region III: Delaware, District of Columbia, Maryland, Pennsylvania, Virginia, and West Virginia.
4. Region IV: Alabama, Florida, Georgia, Kentucky, Mississippi, North

Carolina, South Carolina, and Tennessee.

5. Region V: Illinois, Indiana, Michigan, Minnesota, Ohio, and Wisconsin.

6. Region VI: Arkansas, Louisiana, New Mexico, Oklahoma, and Texas.

7. Region VII: Iowa, Kansas, Missouri, and Nebraska.

8. Region VIII: Colorado, Montana, North Dakota, South Dakota, Utah, and Wyoming.

9. Region IX: American Samoa, Arizona, California, Guam, Hawaii, Nevada, and Trust Territories of the Pacific.

10. Region X: Alaska, Idaho, Oregon, and Washington.

For this notice of competition, special emphasis will be given to the following major metropolitan locations:

Austin, TX
Baltimore, MD
Birmingham, AL
Charlotte, NC
Cleveland, OH
Columbus, OH
Hartford, CT
Houston, TX
Indianapolis, IN
Jacksonville, FL
Kansas City, MO
Las Vegas, NV
Los Angeles-Long Beach-Santa Ana, CA
Louisville, KY
Memphis, TN
Miami-Fort Lauderdale, FL
Milwaukee, WI
Minneapolis-St. Paul-Bloomington, MN
Nashville, TN
New Orleans, LA
New York, NY
Northern New Jersey
Oklahoma City, OK
Orlando, FL
Philadelphia, PA
Phoenix-Mesa-Scottsdale, AZ
Pittsburgh, PA
Portland, OR
Providence, RI
Richmond, VA
Riverside-San Bernardino-Ontario, CA
Sacramento, CA
San Antonio, TX
San Francisco-Oakland-Fremont, CA
San Jose-Sunnyvale-Santa Clara, CA
Virginia Beach-Norfolk-Newport News, VA
Wilmington, DE

**OTI Courses Required To Be Presented**

OSHA Training Institute Education Centers are required to present the following six courses on an annual basis:

#500 Trainer Course in Occupational Safety and Health Standards for the Construction Industry
#501 Trainer Course in Occupational Safety and Health Standards for General Industry
#502 Update for Construction Industry Outreach Trainers
#503 Update for General Industry Outreach Trainers
#510 Occupational Safety and Health Standards for the Construction Industry
#511 Occupational Safety and Health Standards for General Industry

In addition, OTI Education Centers are required to present at least five of the following courses on an annual basis:

#521 OSHA Guide to Industrial Hygiene
#2015 Hazardous Materials
#2045 Machinery and Machine Guarding Standards
#2225 Respiratory Protection
#2250 Principles of Ergonomics Applied to Work-Related Musculoskeletal and Nerve Disorders
#2264 Permit-Required Confined Space Entry
#3010 Excavation, Trenching and Soil Mechanics
#3095 Electrical Standards
#3110 Fall Arrest Systems
#5600 Disaster Site Worker Train-the-Trainer Course
#6000 Collateral Duty Course for Other Federal Agencies

In addition, OTI Education Centers will be allowed, but not required, to present any of the following short courses and seminars:

#7000 OSHA Ergonomic Guidelines for Nursing Homes
#7005 Public Warehousing and Storage
#7100 Introduction to Machinery and Machine Safeguarding
#7105 Evacuation and Emergency Planning
#7200 Bloodborne Pathogen Exposure Control for Healthcare Facilities
#7205 Health Hazard Awareness
#7300 OSHA's Permit-Required Confined Space Standard
#7400 Trainer Course in Construction Noise
#7405 Fall Hazard Awareness for the Construction Industry
#7500 Introduction to Safety and Health Management
#7505 Introduction to Accident Investigation
#7510 Introduction to OSHA for Small Business
#7845 Recordkeeping Rule Seminar

A brief description of each of the courses is attached.

OSHA may increase or decrease the number of different courses available to be offered by the OSHA Training Institute Education Centers.

**Selection Criteria**

Applicants will be selected based upon their occupational safety and health training experience, their nonacademic training background, the availability of classrooms, laboratories, and conference facilities, access to transportation and lodging at their resident location, and their capability to provide training throughout their Region.

**Application Eligibility**

Any nonprofit public or private college or university is eligible to apply. Any other nonprofit organization that can demonstrate that training or education is part of its mission and that more than 50 percent of its staff and dollar resources is devoted to training or education is also eligible.

**Funding Provisions**

OSHA provides no funding to the OSHA Training Institute Education Centers. The OSHA Training Institute Education Centers will be expected to support their OSHA training through their normal tuition and fee structures.

**Cooperative Agreement Duration**

Selected applicants will sign non-financial cooperative agreements with OSHA effective October 1, 2007 through September 30, 2012. With satisfactory performance, agreements may be renewed without competition for an additional five years.

**Geographic Criteria**

Applicants must have a physical presence in the OSHA Region for which they are applying. For example, an eligible national organization based in San Francisco that has a training facility in Chicago would have a physical presence in Region V. On the other hand, a national organization based in New York City that rents hotel space to provide training at multiple sites around the country would be considered to have a physical presence only in Region II. OSHA Training Institute Education Centers are expected to provide training throughout their respective Regions. In addition, applicants must demonstrate the capability to locate satellite downlink sites for use by federal and state employees and private sector employers and employees to receive satellite delivered training from the OSHA Training Institute. At a minimum, applicants should identify potential satellite downlink sites in all cities with a federal or state compliance office or state consultation office as well as other major population centers within their Region.

**Consortia and Partnerships**

Applicants may join with one or more other nonprofit organizations in their Region to apply as a consortium. A training or education institution may elect to apply for this program in partnership with a safety and health organization that is not primarily a training organization. For example, a university could enter into an agreement with a labor union that provides for the use of university classrooms and faculty supplemented by union safety and health professionals. All consortium partners must be physically located in the same OSHA region.

**OTI Education Center Responsibilities**

OSHA Training Institute Education Centers are responsible for the following:

1. Ensure that instructors are qualified in the courses/subjects they will be teaching.
2. Arrange for course chairpersons to attend OSHA orientation for each OSHA Training Institute course for which they are the chair.
3. Schedule courses on a year-round basis with each required course being offered at least once a year.
4. Schedule courses at various locations throughout their respective Region.
5. Publicize and promote the availability of courses to ensure attendance and the delivery of the scheduled courses.
6. Conduct at least five courses per month and achieve annual student training goals and objectives as established by OSHA.
7. Facilitate student registration.
8. Acquire audiovisual materials for use in the courses.
9. Reproduce handouts for students.
10. Conduct courses in accordance with materials and instructions provided by OSHA.
11. Monitor courses to ensure that OSHA course outlines are being followed and OSHA learning objectives are being met.
12. Collect course evaluation data from students in accordance with OSHA procedures and provide that data to OSHA.
13. Maintain student registration and attendance records in accordance with OSHA guidelines.
14. Issue course completion certificates to students. These certificates, which certify that a student has completed training in a particular course, must be approved by OSHA.
15. Provide the OSHA Directorate of Training and Education with summary reports indicating number of courses delivered, locations of courses, and number of students.
16. Maintain clearly identifiable records of tuition and fees collected from OSHA course students.
17. Identify the availability of appropriate accommodations for students.
18. Administer Outreach Training Program activities. This includes distribution of student cards to active Outreach Training Program trainers and providing trainer and student information to the OSHA Directorate of Training and Education on a regular basis.

**Outreach Training Program**

The Outreach Training Program is a voluntary program through which OSHA authorizes trainers to conduct 10- and 30-hour training courses on occupational safety and health hazards. Persons who successfully complete either OSHA Training Institute course #500 Trainer Course in Occupational Safety and Health Standards for the Construction Industry or #501 Trainer Course in Occupational Safety and Health Standards for General Industry are authorized to conduct 10- and 30-hour training courses, to submit training documentation to the appropriate organization, and issue OSHA course completion cards to their students. Construction outreach trainers must attend #502 Update for Construction Industry Outreach Trainers once every four years to maintain their active status, while general industry outreach trainers must attend #503 Update for General Industry Outreach Trainers once every four years to maintain their active status.

**OSHA Training Institute Responsibilities**

The OSHA Training Institute is responsible for the following:

1. Provide OSHA Training Institute Education Center course chairpersons with orientation on how the OSHA Training Institute teaches the course.
2. Provide course objectives for each OSHA course to be presented by the OSHA Training Institute Education Center.
3. Provide answers and technical assistance on questions of OSHA policy.
4. Monitor the performance of the OSHA Training Institute Education Center through on-site visits including unannounced attendance at courses and examination of course reports and attendance records.
5. Evaluate the effectiveness of the OSHA Training Institute Education Center and provide each organization with an annual performance appraisal.

**Proposal Conference**

The proposal conference is intended to provide potential applicants with information about the OSHA Training Institute, OSHA Training Institute courses and methods of instruction, and administrative and program requirements for a OSHA Training Institute Education Center. The OSHA Directorate of Training and Education will hold one proposal conference.

The proposal conference is scheduled for Tuesday, August 7, 2007 from 1 p.m. to 3 p.m. central time, at the OSHA Directorate of Training and Education, 2020 S. Arlington Heights Rd., Arlington Heights, Illinois 60005–4102.

Applicants interested in attending this conference may contact Neil Elbrecht, Program Analyst, or Jim Barnes, Director, Office of Training and Educational Programs, OSHA Directorate of Training and Education, 2020 S. Arlington Heights Rd., Arlington Heights, Illinois 60005–4102, telephone (847) 297–4810, for information about local accommodations and transportation. It is not necessary to register for the conference.

**Application Requirements**

Applicants must address each of the following points in their application.

1. Identifying Information. Provide the name and address of their organization. If the mailing address is a post office box, also provide the street address. Provide the name, title, and telephone number of the contact person who can answer questions about the application.
2. Authority to Apply. Provide a copy of the resolution by the Board of Directors, Board of Regents, or other governing body of their organization approving the submittal of an application to OSHA to become an OSHA Training Institute Education Center.
3. Nonprofit Status. Include evidence of the nonprofit status of their organization and of each member organization if they are applying as a consortium. A letter from the Internal Revenue Service or a statement included in a recent audit report is preferred. In the absence of either of these, a copy of the articles of incorporation showing the nonprofit status will be accepted.
4. Status as a Training Organization. This section applies only to applicants that are not colleges or universities. Show that training or education is a principal activity of their organization. Through audit reports, annual reports, or other documentation, demonstrate

that for the last two years more than 50 percent of the organization's funds have been used for training and education activities and that more than 50 percent of its staff resources have also been used for this purpose.

5. Occupational Safety and Health Training Experience. Describe the organization's relevant course offerings for the last two years. Include copies of catalogs and other recruitment materials that provide descriptive material about the courses. For each course, include the dates the course was offered and the number of students who completed the course. Also provide descriptive material including course descriptions and number of hours that is similar to the information contained in the appendix to this Notice.

6. OSHA Training Institute Courses. Indicate which of the OSHA Training Institute courses the organization would offer. The complete list of available courses is attached.

7. Staff Qualifications. Describe the qualifications of course chairpersons and staff teaching occupational safety and health courses. Indicate the professional qualifications of each, such as Certified Safety Professional (CSP), Professional Engineer (PE), or Certified Industrial Hygienist (CIH). Also describe staff knowledge of and experience with OSHA standards and their application to hazards and hazard abatement. Include resumes of current staff and position descriptions and minimum hiring qualifications for all positions, whether filled or vacant, that may be assigned to conduct OSHA classes.

8. Classroom Facilities. Describe classroom facilities available for presentation of the courses. Include number of students accommodated, table arrangements, and availability of audiovisual equipment. Also describe appropriate laboratory facilities and other facilities available for hands-on exercises. Indicate provisions for accessibility for persons with disabilities.

9. Distance Learning. Describe plans for identifying satellite downlink sites within the Region for receiving OSHA Training Institute broadcasts. Identify the types of organizations that would be contacted and the information that would be made available to the OSHA Training Institute to ensure a successful broadcast.

10. Outreach Training Program. Provide a description of the systems that would be in place to administer the Outreach Training Program and to assure its integrity including maintaining records, ensuring that only authorized trainers receive student cards, reviewing requests for student cards, and distributing student cards.

11. Tuition. Provide a copy of the organization's tuition and fee schedule. Explain how tuition or fees will be computed for each course, referencing the organization's tuition and fee schedule.

12. Recruitment. Explain procedures for marketing the training programs, promoting the organizations status as an OSHA Training Institute Education Center within the region, and recruiting students from the private sector and from federal agencies other than OSHA.

13. Registration. Describe registration procedures including provisions for cancellation, furnishing enrollees with hotel information, and tuition or fee collection.

14. Location. Describe the accessibility of the training facility for students. Include such items as distance from a major airport, number of airlines serving the airport, transportation from the airport to hotels, and distance from the interstate system.

15. Accommodations. Provide a representative listing of hotels available for student accommodation and give sample room rates. Explain how students will be transported between the hotels and classes. Describe the food service and restaurants available both in the area in which the classes will be held and in the area where the hotels are located.

16. Off-site Courses. Successful applicants are required to conduct courses at sites other than their own facilities, especially in other states in their Region. Describe the organization's plan to provide off-site training within their respective Region including procedures to assure that classroom facilities and accommodations are adequate.

17. Nondiscrimination. Provide copies of the organization's nondiscrimination policies covering staff and students. In the absence of a written policy, explain how the organization will ensure that staff and students are selected without regard to race, color, national origin, sex, age, or disability.

**Application Submission**

Applications (3 copies) must be submitted to the attention of Jim Barnes, Director, Office of Training and Educational Programs, OSHA Directorate of Training and Education, 2020 S. Arlington Heights Rd., Arlington Heights, Illinois 60005–4102. The submission is to consist of one original and two copies of the application. Applications should not be bound or stapled and should only be printed on one side of the page.

**Application Dealine**

Applications (3 copies) must be received no later than 4:30 p.m. central time on Friday, August 24, 2007.

**Application Review Process**

A panel of OSHA staff will review the application and will consider each of the factors listed below.

1. Occupational Safety and Health Training Experience. Evidence that occupational safety and health training or education has been an ongoing program of the organization. Reviewers will examine the number of different occupational safety and health courses offered by the organization, the number of students completing each course, and the number of times each course was offered.

2. Qualifications of Staff. For personnel teaching occupational safety and health courses this includes academic training in occupational safety and health subjects, experience with the application of OSHA standards to hazards and hazard abatement, professional certification, practical experience in the field of occupational safety and health, and experience in training workers or managers in nonacademic situations.

3. Outreach Training Program. Plans for administering the Outreach Training Program and ensuring program integrity will be reviewed.

4. Location. A major airport with regular service to all parts of the Region should be within a reasonable driving time from the training location and the hotel. Interstate highways should also be within reasonable distance.

5. Adequacy of Training Facilities. Potential for accommodating classes of 25 to 40 students on a year-round basis in settings comparable to those of the OSHA Training Institute will be reviewed. Items considered will include classroom layout, availability of audiovisual equipment, reproduction facilities for handouts, and availability of appropriate laboratory and hands-on facilities. Accessibility for persons with disabilities will also be considered.

6. Distance Learning. Successful applicants will demonstrate the capability to identify satellite downlink sites in their Region for use by federal and state employees and private sector employers and employees to receive satellite delivered training from the OSHA Training Institute. At a minimum, applicants should identify potential satellite downlink sites in all cities with a federal or state compliance office or state consultation office as well

as other major population centers within the Region.

7. Recruitment for the programs. Successful applicants will articulate their detailed plans for marketing the training programs, promoting status as an OSHA Training Institute Education Center within the region, and recruiting students from the private sector and from federal agencies other than OSHA.

8. Registration Procedures. How reasonable are the organization's procedures for registering students including methods of reaching potential students, ease of registration, provisions for cancellations, and system for informing students of available accommodations are among the items that will be reviewed.

9. Accommodations. Preferably, national hotel/motel chains and restaurants should be reasonably priced and should be within a few miles of the training facility.

10. Tuition. Conformance of proposed tuition or fees with the established policies of the applicant and reasonableness of the charges will be considered.

11. Off-site Courses. Experience and ability of the organization to conduct courses at sites other than its own facility will be considered.

12. Nondiscrimination. Adherence of the organization's policies with federal requirements will be reviewed.

**Application Selection Process**

The OSHA review panel will make recommendations to the Assistant Secretary of Labor for Occupational Safety and Health, who will make the final decisions.

**Notification of Selection**

Applicants will be notified by a representative of the Assistant Secretary of Labor for Occupational Safety and Health, if their organization is selected as an OSHA Training Institute Education Center. An organization may not conduct OSHA Training Institute Education Center activities until it has signed a non-financial cooperative agreement with OSHA.

**Notification of Non-Selection**

Applicants will be notified in writing if their organization is not selected to be an OSHA Training Institute Education Center.

**Non-Selection Appeal**

There is no appeal procedure for unsuccessful applicants. All decisions by the Assistant Secretary of Labor for Occupational Safety and Health are final.

Applicants may request a copy of the documentation of the review of their application by writing to Jim Barnes, Director, Office of Training and Educational Programs, OSHA Directorate of Training and Education, 2020 S. Arlington Heights Rd., Arlington Heights, Illinois 60005–4102.

**Authority**

Section 21 of the Occupational Safety and Health Act of 1970 (29 U.S.C. 670).

Signed at Washington, DC, this 16th day of July, 2007.

**Edwin G. Foulke, Jr.,**

*Assistant Secretary of Labor for Occupational Safety and Health.*

**Attachment**

*#500—Trainer Course in OSHA Standards for Construction*

This course is designed for personnel in the private sector interested in teaching the 10- and 30-hour construction safety and health outreach program to their employees and other interested groups. Special emphasis is placed on those topics that are required in the 10- and 30-hour programs as well as on those that are the most hazardous, using OSHA standards as a guide. Course participants are briefed on effective instructional approaches and the effective use of visual aids and handouts. This course allows the student to become a trainer in the Outreach Program and to conduct both a 10- and 30-hour construction safety and health course and to issue cards to participants verifying course completion. Prerequisites: Course #510 and five years of construction safety experience.

**Note:** Students in Course #500 who wish to participate as authorized trainers in the Outreach Program must successfully pass a written exam at the end of the course. Outreach trainers are required to attend Course #502 at least once every four years to maintain their trainer status.

*#501—Trainer Course in OSHA Standards for General Industry*

This course is designed for personnel in the private sector interested in teaching the 10- and 30-hour general industry safety and health outreach program to their employees and other interested groups. Special emphasis is placed on those topics that are required in the 10- and 30-hour programs as well as on those that are the most hazardous, using OSHA standards as a guide. Course participants are briefed on effective instructional approaches and the effective use of visual aids and handouts. This course allows the student to become a trainer in the Outreach Program and to conduct both a 10- and 30-hour general industry safety and health course and to issue cards to participants verifying course completion. Prerequisites: Course #511 and five years of general industry safety experience. **Note:** Students in Course #501 who wish to participate as authorized trainers in the Outreach Program must successfully pass a written exam at the end of the course. Outreach trainers are required to attend Course #503 at least once every four years to maintain their trainer status.

*#502—Update for Construction Industry Outreach Trainers*

This course is designed for personnel in the private sector who have completed #500 Trainer Course in Occupational Safety and Health Standards for the Construction Industry and who are active trainers in the outreach program. It provides an update on such topics as OSHA construction standards, policies, and regulations. Prerequisites: Course #500. **Note:** Outreach trainers are required to attend this course once every four years to maintain their trainer status. Students must bring their current trainer's card for validation.

*#503—Update for General Industry Outreach Trainers*

This course is designed for private sector personnel who have completed course #501 Trainer Course in Occupational Safety and Health Standards for General Industry and who are active trainers in the outreach program. It provides an update on OSHA general industry standards and OSHA policies. Prerequisites: Course #501.

**Note:** Outreach trainers are required to attend this course once every four years to maintain their trainer status. Students must bring their current trainer's card for validation.

*#510—Occupational Safety and Health Standards for Construction*

This course for private sector personnel covers OSHA policies, procedures, and standards, as well as construction safety and health principles. Topics include scope and application of the OSHA construction standards. Special emphasis is placed on those areas that are the most hazardous, using OSHA standards as a guide. Upon successful course completion, the student will receive an OSHA construction safety and health 30-hour course completion card.

*#511—Occupational Safety and Health Standards for General Industry*

This course for private sector personnel covers OSHA policies, procedures, and standards, as well as general industry safety and health principles. Topics include scope and application of the OSHA general industry standards. Special emphasis is placed on those areas that are the most hazardous, using OSHA standards as a guide. Upon successful course completion, the student will receive an OSHA general industry safety and health 30-hour course completion card.

*#521—OSHA Guide to Industrial Hygiene*

This course addresses industrial hygiene practices and related OSHA regulations and procedures. Topics include permissible exposure limits, OSHA health standards, respiratory protection, engineering controls, hazard communication, OSHA sampling procedures and strategy, workplace health program elements and other industrial hygiene topics. The course features workshops in health hazard recognition, OSHA health standards and a safety and health program workshop.

*#2015—Hazardous Materials*

This shortened version of #2010 covers OSHA general industry standards and integrates materials from other consensus and proprietary standards that relate to hazardous materials. Included are flammable and combustible liquids, compressed gases, LP-gases, and cryogenic liquids. Related processes such as spraying and dipping are covered, as well as electrical equipment. Prerequisites: 21(d) State Consultants: Computer-based #1500 Basic Onsite Consultation program. Other Federal Agency or Department Personnel: Course #2005, #6000, or #6010. Private Sector and Other Non-Federal Government personnel: Course #2005, #501, #510, or #511. This course is available to non-compliance personnel only.

*#2045—Machinery and Machine Guarding Standards*

This shortened version of #2040 familiarizes the student with various types of common machinery and the related safety standards. Guidance is provided on the hazards associated with various kinds of machinery and the control of hazardous energy sources (lockout/tagout). The course presents an approach to machinery inspection that enables participants to recognize hazards and to provide options to achieve abatement. These hazards include mechanical motions and actions created by points of operation and other machinery processes. Also included is hands-on training in the laboratories. Prerequisites: 21(d) State Consultants: Computer-based #1500 Basic Onsite Consultation program. Other Federal Agency or Department Personnel: Course #2005, #6000, or #6010. Private Sector and Other Non-Federal Government personnel: Course #2005, #501, #510 or #511. This course is available to non-compliance personnel only.

*#2225—Respiratory Protection*

This course covers the requirements for the establishment, maintenance, and monitoring of a respirator program. Topics include terminology, OSHA standards, National Institute for Occupational Safety and Health (NIOSH) certification, and medical evaluation recommendations. Program highlights include laboratories on respirator selection, qualitative fit testing, and the use of a large array of respiratory and support equipment for hands-on training.

*#2250—Ergonomics Applied to MSDs and Nerve Disorders*

This course covers the use of ergonomic principles to recognize, evaluate, and control work place conditions that cause or contribute to musculoskeletal and nerve disorders. Topics include work physiology, anthropometry, musculoskeletal disorders, use of video display terminals, and risk factors such as vibration, temperature, material handling, repetition, and lifting and transfers in health care. Course emphasis is on industrial case studies covering analysis and design of workstations and equipment, laboratory sessions in manual lifting, and coverage of current OSHA compliance policies. Prerequisites: OSHA Federal and State Compliance Officers: Course #1000. 21(d) State Consultants: Computer-based program, ''Basic Onsite Consultation.'' Safety personnel: Course #1210. Other Federal Agency or Department personnel: Course #6000, #6010 OR EQUIVALENT. Private Sector and Other Non-Federal Government personnel: Course #501, #510, OR EQUIVALENT.

*#2264—Permit-Required Confined Space Entry*

This course is designed to enable students to recognize, evaluate, prevent, and abate safety and health hazards associated with confined space entry. Technical topics include the recognition of confined space hazards, basic information about instrumentation used to evaluate atmospheric hazards, and ventilation techniques. This course features workshops on permit entry classification and program evaluation.

*#3010—Excavation, Trenching and Soil Mechanics*

This course focuses on OSHA standards and on the safety aspects of excavation and trenching. Students are introduced to practical soil mechanics and its relationship to the stability of shored and unshored slopes and walls of excavations. Various types of shoring (wood timbers and hydraulic) are covered. Testing methods are demonstrated and a one-day field exercise is conducted, allowing students to use instruments such as penetrometers, torvane shears, and engineering rods. Prerequisites: All participants must have completed Course #2000, #510, or have equivalent construction training or experience. Industrial hygienists may substitute Course #1010 for #2000.

*#3095—Electrical Standards*

This shortened version of #3090 is designed to provide the student with a survey of OSHA's electrical standards and the hazards associated with electrical installations and equipment. Topics include single- and three-phase systems, cord- and plug-connected and fixed equipment, grounding, ground fault circuit interrupters, and safety-related work practices. Emphasis is placed on electrical hazard recognition and OSHA policies and procedures. Students will receive instruction on safe and correct use of their electrical testing equipment. Prerequisites: All OSHA personnel must have completed Course #2030 or have equivalent training or experience. Other Federal Agency or Department personnel: Course #2005, #6000, or #6010 or equivalent. This course is available to noncompliance personnel only.

*#3110—Fall Arrest Systems*

This course provides an overview of state-of-the-art technology for fall protection and current OSHA requirements. Topics covered include the principles of fall protection, the components of fall arrest systems, the limitations of fall arrest equipment, and OSHA policies regarding fall protection. Course features a one-day field exercise demonstrating fall protection equipment. Prerequisites: All participants must have completed Course #2000, #510, or have equivalent construction training or experience. Industrial hygienists may substitute Course #1010 for #2000.

*#5600—Disaster Site Worker Train-the-Trainer Course*

The Disaster Site Worker Train-the-Trainer Course prepares experienced trainers to present OSHA's 16-hour

Disaster Site Worker Course. Trainers for this course need to be able to apply the elements of successful adult training programs, along with specific knowledge, skills, and attitudes to awareness training about safety and health standards at natural and man-made disaster sites. Trainers are given the opportunity to practice knowledge, skills, and attitudes through discussion, planned exercises, demonstrations, and presentations. Participants receive lesson plans and training materials for the Disaster Site Worker Course as well as information on training techniques and resources. Trainers will be expected to present a selected portion of the Disaster Site Worker Course and to use a ''presentation evaluation'' sheet to evaluate to other presenters. Prerequisite: The intended audience for this course is authorized OSHA #500 trainers who have also completed the 40-hour HAZWOPER training.

*#6000—Collateral Duty Course for Other Federal Agencies*

This course introduces federal agency collateral duty safety and health personnel to the OSH Act, Executive Order 12196, 29 CFR part 1960 and 29 CFR part 1910. The training enables participants to recognize basic safety and health hazards in the workplace and effectively assist agency safety and health officers with inspection and abatement efforts.

*#7000—OSHA's Ergonomics Guidelines Training for Nursing Homes*

The focus of this one-day course is to use OSHA's Ergonomics Guidelines for Nursing Homes to develop a process to protect workers in nursing homes. The course will focus on analyzing and identifying ergonomic problem jobs and practical solutions to address these problems. Featured topics include: Developing an ergonomic process; risk factors in the nursing home guidelines: Identifying problem jobs including protocol for resident assessment; and implementing solutions including work practices and engineering solutions.

*#7005—Public Warehousing and Storage*

The course is designed as a training course for warehouse workers and will focus on many hazards and injuries that are likely to be encountered in warehouse operations. It has been shown that warehousing has become an increasingly hazardous area to work in. OSHA has identified Public Storage and Warehousing as one of seven industries with a high lost time claims rate. Injuries may occur from forklifts; material handling and lifting; exposure to hazardous substances; and slips, trips and falls. The course will discuss: Powered industrial trucks; material handling/lifting/ergonomics; hazard communication; walking and working surfaces; and exit routes and fire protection.

*#7100—Introduction to Machinery and Machine Safeguarding*

The main focus of this course is to increase the participant's knowledge and skill in proper machine safeguarding techniques, and to highlight the benefits of guarding various types of machinery. It is the employer's responsibility to identify and select the safeguard necessary to protect employees and others in the work area, as well as provide appropriate training in safe work practices. Knowing when and how to properly safeguard machinery can reduce or eliminate the potential for accidents and injuries.

*#7105—Evacuation and Emergency Planning*

Evacuation and emergency planning focuses on OSHA requirements for emergency action plans and fire protection plans. Preparing for emergencies is a basic principle of workplace safety and health. Participants will learn: (1) Reasons for emergency action plans and fire prevention plans and when they are required for a workplace; (2) elements of a good evacuation plan; and (3) features of design and maintenance of good exit routes. The optional session for this course will focus on assessment of risk for terrorist attack and how to utilize OSHA's two matrices, evacuation planning and fire and explosion, as tools in planning for emergencies.

*#7200—Bloodborne Pathogens Exposure Control for Healthcare Facilities*

The purpose of this course is to develop a Bloodborne Pathogens Exposure Plan for healthcare facilities using a step-by-step approach. Featured topics include an Introduction to Bloodborne Pathogens Standard, the Exposure Control Plan, Exposure Determination, Methods of Control, Vaccinations and Evaluations, Training and Information, and Record Keeping.

*#7205—Health Hazard Awareness*

This course provides an introduction to common health hazards that are encountered in the workplace. These health hazards will include exposure to chemicals, asbestos, silica, and lead. The course will feature these topics: Identification of hazard; sources of exposure; health hazard information; evaluation of exposure; and engineering and work practice controls. The course materials will include an instructor and student manual; workshops and group activities; and PowerPoint presentations. The course is designed as an awareness course for employers and employees.

*#7300—OSHA's Permit-Required Confined Space Standard*

This one-day course discusses the requirements of OSHA's permit-required confined space standard, 29 CFR 1910.146. It is designed for small employers or a designated representative (line supervisor or manager) with the responsibility to develop a permit space program. It covers OSHA's requirements but does not feature hands-on sections (instrumentation and control methods and testing) which are included in OSHA course #2260.

*#7400—Trainer Course in Construction Noise*

The primary objectives of this one-day course are to increase the participant's knowledge and skill in construction noise and provide them with materials and guidance for training their workers. OSHA published an Advanced Notice for Proposed Rulemaking, Hearing Conservation Program for Construction Workers. This course builds on OSHA's efforts to reduce occupational hearing loss in the construction industry.

*#7405—Fall Hazard Awareness for the Construction Industry*

The focus of this 5-hour course is to identify, evaluate, and prevent or control fall hazards at constructions sites. The course focuses on falls to a lower level not falls to the same level resulting from slips and falls. The target audience is the small construction employer, business owner, or manager who would like to obtain information about fall hazards found in the workplace. The training is also suitable for employees and employee representatives. Topics include identifying fall hazards, analyzing fall hazards, and preventing fall hazards as well as OSHA resources addressing fall hazards.

*#7500—Introduction to Safety and Health Management*

Using interactive assignments and thought-provoking group projects, students of this one day workshop come away with a strong understanding of the benefits in implementing a safety and health management system in the workplace.

*#7505—Introduction to Accident Investigation*

Introduction to accident investigation provides an introduction to basic accident investigation procedures and describes accident analysis techniques. The goal of the course is to help participants gain the basic skills necessary to conduct an effective accident investigation at their workplace. The target audience is the small employer, manager, employee or employee representative who, as part of a firm's safety and health system, would be involved in conducting accident and/or near-miss investigations.

*#7510—Introduction to OSHA for Small Business*

This course provides an introduction to OSHA for owners and managers of small businesses. The goal of the course is to help participants gain an understanding of OSHA operations and procedures and learn how they can work with OSHA to prevent or reduce injuries and illnesses in their workplaces. Included in the course is information on the background of OSHA, standards, the inspection process, implementing a safety and health program, and assistance available to small business. It is anticipated that the course materials could be covered in 3½ to 4 hours.

*#7845—Recordkeeping Rule Seminar*

This course is designed to assist employers in identifying and fulfilling their responsibilities for posting certain records, maintaining records of illnesses and injuries and reporting specific cases to OSHA. Participants who successfully complete this course will be able to identify OSHA requirements and complete new OSHA's forms 300, 300A and 301.

[FR Doc. E7–14049 Filed 7–19–07; 8:45 am]
BILLING CODE 4510–26–P

## LEGAL SERVICES CORPORATION

### Sunshine Act Notice of Meeting Cancellation; Performance Reviews Committee of the Legal Services Corporation's Board of Directors

**TIME AND DATE:** The July 19, 2007 meeting of the Performance Reviews Committee of the Legal Services Corporation's Board of Directors previously noticed in Volume 72, Number 134 of the **Federal Register**, at page 38626, has been cancelled.

**FOR FURTHER INFORMATION CONTACT:** Patricia D. Batie, Manager of Board Operations, at (202) 295–1500.

**SPECIAL NEEDS:** Upon request, meeting notices will be made available in alternate formats to accommodate visual and hearing impairments. Individuals who have a disability and need an accommodation to attend the meeting may notify Patricia D. Batie, at (202) 295–1500.

Dated: July 18, 2007.

**Victor M. Fortuno,**

*Vice President for Legal Affairs, General Counsel & Corporate Secretary.*

[FR Doc. 07–3564 Filed 7–18–07; 1:10 pm]
BILLING CODE 7050–01–P

## NUCLEAR REGULATORY COMMISSION

### Advisory Committee on Reactor Safeguards; Meeting of the ACRS Subcommittee on Plant Operations; Notice of Meeting

The ACRS Subcommittee on Plant Operations will hold a meeting on August 14, 2007, at the U.S. NRC Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas.

The entire meeting will be open to public attendance.

The agenda for the subject meeting shall be as follows:

*Tuesday, August 14, 2007—8:30 a.m. until the conclusion of business.*

The Subcommittee and Region IV will discuss regional inspection, enforcement, and operational activities. The Subcommittee will gather information, analyze relevant issues and facts, and formulate proposed positions and actions, as appropriate, for deliberation by the full Committee.

Members of the public desiring to provide oral statements and/or written comments should notify the Designated Federal Official, Mr. Michael A. Junge (telephone 301–415–6855) five days prior to the meeting, if possible, so that appropriate arrangements can be made. Electronic recordings will be permitted.

Further information regarding this meeting can be obtained by contacting the Designated Federal Official between 6:45 a.m. and 3:30 p.m. (ET). Persons planning to attend this meeting are urged to contact the above named individual at least two working days prior to the meeting to be advised of any potential changes to the agenda.

Dated: July 16, 2007.

**Cayetano Santos,**

*Branch Chief, ACRS.*

[FR Doc. E7–14070 Filed 7–19–07; 8:45 am]
BILLING CODE 7590–01–P

## NUCLEAR REGULATORY COMMISSION

### Sunshine Act Meeting

**DATES:** Week of July 23, 2007.

**PLACE:** Commissioners' Conference Room, 11555 Rockville Pike, Rockville, Maryland.

**STATUS:** Public and Closed.

**ADDITIONAL MATTERS TO BE CONSIDERED:**

**Week of July 23, 2007—Tentative**

*Tuesday, July 24, 2007*

1:55 p.m. Affirmation Session (Public Meeting) (Tentative). a. Request for Reconsideration of the Wording of 10 CRF Sec. 26.205(D)(4) as Affirmed on April 17, 2007 (Tentative).

This meeting will be webcast live at the Web address—*http://www.nrc.gov*.

* * * * *

*The schedule for Commission meetings is subject to change on short notice. To verify the status of meetings call (recording)—(301) 415–1292. Contact person for more information: Michelle Schroll, (301) 415–1662.

* * * * *

The NRC Commission Meeting Schedule can be found on the Internet at: *http://www.nrc.gov/what-we-do/policy-making/schedule.html.*

* * * * *

The NRC provides reasonable accommodation to individuals with disabilities where appropriate. If you need a reasonable accommodation to participate in these public meetings, or need this meeting notice or the transcript or other information from the public meetings in another format (e.g., braille, large print), please notify the NRC's Disability Program Coordinator, Rohn Brown, at 301–415–2279, TDD: 301–415–2100, or by e-mail at *REB3@nrc.gov*. Determinations on requests for reasonable accommodation will be made on a case-by-case basis.

* * * * *

This notice is distributed by mail to several hundred subscribers; if you no longer wish to receive it, or would like to be added to the distribution, please contact the Office of the Secretary, Washington, DC 20555 (301–415–1969). In addition, distribution of this meeting notice over the Internet system is available. If you are interested in receiving this Commission meeting schedule electronically, please send an electronic message to *dkw@nrc.gov*.

Dated: July 17, 2007.

**R. Michelle Schroll,**

*Office of the Secretary.*

[FR Doc. 07–3556 Filed 7–18–07; 10:46 am]

**BILLING CODE 7690–01–P**

## POSTAL REGULATORY COMMISSION

### Briefing on Industry Service Tracking System

**AGENCY:** Postal Regulatory Commission.

**ACTION:** Notice of briefing.

**SUMMARY:** Representatives from the Red Tag News Publications will present a briefing on Tuesday, July 24, 2007, beginning at 10 a.m., in the Postal Regulatory Commission's main conference room. The briefing will address service standard measurement for certain Periodicals mailings. The briefing is open to the public.

**DATES:** July 24, 2007.

**ADDRESSES:** Postal Regulatory Commission, 901 New York Avenue, NW., Suite 200, Washington, DC 20268–0001.

**FOR FURTHER INFORMATION CONTACT:** Ann C. Fisher, Chief of Staff, Postal Regulatory Commission, 202–789–6803.

**Steven W. Williams,**

*Secretary.*

[FR Doc. 07–3545 Filed 7–19–07; 8:45 am]

**BILLING CODE 7710–FW–M**

## SECURITIES AND EXCHANGE COMMISSION

**[Release No. IC–27886; File No. 812–13333]**

### Delaware VIP Trust et al., Notice of Application

July 16, 2007.

**AGENCY:** Securities and Exchange Commission (''SEC'' or the ''Commission'').

**ACTION:** Notice of application (''Application'') for exemption, pursuant to section 6(c) of the Investment Company Act of 1940, as amended (the ''1940 Act''), from the provisions of sections 9(a), 13(a), 15(a) and 15(b) of the Act and Rules 6e–2(b)(15) and 6e–3(T)(b)(15) thereunder.

Applicants: Delaware VIP Trust (the ''Fund'') and Delaware Management Company, a series of Delaware Management Business Trust and investment manager to the Fund (''DMC'') (collectively the ''Applicants'').

**SUMMARY:** Applicants request an order exempting them from the provisions of sections 9(a), 13(a), 15(a) and 15(b) of the Act and Rules 6e–2(b)(15) and 6e–3(T)(b)(15) thereunder, to the extent necessary to permit shares of the Fund and shares of any other investment company or portfolio that is designed to fund insurance products and for which DMC or any of its affiliates, may serve in the future as investment adviser, manager, principal underwriter, sponsor, or administrator (''Future Funds'') (the Fund, together with Future Funds, the ''Funds'') to be sold to and held by: (a) Separate accounts funding variable annuity contracts and variable life insurance policies (collectively ''Variable Contracts'') issued by both affiliated life insurance companies and unaffiliated life insurance companies; (b) trustees of qualified group pension and group retirement plans outside of the separate account context (''Qualified Plans''); (c) separate accounts that are not registered as investment companies under the 1940 Act pursuant to exemptions from registration under section 3(c) of the 1940 Act; (d) DMC or its affiliates who serve or may serve as an investment manager, investment adviser, principal underwriter, sponsor or administrator of a Fund (collectively, ''DMC Entities'') for the purpose of providing initial capital to a Fund; and (e) any other account of a Participating Insurance Company permitted to hold shares of the Funds (''General Account'').

**DATES:** The Application was filed on September 26, 2006, and amended on July 11, 2007. Hearing or Notification of Hearing: An order granting the application will be issued unless the Commission orders a hearing. Interested persons may request a hearing by writing to the Secretary of the Commission and serving Applicants with a copy of the request, personally or by mail. Hearing requests should be received by the Commission by 5:30 p.m. on August 8, 2007, and should be accompanied by proof of service on Applicants in the form of an affidavit or, for lawyers, a certificate of service. Hearing requests should state the nature of the requester's interest, the reason for the request, and the issues contested. Persons who wish to be notified of a hearing may request notification by writing to the Secretary of the Commission.

**ADDRESSES:** The Commission: Secretary, Securities and Exchange Commission, 100 F Street, NE., Washington, DC 20549–1090; Applicants: David P. O'Connor, Esq. c/o Delaware VIP Trust, 2005 Market Street, Philadelphia, Pennsylvania 19103.

**FOR FURTHER INFORMATION CONTACT:** Rebecca A. Marquigny, Senior Counsel, or Joyce M. Pickholz, Branch Chief, Office of Insurance Products, Division of Investment Management, at (202) 551–6795.

**SUPPLEMENTARY INFORMATION:** The following is a summary of the Application. The complete Application is available for a fee from the SEC's Public Reference Branch, 100 F Street, NE., Room 1580, Washington, DC 20549 (telephone (202) 551–8090).

### Applicant's Representations

1. The Fund (File No. 811–05162) is registered under the 1940 Act as an open-end management investment company comprised of and offering shares of beneficial interest (''shares'') in 15 investment portfolios (each a ''Portfolio'' and, collectively, the ''Portfolios''). The Fund or any Future Funds may offer one or more additional investment portfolios in the future (also referred to as ''Portfolios''). Applicants state that the Fund's shares are registered under the Securities Act of 1933, as amended (the ''1933 Act'') (File No. 033–14363) and the investment manager to the Fund, DMC, is registered with the Commission as an investment adviser under the Investment Advisers Act of 1940, as amended.

2. Applicants represent that there will be no public shareholders of any Portfolio. Applicants state that pursuant to exemptive relief provided in a 1987 SEC order (Rel. IC–16105), Fund shares are being offered to both affiliated and unaffiliated insurance company separate accounts funding variable annuity or variable life insurance products. Applicants state that separate accounts which currently or in the future may hold shares are (or will be) registered as unit investment trusts under the 1940 Act or exempt from such registration (individually, a ''Separate Account'' and collectively, ''Separate Accounts''). Insurance companies whose Separate Account(s) may now or in the future own shares are referred to herein as ''Participating Insurance Companies.''

3. Applicants propose that the Funds be permitted to offer and/or sell shares to Separate Accounts funding Variable Contracts issued by Participating Insurance Companies. Applicants represent that the Participating Insurance Companies at the time of their investment in the Funds either have or will establish their own Separate Accounts and design their own Variable Contracts. Each Participating Insurance Company has or will have the legal obligation of satisfying all applicable requirements under both state and

federal law. Applicants represent that each Participating Insurance Company, on behalf of its Separate Accounts, has or will enter into an agreement with the Funds concerning such Participating Insurance Company's participation in the relevant Portfolio (a ''Participation Agreement''). The role of the Funds under this agreement, insofar as the federal securities laws are applicable, will consist of, among other things, offering shares of the Portfolios to the participating Separate Accounts and complying with any conditions that the Commission may impose.

4. Applicants propose that the Funds be permitted to offer and/or sell Shares to Qualified Plans. section 817(h) of the Internal Revenue Code of 1986, as amended (the ''Code''), imposes certain diversification standards on the assets underlying Variable Contracts, such as those in each Portfolio. The Code provides that Variable Contracts will not be treated as annuity contracts or life insurance contracts for any period (or any subsequent period) for which the underlying assets are not, in accordance with regulations issued by the Treasury Department (individually, a ''Treasury Regulation'' and collectively the ''Treasury Regulations''), adequately diversified. section 817(h) of the Code and the Regulations thereunder provide, in general, that the ability to look through to the assets of an underlying fund in applying the diversification test is only available if all of the beneficial interests in the investment company are held by the segregated asset accounts of one or more insurance companies. However, the Regulations contain certain exceptions to this requirement, one of which allows shares in an underlying mutual fund to be held by the trustees of a qualified pension or retirement plan without adversely affecting the tax status of Variable Contracts. (Treas. Reg. 1.817–5(f)(3)(iii)). Applicants represent that as a result of this exception to the general diversification requirement, shares of the Portfolios sold to the Qualified Plans would be held by the trustees of such Qualified Plans as required by section 403(a) of the Employee Retirement Income Security Act, as amended (''ERISA'').

5. Applicants also propose that the Funds be permitted to offer and/or sell shares to DMC Entities for the purpose of providing initial capital to a Fund and to General Accounts. The Regulations permit sales of Portfolio shares to General Accounts and DMC Entities so long as the return on shares held by each is computed in the same manner as for shares held by a Separate Account, and the General Accounts and DMC Entities do not intend to sell shares of the Portfolio held by it to the Public. The Regulations impose an additional restriction on sales to investment advisers, who may hold shares only in connection with the creation of the Portfolio. Applicants anticipate that sales in reliance on these provisions of the Regulations will be made to DMC Entities for purposes of providing the initial capital for a Fund and that any Portfolio shares purchased by DMC Entities will be redeemed immediately if and when a DMC Entity no longer serves as an investment adviser to such Portfolio.

**Applicants' Legal Analysis**

1. In connection with the funding of scheduled premium variable life insurance contracts issued through a Separate Account registered as a unit investment trust (''UIT'') under the 1940 Act, Rule 6e–2(b)(15) provides partial exemptions from sections 9(a), 13(a), 15(a) and 15(b) of the 1940 Act. Section 9(a)(2) of the 1940 Act makes it unlawful for any company to serve as an investment adviser or principal underwriter of any UIT, if an affiliated person of that company is subject to a disqualification enumerated in section 9(a)(1) or (2) of the 1940 Act. Sections 13(a), 15(a) and 15(b) of the 1940 Act have been deemed by the Commission to require ''pass-through'' voting with respect to an underlying investment company's shares. Rule 6e–2(b)(15) provides these exemptions apply only where all of the assets of the UIT are shares of management investment companies ''which offer their shares exclusively to variable life insurance separate accounts of the life insurer or of any affiliated life insurance company.'' Therefore, the relief granted by Rule 6e–2(b)(15) is not available with respect to a scheduled premium life insurance Separate Account that owns shares of an underlying fund that also offers its shares to a variable annuity Separate Account or flexible premium variable life insurance Separate Account of the same company or any other affiliated insurance company. The use of a common management investment company as the underlying investment vehicle for both variable annuity and variable life insurance separate accounts of the same life insurance company or of any affiliated life insurance company is referred to herein as ''mixed funding.''

2. The relief granted by Rule 6e–2(b)(15) also is not available with respect to a scheduled premium variable life insurance Separate Account that owns shares of an underlying fund that also offers its shares to Separate Accounts funding Variable Contracts of one or more unaffiliated life insurance companies. The use of a common management investment company as the underlying investment vehicle for variable annuity and/or variable life insurance Separate Accounts of unaffiliated life insurance companies is referred to herein as ''shared funding.''

3. The relief under Rule 6e–2(b)(15) is available only where shares are offered exclusively to variable life insurance Separate Accounts of a life insurer or any affiliated life insurance company; additional exemptive relief is necessary if the shares of the Portfolios are also to be sold to Qualified Plans, DMC Entities and General Accounts (collectively ''Eligible Purchasers''). Applicants note that if shares of the Portfolios are sold only to Qualified Plans, exemptive relief under Rule 6e–2 would not be necessary. The relief provided for under this section does not relate to Qualified Plans or to a registered investment company's ability to sell its shares to Qualified Plans. The use of a common management investment company as the underlying investment vehicle for variable annuity and variable life Separate Accounts of affiliated and unaffiliated insurance companies, and for Qualified Plans, is referred to herein as ''extended mixed and shared funding.''

4. In connection with flexible premium variable life insurance contracts issued through a separate account registered under the 1940 Act as a UIT, Rule 6e–3(T)(b)(15) provides partial exemptions from sections 9(a), 13(a), 15(a) and 15(b) of the 1940 Act. The exemptions granted by Rule 6e–3(T)(b)(15) are available only where all the assets of the Separate Account consist of the shares of one or more registered management investment companies that offer to sell their shares ''exclusively to separate accounts of the life insurer, or of any affiliated life insurance companies, offering either scheduled contracts or flexible contracts, or both; or which also offer their shares to variable annuity separate accounts of the life insurer or of an affiliated life insurance company or which offer their shares to any such life insurance company in consideration solely for advances made by the life insurer in connection with the operation of the separate account.'' Therefore, Rule 6e–3(T)(b)(15) permits mixed funding but does not permit shared funding.

5. Because the relief under Rule 6e–3(T) is available only where shares are offered exclusively to variable life insurance separate accounts of a life insurer or any affiliated life insurance

company, additional exemptive relief is necessary if the shares of the Portfolios are also to be sold to Eligible Purchasers, as described above. Applicants note that if shares of the Portfolios were sold only to Qualified Plans, exemptive relief under Rule 6e–3(T)(b)(15) would not be necessary. The relief provided for under this section does not relate to Qualified Plans or to a registered investment company's ability to sell its shares to Qualified Plans.

6. Applicants maintain, as discussed below, that there is no policy reason for the sale of the Portfolios' shares to Eligible Purchasers to result in a prohibition against, or otherwise limit a Participating Insurance Company from relying on the relief provided by Rules 6e–2(b)(15) and 6e–3(T)(b)(15). However, because the relief under Rules 6e–2(b)(15) and 6e–3(T)(b)(15) is available only when shares are offered exclusively to Separate Accounts, additional exemptive relief may be necessary if the shares of the Portfolios are also to be sold to Eligible Purchasers. Applicants therefore request relief in order to have the Participating Insurance Companies enjoy the benefits of the relief granted in Rules 6e–2(b)(15) and 6e–3(T)(b)(15). Applicants note that if the Portfolios' shares were to be sold only to Eligible Purchasers and/or Separate Accounts funding variable annuity contracts, exemptive relief under Rule 6e–2 and Rule 6e–3(T) would be unnecessary. The relief provided for under Rules 6e–2(b)(15) and 6e–3(T)(b)(15) does not relate to Qualified Plans, DMC Entities, or General Accounts, or to a registered investment company's ability to sell its shares to such purchasers.

7. Consistent with the Commission's authority under section 6(c) of the 1940 Act to grant exemptive orders to a class or classes of persons and transactions, the Application requests relief for the class consisting of Participating Insurance Companies and their Separate Accounts that will invest in the Portfolios, and, to the extent necessary, Qualified Plans, investment advisers, principal underwriters and depositors of such Separate Accounts.

8. In effect, the partial relief granted in Rules 6e–2(b)(15) and 6e–3(T)(b)(15) under the 1940 Act from the requirements of section 9 of the 1940 Act limits the amount of monitoring necessary to ensure compliance with section 9 to that which is appropriate in light of the policy and purposes of section 9. Those rules recognize that it is not necessary for the protection of investors or the purposes fairly intended by the policy and provisions of the 1940 Act to apply the provisions of section 9(a) to individuals in a large insurance company complex, most of whom will have no involvement in matters pertaining to investment companies in that organization. Applicants assert that the Participating Insurance Companies and Qualified Plans are not expected to play any role in the management of the Funds and that those individuals who participate in the management of the Funds will remain the same regardless of which Separate Accounts or Qualified Plans invest in the Funds. Applicants argue that applying the monitoring requirements of section 9(a) of the 1940 Act because of investment by separate accounts of other insurers or Qualified Plans would be unjustified, would not serve any regulatory purpose and monitoring costs could reduce the net rates of return realized by contract owners due to the increased monitoring costs.

9. Rules 6e–2(b)(15)(iii) and 6e–3(T)(b)(15)(iii) under the 1940 Act provide exemptions from the pass-through voting requirement with respect to several significant matters, assuming the limitations on mixed and shared funding are observed. Rules 6e–2(b)(15)(iii)(A) and 6e–3(T)(b)(15)(iii)(A) provide that the insurance company may disregard the voting instructions of its contract owners with respect to the investments of an underlying fund, or any contract between such a fund and its investment adviser, when required to do so by an insurance regulatory authority (subject to the provisions of paragraphs (b)(5)(i) and (b)(7)(ii)(A) of Rules 6e–2 and 6e–3(T), respectively, under the 1940 Act). Rules 6e–2(b)(15)(iii)(B) and 6e–3(T)(b)(15)(iii)(A)(2) provide that the insurance company may disregard the voting instructions of its contract owners if the contract owners initiate any change in an underlying fund's investment policies, principal underwriter, or any investment adviser (provided that disregarding such voting instructions is reasonable and subject to the other provisions of paragraphs (b)(5)(ii), (b)(7)(ii)(B), and (b)(7)(ii)(C), respectively, of Rules 6e–2 and 6e–3(T) under the 1940 Act).

10. Rule 6e–2 under the 1940 Act recognizes that a variable life insurance contract, as an insurance contract, has important elements unique to insurance contracts and is subject to extensive state regulation of insurance. In adopting Rule 6e–2(b)(15)(iii), the Commission expressly recognized that state insurance regulators have authority, pursuant to state insurance laws or regulations, to disapprove or require changes in investment policies, investment advisers, or principal underwriters. The Commission also expressly recognized that state insurance regulators have authority to require an insurer to draw from its general account to cover costs imposed upon the insurer by a change approved by contract owners over the insurer's objection. The Commission, therefore, deemed such exemptions necessary "to assure the solvency of the life insurer and performance of its contractual obligations by enabling an insurance regulatory authority or the life insurer to act when certain proposals reasonably could be expected to increase the risks undertaken by the life insurer." In this respect, flexible premium variable life insurance contracts are identical to scheduled premium variable life insurance contracts. Applicants, therefore, assert that the corresponding provisions of Rule 6e–3(T) under the 1940 Act undoubtedly were adopted in recognition of the same factors.

11. Applicants also assert that the sale of Shares to Qualified Plans, the Investment Manager and General Accounts will not have any impact on the relief requested. With respect to the Qualified Plans, which are not registered as investment companies under the 1940 Act, shares of a portfolio of a fund sold to a Qualified Plan must be held by the trustees of the Qualified Plan pursuant to section 403(a) of the Employee Retirement Income Security Act, as amended ("ERISA"). Applicants note that (1) section 403(a) of ERISA endows Qualified Plan trustees with the exclusive authority and responsibility for voting proxies provided neither of two enumerated exceptions to that provision applies; (2) some of the Qualified Plans, may provide for the trustee(s), an investment adviser (or advisers), or another named fiduciary to exercise voting rights in accordance with instructions from participants; and (3) there is no requirement to pass through voting rights to Qualified Plan participants.

12. Applicants argue that an Investment Manager and General Accounts are similar in that they are not subject to any pass-through voting requirements. Applicants therefore conclude that, unlike the case with insurance company Separate Accounts, the issue of resolution of material irreconcilable conflicts with respect to voting is not present with Eligible Purchasers.

13. Applicants represent that where a Qualified Plan does not provide participants with the right to give voting instructions, the trustee or named fiduciary has responsibility to vote the shares held by the Qualified Plan in the

best interest of the Qualified Plan participants. Accordingly, Applicants argue that even if DMC or an affiliate of DMC were to serve in the capacity of trustee or named fiduciary with voting responsibilities, DMC or the affiliates would have a fiduciary duty to vote those shares in the best interest of the Qualified Plan participants.

14. Further, Applicants assert that even if a Qualified Plan were to hold a controlling interest in a Portfolio, Applicants do not believe that such control would disadvantage other investors in such Portfolio to any greater extent than is the case when any institutional shareholder holds a majority of the voting securities of any open-end management investment company. In this regard, Applicants submit that investment in a Portfolio by a Qualified Plan will not create any of the voting complications occasioned by mixed funding or shared funding. Unlike mixed funding or shared funding, Applicants argue that Qualified Plan investor voting rights cannot be frustrated by veto rights of insurers or state regulators.

15. Where a Qualified Plan provides participants with the right to give voting instructions, Applicants see no reason to believe that participants in Qualified Plans generally or those in a particular Qualified Plan, either as a single group or in combination with participants in other Qualified Plans, would vote in a manner that would disadvantage Variable Contract holders. Applicants assert that the purchase of Shares by Qualified Plans that provide voting rights does not present any complications not otherwise occasioned by mixed or shared funding.

16. Applicants do not believe that sale of the shares of the Portfolios to Qualified Plans will increase the potential for material irreconcilable conflicts of interest between or among different types of investors. In particular, Applicants see very little potential for such conflicts beyond those which would otherwise exist between variable annuity and variable life insurance contract owners.

17. Unlike the circumstances of many investment companies that serve as underlying investment media for variable insurance products, the Fund may be deemed to lack an insurance company ''promoter'' for purposes of Rule 14a–2 under the 1940 Act. Accordingly, the Fund and any other such Future Funds or Portfolios that are established as new registrants will be subject to the requirements of section 14(a) of the 1940 Act, which generally requires that an investment company have a net worth of $100,000 upon making a public offering of its shares. Portfolios also will require more limited amounts of initial capital in connection with the creation of new series and the voting of initial shares of such series on matters requiring the approval of shareholders. A potential source of the requisite initial capital is a Portfolio's adviser or a Participating Insurance Company. Either of these parties may have an interest in making the requisite capital investments. Applicants note, however, that the provision of initial capital may be deemed to violate the exclusivity requirement of Rule 6e–2(b)(15) and/or Rule 6e–3(T)(b)(15).

18. Given the conditions of Treas. Reg. 1.817–5(f)(3) and the harmony of interest between a Portfolio, on the one hand, and DMC Entities or a Participating Insurance Company, on the other, Applicants assert that little incentive for overreaching exists. Applicants further assert that such investment should not implicate the concerns discussed above regarding the creation of material irreconcilable conflicts. Instead, Applicants argue that permitting investment by DMC Entities or Participating Insurance Companies' General Accounts will permit the orderly and efficient creation of the Funds or series thereof, and reduce the expense and uncertainty of using outside parties at the early stages of Portfolio operations.

**Applicants' Conditions**

Applicants agree that the order granting the requested relief shall be subject to the following conditions:

1. A majority of the Board of Trustees (the ''Board'') of the Fund will consist of persons who are not ''interested persons'' of the Fund, as defined by section 2(a)(19) of the 1940 Act, and the rules thereunder, and as modified by any applicable orders of the Commission, except that if this condition is not met by reason of the death, disqualification, or bona-fide resignation of any trustee or trustees, then the operation of this condition will be suspended: (a) For a period of 90 days if the vacancy or vacancies may be filled by the Board; (b) for a period of 150 days if a vote of shareholders is required to fill the vacancy or vacancies; or (c) for such longer period as the Commission may prescribe by order upon application or by future rule.

2. The Board will monitor the Fund for the existence of any material irreconcilable conflict between the interests of the contract owners of all Separate Accounts and participants of all Qualified Plans investing in the Fund, and determine what action, if any should be taken in response to such conflicts. A material irreconcilable conflict may arise for a variety of reasons, including: (a) An action by any state insurance regulatory authority; (b) a change in applicable federal or state insurance, tax, or securities laws or regulations, or a public ruling, private letter ruling, no-action or interpretative letter, or any similar action by insurance, tax, or securities regulatory authorities; (c) an administrative or judicial decision in any relevant proceeding; (d) the manner in which the investments of the Fund are being managed; (e) a difference in voting instructions given by variable annuity contract owners, variable life insurance contract owners, and trustees of the Qualified Plans; (f) a decision by a Participating Insurance Company to disregard the voting instructions of contract owners; or (g) if applicable, a decision by a Qualified Plan to disregard the voting instructions of Qualified Plan participants.

3. Participating Insurance Companies (on their own behalf, as well as by virtue of any investment of general account assets in a Portfolio), DMC Entities, and any trustee on behalf of a Qualified Plan that executes a Participation Agreement upon becoming an owner of 10 percent or more of the assets of any Portfolio (collectively, ''Participants'') will report any potential or existing conflicts to the Board. Participants will be responsible for assisting the Board in carrying out the Board's responsibilities under these conditions by providing the Board with all information reasonably necessary for the Board to consider any issues raised. This responsibility includes, but is not limited to, an obligation of each Participating Insurance Company to inform the Board whenever contract owner voting instructions are disregarded, and, if pass-through voting is applicable, an obligation of each of the trustees on behalf of a Qualified Plan to inform the Board whenever it has determined to disregard Qualified Plan participant voting instructions. The responsibility to report such information and conflicts, and to assist the Board, will be a contractual obligation of all Participating Insurance Companies under their Participation Agreements with the Fund, and these responsibilities will be carried out with a view only to the interests of the contract owners. The responsibility to report such information and conflicts, and to assist the Board, also will be contractual obligations of all Qualified Plans under their Participation Agreements, and such agreements will provide that these responsibilities will

be carried out with a view only to the interests of Qualified Plan participants.

4. If it is determined by a majority of the Board or a majority of the disinterested trustees of the Board, that a material irreconcilable conflict exists, then the relevant Participant will, at its expense and to the extent reasonably practicable (as determined by a majority of the disinterested trustees), take whatever steps are necessary to remedy or eliminate the material irreconcilable conflict, up to and including: (a) Withdrawing the assets allocable to some or all of the Separate Accounts from the relevant Portfolio and reinvesting such assets in a different investment vehicle including another Portfolio, or in the case of a Participating Insurance Company Participant submitting the question as to whether such segregation should be implemented to a vote of all affected contract owners and, as appropriate, segregating the assets of any appropriate group (i.e., annuity contract owners or life insurance contract owners of one or more Participating Insurance Companies) that votes in favor of such segregation, or offering to the affected contract owners the option of making such a change; and (b) establishing a new registered management investment company or managed separate account. If a material irreconcilable conflict arises because of a decision by a Participating Insurance Company to disregard contract owner voting instructions, and that decision represents a minority position or would preclude a majority vote, then the insurer may be required, at the election of the Fund, to withdraw such insurer's Separate Account's investment in the Fund, and no charge or penalty will be imposed as a result of such withdrawal. If a material irreconcilable conflict arises because of a Qualified Plan's decision to disregard Qualified Plan participant voting instructions, if applicable, and that decision represents a minority position or would preclude a majority vote, the Qualified Plan may be required, at the election of the Fund, to withdraw its investment in the Fund, and no charge or penalty will be imposed as a result of such withdrawal. The responsibility to take remedial action in the event of a Board determination of a material irreconcilable conflict and to bear the cost of such remedial action will be a contractual obligation of all Participants under their agreements governing participation in the Fund, and these responsibilities will be carried out with a view only to the interests of contract owners and Qualified Plan participants.

For purposes of this Condition 4, a majority of the disinterested members of the Board Fund will determine whether or not any proposed action adequately remedies any material irreconcilable conflict, but, in no event will the Fund, DMC or an affiliate of DMC, as relevant, be required to establish a new funding vehicle for any Variable Contract. No Participating Insurance Company will be required by this Condition 4 to establish a new funding vehicle for any Variable Contract if any offer to do so has been declined by vote of a majority of the contract owners materially and adversely affected by the material irreconcilable conflict. Further, no Qualified Plan will be required by this Condition 4 to establish a new funding vehicle for the Qualified Plan if: (a) A majority of the Qualified Plan participants materially and adversely affected by the irreconcilable material conflict vote to decline such offer, or (b) pursuant to documents governing the Qualified Plan, the Qualified Plan makes such decision without a Qualified Plan participant vote.

5. The Board's determination of the existence of a material irreconcilable conflict and its implications will be made known in writing promptly to all Participants.

6. As to Variable Contracts issued by Separate Accounts registered under the 1940 Act, Participating Insurance Companies will provide pass-through voting privileges to all Variable Contract owners as required by the 1940 Act as interpreted by the Commission. However, as to Variable Contracts issued by unregistered Separate Accounts, pass-through voting privileges will be extended to contract owners to the extent granted by the issuing insurance company. Accordingly, such Participants, where applicable, will vote shares of the applicable Portfolio held in their Separate Accounts in a manner consistent with voting instructions timely received from Variable Contract owners. Participating Insurance Companies will be responsible for assuring that each Separate Account investing in a Portfolio calculates voting privileges in a manner consistent with other Participants.

The obligation to calculate voting privileges as provided in the Application will be a contractual obligation of all Participating Insurance Companies under their agreement with the Funds governing participation in a Portfolio. Each Participating Insurance Company will vote shares for which it has not received timely voting instructions, as well as shares held in its General Account or otherwise attributed to it, in the same proportion as it votes those shares for which it has received voting instructions. Each Qualified Plan will vote as required by applicable law and governing Qualified Plan documents.

7. As long as the 1940 Act requires pass-through voting privileges to be provided to variable contract owners, DMC Entities and any General Account will vote its shares of any Portfolio in the same proportion as all variable contract owners having voting rights with respect to that Portfolio; provided, however, that DMC Entities or any insurance company General Account shall vote its shares in such other manner as may be required by the Commission or its staff.

8. The Fund will comply with all provisions of the 1940 Act requiring voting by shareholders, which for these purposes, shall be the persons having a voting interest in the shares of the respective Portfolio, and, in particular, the Fund will either provide for annual meetings (except to the extent that the Commission may interpret section 16 of the 1940 Act not to require such meetings) and will comply with section 16(a) of the 1940 Act, section 16(c) of the 1940 Act (although the Fund is not one of those trusts of the type described in section 16(c) of the 1940 Act) and, if and when applicable, section 16(b) of the 1940 Act. Further, the Fund will act in accordance with the Commission's interpretation of the requirements of section 16(a) with respect to periodic elections of directors/trustees and with whatever rules the Commission may promulgate with respect thereto.

9. A Portfolio will make its shares available under Variable Contracts and to Qualified Plans at or about the same time it accepts any seed capital from DMC Entities or a General Account of a Participating Insurance Company.

10. The Fund will notify all Participants that Separate Account prospectus disclosure or Qualified Plan prospectuses or other Qualified Plan disclosure documents regarding potential risks of mixed and shared funding may be appropriate. The Fund will disclose in its prospectus that (a) shares of the Fund may be offered to Separate Accounts of both variable annuity and variable life insurance contracts and, if applicable, to Qualified Plans; (b) due to differences in tax treatment and other considerations, the interests of various contract owners participating in the Fund and the interests of Qualified Plans investing in the Fund, if applicable, may conflict; and (c) the Fund's Board will monitor events in order to identify the existence of any material irreconcilable conflicts

and to determine what action, if any, should be taken in response to any such conflict.

11. If and to the extent that Rule 6e–2 and Rule 6e–3(T) under the 1940 Act are amended, or proposed Rule 6e–3 under the 1940 Act is adopted, to provide exemptive relief from any provision of the 1940 Act, or the rules promulgated thereunder, with respect to mixed or shared funding, on terms and conditions materially different from any exemptions granted in the order requested in the Application, then the Fund and/or Participating Insurance Companies, as appropriate, shall take such steps as may be necessary to comply with Rules 6e–2 and 6e–3(T), or Rule 6e–3, as such rules are applicable.

12. The Participants, at least annually, will submit to the Board such reports, materials, or data as a Board reasonably may request so that the trustees of the Board may fully carry out the obligations imposed upon the Board by the conditions contained in the Application. Such reports, materials, and data will be submitted more frequently if deemed appropriate by the Board. The obligations of the Participants to provide these reports, materials, and data to the Board, when it so reasonably requests, will be a contractual obligation of all Participants under their agreements governing participation in the Portfolios.

13. All reports of potential or existing conflicts received by the Board, and all Board action with regard to determining the existence of a conflict, notifying Participants of a conflict, and determining whether any proposed action adequately remedies a conflict, will be properly recorded in the minutes of the Board or other appropriate records, and such minutes or other records shall be made available to the Commission upon request.

14. The Fund will not accept a purchase order from a Qualified Plan if such purchase would make the Qualified Plan shareholder an owner of 10 percent or more of the assets of a Portfolio unless the Trustees of such Qualified Plan execute an agreement with the Fund governing participation in such Portfolio that includes the conditions set forth herein to the extent applicable. The Trustees of a Qualified Plan will execute an application containing an acknowledgment of this condition at the time of its initial purchase of shares of any Portfolio.

**Conclusions**

Applicants submit that, for the reasons summarized above and to the extent necessary or appropriate to provide for the transactions described herein, the requested exemptions from sections 9(a), 13(a), 15(a), and 15(b) of the 1940 Act and Rules 6e–2(b)(15) and 6e–3(T)(b)(15) thereunder, in accordance with the standards of section 6(c) of the 1940 Act, are in the public interest and consistent with the protection of investors and the purposes fairly intended by the policy and provisions of the 1940 Act.

For the Commission, by the Division of Investment Management, pursuant to delegated authority.

**Florence E. Harmon,**

*Deputy Secretary.*

[FR Doc. E7–14028 Filed 7–19–07; 8:45 am]

BILLING CODE 8010–01–P

## SECURITIES AND EXCHANGE COMMISSION

**[Release No. 34–56064; File No. SR–CHX–2006–42]**

## Self-Regulatory Organizations; Chicago Stock Exchange, Inc.; Notice of Filing of Proposed Rule Change, as Modified by Amendment No. 1 Thereto, To Modify Provisions Relating to Cross With Yield Orders

July 13, 2007.

Pursuant to section 19(b)(1) of the Securities Exchange Act of 1934 (''Act''),[1] and Rule 19b–4 thereunder,[2] notice is hereby given that on December 22, 2006, the Chicago Stock Exchange, Inc. (''CHX'' or ''Exchange'') filed with the Securities and Exchange Commission (''Commission'') the proposed rule change as described in Items I, II, and III below, which Items have been substantially prepared by the CHX. On July 6, 2007, the Exchange filed Amendment No. 1 to the proposed rule change.[3] The Commission is publishing this notice to solicit comments on the proposed rule change, as amended, from interested persons.

### I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The CHX proposes to amend its rules to permit participants submitting ''cross with yield'' orders to elect to yield to undisplayed interest. The text of this proposed rule change is available at the Exchange, on the Exchange's Web site at: *http://www.chx.com/rules/proposed_rules.htm*, and in 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 CHX 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 CHX 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

As part of the Exchange's new trading model, the CHX offers its participants a wide variety of order types that may be submitted to the CHX and its central matching engine (''Matching System'').[4] As the CHX and its participants gain familiarity with this new trading model, further dialogue with participant firms, as well as industry developments, will likely necessitate further refinement of the CHX new trading model rules, including the sort of order type enhancement proposed in this submission.

This proposed rule change would amend the definition of a ''cross with yield'' order to permit a CHX participant to elect to yield to undisplayed market interest in addition to bids and offers that are displayed in the Matching System. This change is consistent with the purpose of a cross with yield order—a participant selects this type of order because it wants its customer order to interact with available market interest. This proposal, which simply expands the types of orders to which a participant's interest would yield, is reflected in changes to Article 1, Rule 2(h) and Article 20, Rules 4(b)(7) and 8(e) of the Exchange's rules.

2. Statutory Basis

The CHX believes the proposal is consistent with the requirements of the Act and the rules and regulations

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] Amendment No. 1, which replaced the original filing in its entirety, removed a proposal that would have allowed the Exchange's Matching System to reprice sell short mid-point cross orders. The Exchange believes that such repricing is no longer necessary due to the Commission's recent decision to eliminate Rule 10a–1 and all similar pricing tests that might be applied to sell short orders. *See* Securities Exchange Act Release No. 55970 (June 28, 2007), 72 FR 36348 (July 3, 2007). Amendment No. 1 also removed a proposed effective date for the new order type and made other small wording changes to the narrative description.

[4] *See, e.g.*, CHX Article 1, Rule 2 and CHX Article 20, Rule 4 (outlining the range of available order types).

thereunder that are applicable to a national securities exchange, and, in particular, with the requirements of section 6(b).[5] The CHX believes the proposal is consistent with section 6(b)(5) of the Act[6] in that it is designed to promote just and equitable principles of trade, to remove impediments to, and to 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 permitting the Exchange to further refine its product offerings.

*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.

*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**

Within 35 days of the date of publication of this notice in the **Federal Register** or within such longer period (i) as the Commission may designate up to 90 days of such date if it finds such longer period to be appropriate and publishes its reasons for so finding or (ii) as to which the Exchange consents, the Commission will:

(A) By order approve such proposed rule change, or

(B) institute proceedings to determine whether the proposed rule change should be disapproved.

**IV. Solicitation of Comments**

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

*Electronic Comments*

• Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or

• Send an e-mail to: *rule-comments@sec.gov.* Please include File Number SR–CHX–2006–42 on the subject line.

*Paper Comments*

• Send paper comments in triplicate to Nancy M. Morris, Secretary, Securities and Exchange Commission, 100 F Street, NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–CHX–2006–42. This file number should be included on the subject line if e-mail is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for inspection and copying in the Commission's Public Reference Room, 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–CHX–2006–42 and should be submitted on or before August 10, 2007.

For the Commission, by the Division of Market Regulation, pursuant to delegated authority.[7]

**Florence E. Harmon,**

*Deputy Secretary.*

[FR Doc. E7–14037 Filed 7–19–07; 8:45 am]

**BILLING CODE 8010–01–P**

[5] 15 U.S.C. 78f(b).

[6] 6 15 U.S.C. 78f(b)(5).

[7] 17 CFR 200.30–3(a)(12).

**SECURITIES AND EXCHANGE COMMISSION**

**[Release No. 34–56068; File No. SR–NASDAQ–2007–062]**

**Self-Regulatory Organizations; The NASDAQ Stock Market LLC; Notice of Filing and Immediate Effectiveness of Proposed Rule Change To Exclude Partial Trading Days From the Calculation of a Member's Average Daily Volume**

July 13, 2007.

Pursuant to section 19(b)(1) of the Securities Exchange Act of 1934 (''Act'')[1] and Rule 19b–4 thereunder,[2] notice is hereby given that on June 21, 2007, The NASDAQ Stock Market LLC (''Nasdaq'') filed with the Securities and Exchange Commission (''Commission'') the proposed rule change as described in Items I, II, and III below, which Items have been substantially prepared by Nasdaq. Nasdaq has filed the proposal pursuant to section 19(b)(3)(A) of the Act[3] and Rule 19b–4(f)(2) thereunder,[4] which renders the proposal effective upon filing with 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**

Nasdaq proposes to exclude partial trading days from the calculation of a member's average daily volume. The text of the proposed rule change is available at Nasdaq, the Commission's Public Reference Room, and *http://www.nasdaq.com*.

**II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change**

In its filing with the Commission, Nasdaq included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. Nasdaq has prepared summaries, set forth in sections A, B, and C below, of the most significant aspects of such statements.

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] 15 U.S.C. 78s(b)(3)(A).

[4] 17 CFR 240.19b–4(f)(2).

*A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change*

1. Purpose

Nasdaq proposes to modify the manner in which a member's average daily volume is determined by excluding from the calculation days when the market is not open for the entire trading day. An example of such a partial trading day is Tuesday, July 3, 2007. On that day Nasdaq will cease trading at 1 p.m. Eastern Time (''ET'') [5] and, thus, trading for that day will be excluded from the calculation of a member's average daily volume. The change will ensure that members close to achieving the average daily volume required for a particular pricing level will not find it more difficult to achieve that level simply because a month contains a partial trading day.

2. Statutory Basis

Nasdaq believes that the proposed rule change is consistent with the provisions of section 6 of the Act,[6] in general, and with sections 6(b)(4) of the Act,[7] in particular, in that the proposal provides for the equitable allocation of reasonable dues, fees, and other charges among its members and issuers and other persons using any facility or system which Nasdaq operates or controls. Nasdaq believes that the change is reasonable because it will facilitate members achieving volume levels required for particular pricing levels in months with partial trading days.

*B. Self-Regulatory Organization's Statement on Burden on Competition*

Nasdaq does not believe that the proposed rule change will result in any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act.

*C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants or Others*

Written comments were neither solicited nor received.

[5] Although Nasdaq will officially ''close'' at 1 p.m. ET, Nasdaq will continue trading in an after hours session until 5 p.m. ET; compared to ''full trading days'' times of 4 p.m. ET and 8 p.m. ET, respectively.

[6] 15 U.S.C. 78f.

[7] 15 U.S.C. 78f(b)(4).

**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 [8] and subparagraph (f)(2) of Rule 19b–4 thereunder [9] because it establishes or changes a due, fee, or other charge applicable only to a member imposed by the self-regulatory organization. Accordingly, the proposal is effective upon Commission receipt of the filing. At any time within 60 days of the filing of the proposed rule change, the Commission may summarily abrogate such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act.

**IV. Solicitation of Comments**

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

*Electronic Comments*

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send an e-mail to *rule-comments@sec.gov.* Please include File Number SR–NASDAQ–2007–062 on the subject line.

*Paper Comments*

- Send paper comments in triplicate to Nancy M. Morris, Secretary, Securities and Exchange Commission, 100 F Street, NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–NASDAQ–2007–062. This file number should be included on the subject line if e-mail is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for inspection and copying in the Commission's Public Reference Room, 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 Nasdaq. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–NASDAQ–2007–062 and should be submitted on or August 10, 2007.

[8] 15 U.S.C. 78s(b)(3)(A)(ii).

[9] 17 CFR 240.19b–4(f)(2).

For the Commission, by the Division of Market Regulation, pursuant to delegated authority.[10]

**Florence E. Harmon,**

*Deputy Secretary.*

[FR Doc. E7–14055 Filed 7–19–07; 8:45 am]

BILLING CODE 8010–01–P

## SECURITIES AND EXCHANGE COMMISSION

**[Release No. 34–56072; File No. SR–NYSEArca–2007–61]**

## Self-Regulatory Organizations; NYSE Arca, Inc.; Notice of Filing and Immediate Effectiveness of Proposed Rule Change Adding a New Order Type Known As the Mid-Point Passive Liquidity Order

July 13, 2007.

Pursuant to section 19(b)(1) of the Securities Exchange Act of 1934 (''Act'') [1] and Rule 19b–4 thereunder,[2] notice is hereby given that on June 29, 2007, NYSE Arca, Inc. (''NYSE Arca'' or ''Exchange''), through its wholly-owned subsidiary, NYSE Arca Equities, Inc. (''NYSE Arca Equities'' or ''Corporation'') filed with the Securities and Exchange Commission (''Commission'') the proposed rule change as described in Items I and II below, which Items have been substantially prepared by the Exchange. The Exchange filed the proposed rule change pursuant to section 19(b)(3)(A) of the Act [3] and Rule 19b–4(f)(6) thereunder, which renders it effective upon filing with the Commission.[4] The Commission is publishing this notice to

[10] 17 CFR 200.30–3(a)(12).

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] 15 U.S.C. 78s(b)(3)(A).

[4] 17 CFR 240.19b–4(f)(6).

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, through its wholly-owned subsidiary, NYSE Arca Equities proposes to amend its rules in order to add a new order type known as the Mid-Point Passive Liquidity Order (''MPL Order''). The changes described in this rule proposal would add new NYSE Arca Equities Rule 7.31(h)(5) and would amend existing Rule 7.37(d)(2). The text of the proposed rule change is available at the Exchange, the Commission's Public Reference Room, and *http://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 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 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

As part of its continuing efforts to provide additional flexibility and increased functionality to its system and its Users,[5] the Exchange proposes to add a new order type known as the MPL Order. The MPL Order is a version of the NYSE Arca Passive Liquidity Order,[6] except that it will be executable only at the midpoint of the Protected Best Bid and Offer (''PBBO'').[7]

MPL Order Execution in NYSE Arca

The MPL Order will follow the same execution priority rules as the Passive Liquidity Order.[8] MPL Orders always execute at the midpoint of the PBBO and do not receive price improvement.

MPL Orders will be ranked in time priority for the purposes of execution as long as the midpoint is within the limit range of the order. The Exchange may set a minimum entry size for MPL Orders from time to time, with the initial minimum entry size set at 1,000 shares. Users may specify a minimum executable size for an MPL Order, but no less than 1,000 shares. An MPL Order with a specified minimum executable size will execute against an incoming order that meets the minimum executable size and is priced at or better than the midpoint of the PBBO.[9]

An MPL Order may be executed in subpennies if necessary to attain a midpoint price. Users may mark incoming limit orders with a ''No Midpoint Execution'' designator; so marked, those limit orders will ignore MPL Orders and trade against the rest of the book in the ordinary course.

MPL Orders will not be exclusive to Lead Market Makers[10] (''LMMs'') where NYSE Arca is the primary listings market. MPL Orders will be valid for any session but will not participate in any auctions. If the market is locked, the eligible MPL Order will trade at the locked price. If the market is crossed, the MPL Order will wait for the market to uncross before becoming eligible to trade again. MPL Orders will interact with all order types including contra MPL Orders, with the exception of cross orders.

MPL Orders will not route out of NYSE Arca to other market centers. For purposes of the NYSE Arca rules related to Regulation NMS, MPL Orders will never be routed to Protected or Manual Quotations. An MPL Order will not trade-through a Protected Quotation.

The Exchange believes that the implementation of the aforementioned rule changes adding a new order type and the related NYSE Arca order processing modifications will enhance order execution opportunities on NYSE Arca.[11] The Exchange believes that the proposed order type will allow for additional opportunities for liquidity providers, especially institutions, to passively interact with interest in the NYSE Arca book.

2. Statutory Basis

The Exchange believes that the proposed rule change is consistent with section 6(b) of the Act[12] in general, and furthers the objectives of section 6(b)(5) of the Act[13] in particular, because it is designed to prevent fraudulent and manipulative acts and practices, to promote just and equitable principles of trade, to foster cooperation and coordination with persons engaged in facilitating transactions in securities, and to remove impediments to and perfect the mechanism of a free and open market and a national market system.

*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*

The Exchange has neither solicited nor received written comments on the proposed rule change.

**III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action**

Because the foregoing proposed rule change does not: (i) Significantly affect the protection of investors or the public interest; (ii) impose any significant burden on competition; and (iii) become operative for 30 days from the date on which it was filed, or such shorter time as the Commission may designate, it has become effective pursuant to section 19(b)(3)(A)[14] of the Act and Rule 19b–4(f)(6) thereunder.[15] At any time within 60 days of the filing of the proposed rule change, the Commission may summarily abrogate such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act.

NYSE Arca has asked the Commission to waive the 30-day operative delay. The Commission believes such a waiver is consistent with the protection of investors and the public interest because it would permit the Exchange to codify the proposed order type, the MPL without delay.[16] For this reason, the Commission designates the proposal to

---

[5] *See* NYSE Arca Equities Rule 1.1(yy) for the definition of ''User.''

[6] *See* NYSE Arca Equities Rule 7.31(h)(4).

[7] *See* NYSE Arca Equities Rule 1.1(eee) for the definitions of ''Protected Bid'' and Protected Offer.''

[8] *See* NYSE Arca Equities Rule 7.31(h)(4) and 7.37(b)(2)(A)(iv).

[9] For example, an order may be entered to buy 10,000 MPL with a minimum size of 2,000. This would allow for execution of the MPL order only if the contra size order were at least 2,000 shares. If the leaves quantity becomes less than the minimum size, the minimum size restriction will no longer be enforced on executions.

[10] *See* NYSE Arca Equities Rule 1.1(ccc) for definition of ''Lead Market Makers.''

[11] This proposed order type is similar to the MidPoint Match mechanism of the International Securities Exchange, Inc. (''ISE''), previously approved by the Commission. *See* Securities Exchange Act Release No. 54528 (September 28, 2006), 71 FR 58650 (October 4, 2006) (SR–ISE–2006–48).

[12] 15 U.S.C. 78f(b).

[13] 15 U.S.C. 78f(b)(5).

[14] 15 U.S.C. 78s(b)(3)(A).

[15] 17 CFR 240.19b–4(f)(6).

[16] For purposes only of waiving the 30-day pre-operative period, the Commission has considered the proposed rule's impact on efficiency, competition and capital formation. 15 U.S.C. 78c(f).

be operative upon filing with the Commission.

## IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

*Electronic Comments*

- Use the Commission's Internet comment form: (*http://www.sec.gov/rules/sro.shtml*); or
- Send an e-mail to: *rule-comments@sec.gov*. Please include File Number SR–NYSEArca–2007–61 on the subject line.

*Paper Comments*

- Send paper comments in triplicate to Nancy M. Morris, Secretary, Securities and Exchange Commission, 100 F Street, NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–NYSEArca–2007–61. This file number should be included on the subject line if e-mail is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for inspection and copying in the Commission's Public Reference Room, 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 NYSE Arca. 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–2007–61 and should be submitted on or before August 10, 2007.

For the Commission, by the Division of Market Regulation, pursuant to delegated authority.[17]

**Florence E. Harmon,**

*Deputy Secretary.*

[FR Doc. E7–14036 Filed 7–19–07; 8:45 am]

**BILLING CODE 8010–01–P**

---

## SECURITIES AND EXCHANGE COMMISSION

**[Release No. 34–56069; File No. SR–OCC–2006–19]**

## Self-Regulatory Organizations; The Options Clearing Corporation; Order Granting Approval of a Proposed Rule Change Relating to Close-Out Netting Procedures

July 13, 2007.

### I. Introduction

On October 10, 2006, The Options Clearing Corporation ("OCC") filed with the Securities and Exchange Commission ("Commission") proposed rule change SR–OCC–2006–19 pursuant to section 19(b)(1) of the Securities Exchange Act of 1934 ("Act").[1] On May 15, 2007, OCC amended the proposed rule change. Notice of the proposal was published in the **Federal Register** on May 29, 2007.[2] On June 21, 2007, OCC again amended the proposed rule change.[3] Three comment letters were received.[4] For the reasons discussed below, the Commission is granting approval of the proposed rule change.

### II. Description

*Background*

OCC was asked by several of its Clearing Members to consider adopting a rule that would allow for close-out netting of obligations running between OCC and Clearing Members in the event of an OCC default or insolvency. The reason was that such a rule could reduce applicable capital requirements for a Clearing Member's parent company where the parent is a U.S. or non-U.S. bank or part of a Consolidated Supervised Entity ("CSE"). The absence of a netting agreement that would apply in a default or insolvency of OCC could cause the minimum capital requirement applicable to such a parent company and its subsidiaries to be substantially larger on a consolidated basis than it would be otherwise. In the absence of a netting agreement, applicable banking regulations generally prohibit offsetting the Clearing Member's liabilities to OCC on short positions in options and on other obligations against the Clearing Member's credits from OCC with respect to long options positions and from other obligations of OCC. In addition, OCC believes that a close-out netting rule would clarify the accounting treatment of obligations between OCC and its Clearing Members.

The proposed rule change is designed to allow Clearing Members to comply with international standards under the Basel Capital Accord adopted by the Basel Committee on Banking Supervision relating to bilateral netting ("Basel Netting Standards").[5] It is OCC's understanding that the capital rules applicable to most banks following the Basel Netting Standards require that an enforceable netting agreement be in place in order for mutual obligations between a Clearing Member that is a bank affiliate and a counterparty such as OCC to be treated on a net basis. The policy behind this requirement is to ensure that obligations that are treated on a net basis for capital purposes can actually be offset against one another in the event of the failure of the counterparty. In the absence of an enforceable netting agreement, there is concern that the representative of the failed counterparty (*i.e.*, OCC in this scenario) under applicable insolvency law might be able to "cherry pick" by assuming the benefit of contracts representing an asset to the bankruptcy estate while rejecting contracts representing a liability. This would force the non-defaulting counterparty (*i.e.*, the Clearing Member in this scenario) to perform in full on its liabilities while sharing with other unsecured creditors in any amounts available for distribution from the bankruptcy estate to satisfy its claims. An enforceable netting agreement providing for "close-out netting" in the event of a default or insolvency of OCC would avoid this potential result.

Chapter XI of OCC's Rules, Suspension of a Clearing Member, provides in considerable detail for

[17] 17 CFR 200.30–3(a)(12).

[1] 15 U.S.C. 78s(b)(1).

[2] Securities Exchange Act Release No. 55788 (May 21, 2007), 72 FR 29569.

[3] Although the proposed rule change was amended after it was noticed for comment in the **Federal Register**, republication of the notice was not necessary because the June 21, 2007, amendment made only a technical change regarding the application of a financial accounting interpretation.

[4] Edward S. Grieb, Managing Director and Financial Controller, Lehman Brothers Holdings Inc. (June 19, 2007); Matthew Schroeder, Chairman, Dealer Accounting Committee, Securities Industry and Financial Markets Association (June 19, 2007); Gregory A. Sigrist, Managing Director, Morgan Stanley, New York, New York (June 19, 2007).

[5] For more information on the Basel Committee on Banking Supervision and the Basel Netting Standards, see the Bank for International Settlement's Web site at: *http://www.bis.org.*

liquidation of the accounts of an insolvent Clearing Member including provisions for close-out netting of the Clearing Member's obligations against its assets to the extent permitted by customer protection rules under the Act and under the Commodity Exchange Act (''CEA''). However, OCC's rules do not presently contain any provisions that specifically provide for close-out netting in the event of a default or insolvency of OCC. Indeed, an OCC default or insolvency has always been considered so unlikely that OCC's rules do not contain any provisions whatever contemplating such events. OCC's management does not believe that an OCC default or insolvency has become any more likely. On the contrary, OCC's long history of safe operations and continually improved methods of risk management suggest that such an event is more remote than ever. Nevertheless, the Basel Netting Standards make it desirable for OCC to put in place such a netting provision in order to clarify the capital requirements applicable on a consolidated basis to parent companies of Clearing Members that are subject to the Basel Netting Standards.

The Basel Netting Standards are not directly applicable to the determination of net capital requirements for broker-dealers under Commission Rule 15c3–1.[6] However, some Clearing Members are subsidiaries of banks or bank holding companies that are subject to the Basel Netting Standards when computing capital requirements on a consolidated basis. In addition, several of OCC's largest Clearing Members have volunteered to participate in the Commission's CSE program. Finally, as noted below, OCC believes that a close-out netting rule would also clarify the accounting treatment of obligations between OCC and a Clearing Member under FIN 39.[7]

The Basel Netting Standards and FIN 39 (collectively ''Netting Standards'') are stated in general terms and do not contain detailed requirements. OCC's proposed close-out netting procedures would clearly permit Clearing Members to treat their obligations to OCC on a net basis to the fullest extent consistent with the Commission's customer protection rules in the event of an OCC default or insolvency. The proposed rule change is also intended to protect the clearing system from being thrown out of balance or forced into a disorderly liquidation by a single Clearing Member's exercise of netting rights. Unlike typical, purely bilateral OTC derivatives relationships, OCC's contractual rights and obligations, while bilateral between OCC and any individual Clearing Member, represent a balanced structure in which every obligation owed by OCC to a Clearing Member is in turn matched by a corresponding obligation of a Clearing Member to OCC. The creation of individually exercisable netting rights that could be exercised independently by each Clearing Member in the event of an OCC default or insolvency could result in unfairness and disruption if no coordination is imposed.

*The Basel Netting Standards*

The Basel Netting Standards are contained in Basel II: International Convergence of Capital Measurement and Capital Standards: A Revised Framework—Comprehensive Version (June 2006) (''Basel II Accord''). The Basel Netting Standards provide that a bank [8] may net transactions subject to any legally valid form of bilateral netting, including netting of bilateral obligations arising from novation, if the bank satisfies its national supervisor that it has a netting contract with the counterparty ''which creates a single legal obligation, covering all included transactions, such that the bank would have either a claim to receive or obligation to pay only the net sum of the positive and negative mark-to-market values of included individual transactions in the event a counterparty fails to perform due to any * * * default, bankruptcy, liquidation or similar circumstances.'' [9]

The Basel Netting Standards also require that the bank have certain ''written and reasoned legal opinions that, in the event of a legal challenge, the relevant courts and administrative authorities would find the bank's exposure to be the net amount.'' The national supervisor must be satisfied that the netting is enforceable under the laws of each relevant jurisdiction. The proposed close-out netting procedures are intended to support such an opinion.

The Basel Netting Standards have been incorporated in applicable bank regulatory laws or regulations in various jurisdictions. For example, the substance of this standard appears in Article 12f of the Swiss Banking Ordinance. It has also been incorporated into the capital guidelines for various U.S. financial institutions.[10]

*FDICIA and Bankruptcy Code*

The proposed close-out netting procedures are designed to take advantage of the netting provisions of Title IV of the Federal Deposit Insurance Corporation Improvement Act of 1991 (''FDICIA'') and of the applicable provisions of the United States Bankruptcy Code. Section 404 of FDICIA generally validates netting contracts among members of clearing organizations notwithstanding any other provision of law.[11] In order to qualify for this benefit, the ''netting contract'' must be between ''members'' of a ''clearing organization,'' as each of these terms is defined in FDICIA. OCC meets the definition of ''clearing organization'' under FDICIA, and both it and its Clearing Members meet the definition of ''members.'' Under FDICIA, the rules of a clearing organization are expressly included within the definition of ''netting contract.'' Accordingly, under section 404 of FDICIA, the netting provisions of OCC's By-Laws and Rules, including the proposed revised netting procedures, will be given effect in the event of OCC's default or insolvency.

Section 362(b) of the United States Bankruptcy Code [12] exempts from the automatic stay provisions of the Bankruptcy Code the setoff by, among other parties, stockbrokers, commodity brokers, or clearing agencies of mutual debts or claims under commodity or securities contracts. This section preserves OCC's ability to net obligations between OCC and a suspended Clearing Member and similarly would protect the ability of Clearing Members to net obligations under the proposed netting procedures in the event of OCC's default or insolvency. In addition, the Bankruptcy Abuse Prevention and Consumer Protection Act of 2005 (''BAPCPA'') [13] added to the Bankruptcy Code new subsection 362(o) which provides that the right of setoff and other relevant rights may not be stayed by any order of a court or administrative agency in any proceeding under the Bankruptcy Code.[14] This addition was a significant expansion of the protections for

[6] 17 CFR 240.15c3–1.

[7] Financial Account Standards Board (''FASB'') Interpretation No. 39, Offsetting of Amounts Related to Certain Contracts. FIN 39 specifies the circumstances in which assets and liabilities may be treated as offsetting in financial statements.

[8] These same standards are also applied to bank holding companies.

[9] Basel Committee on Banking Supervision, Basel Capital Accord: Treatment of Potential Exposure for Off-Balance Sheet Items (April 1995) at Annex, p. 4. The relevant bilateral netting standards under this 1995 publication were not overridden by the Basel II Accord. Basel II Accord at p. 213. Basel II also allows cross-product netting.

[10] *See e.g.*, Regulations of the Office of the Comptroller of the Currency applicable to national banks set forth at 12 CFR appendix A to part 3 section (3)(b)(5)(ii)(B) (adopted July 1, 2002).

[11] 12 U.S.C. 4403.

[12] 11 U.S.C. 362(b).

[13] Public Law 109–8, 119 Stat. 23 (2005).

[14] 11 U.S.C. 362(o).

financial contracts under the Bankruptcy Code.

*Prior Netting Filing and Clearing Member Comments*

OCC previously submitted and subsequently withdrew a proposed rule change with respect to close-out netting (''Prior Netting Filing'').[15] After reviewing the Prior Netting Filing, some Clearing Members questioned whether the netting procedures set forth in that filing satisfied the Netting Standards. Specifically, Clearing Members questioned whether:

1. The definition of insolvency in the Prior Netting Filing, which covered only voluntary or involuntary cases under Chapter 7, needed to be expanded to include other types of bankruptcies, particularly Chapter 11 cases, and non-bankruptcy defaults;

2. The procedures set forth in the Prior Netting Filing complied with the Netting Standards in light of the inability of the Clearing Members as the non-defaulting parties to initiate the netting process; and

3. The proposed procedures gave Clearing Members the ability to promptly net and to close-out positions as required to comply with the Netting Standards given the degree of control that OCC reserved to itself in the process.

After considering the Clearing Members' comments, OCC withdrew the Prior Netting Filing and made modifications to the proposed netting provisions which are reflected in the current filing. The primary differences between the currently-proposed close-out netting procedures and those contained in the Prior Netting Filing are that the currently-proposed procedures:

1. Significantly expand the definition of insolvency to include non-bankruptcy defaults, specifically any failure by OCC to comply with an undisputed obligation to deliver money or property to a Clearing Member for a period of thirty days after the obligation becomes due, and to include bankruptcy or insolvency proceedings under statutory provisions other than Chapter 11 of the U.S. Bankruptcy Code;

2. Provide that upon the occurrence of an event of default or insolvency, any Clearing Member that is neither suspended nor in default with regard to an obligation to OCC may provide a notice to OCC of its intention to terminate all cleared contracts and stock loan and borrow positions in all of its accounts; and

3. Establish a fixed termination time for all cleared contracts and stock loan and borrow positions, which would be the close of business on the third business day after OCC's receipt of the prescribed notice from a Clearing Member unless a different time is mandated by the Bankruptcy Code, and provide that the liquidation settlement date will occur as promptly as practicable after the termination time (the original provisions granted OCC the discretion to establish the termination time and provided that the liquidation settlement date would occur no earlier than the business day following the termination date).

OCC believes that the above modifications address the Clearing Members' concerns while still permitting the liquidation process to proceed in an orderly manner and the clearance system to remain in balance.

*Overview of Proposed Rule Change*

The proposed rule change consists of a single new Section 27, Close-Out Netting, of Article VI of OCC's By-Laws, Clearance of Exchange Transactions. Consistent with the requirements of the Basel Netting Standards, the netting provision is applicable in the event that OCC fails to perform its obligations with respect to cleared contracts as the result of defaults by OCC in performing its obligations under its rules or as the result of bankruptcy, a liquidation of OCC, or similar circumstances. The close-out netting procedures are drafted in such a way that they would only be triggered by an event of default, as defined in new section 27(a). The procedures would not be triggered by any delay in performance that is permitted under OCC's By-Laws or Rules. For example, section 19 of Article VI of OCC's By-Laws permits OCC to take specified actions, including suspension of settlement obligations, in the event of a shortage of underlying securities. These delays would not be considered an event of default under section 27 and therefore would not allow a Clearing Member to initiate the close-out netting procedures.

Under the proposed close-out netting procedures, in the event of a default or insolvency by OCC, OCC would be required to provide notice of the default or insolvency to the Commission, the CFTC, all Clearing Members, any clearing organizations with which OCC has cross-margining or cross-guarantee agreements, and all markets for which OCC clears transactions. The proposed procedures further provide that in the event of an OCC default, any Clearing Member, so long as it is not suspended or in default, may provide a written notice to OCC of its intent to initiate the liquidation process with regard to its own contracts and stock loan and borrow positions. This notice would, however, trigger a liquidation of cleared contracts and positions of all Clearing Members. This procedure is necessary because liquidating contracts and positions of less than all Clearing Members would result in an imbalance of the clearing system and therefore would be unworkable. The proposed procedures establish the close of business on the third business day after OCC's receipt of the liquidation notice from a Clearing Member as the termination time unless the Bankruptcy Code prescribes a different time.

The proposed close-out netting procedures provide that when a triggering event occurs, rights and obligations within and between accounts of each Clearing Member will be netted to the same extent as if the Clearing Member had been suspended and its accounts were being liquidated under Chapter XI of the Rules. This is appropriate in that those rules generally provide for the netting of assets against liabilities to the extent permitted under applicable law, including the customer protection rules referred to above. Assets remaining after all legally permissible offsets would be returned to the Clearing Member entitled to them. The Clearing Member would remain obligated to OCC only to the extent of any remaining net liabilities following such permitted offsets.

If close-out netting were ever required because of the default or insolvency of OCC, it seems likely that there would be no market available in which to liquidate positions in cleared contracts through market transactions. Accordingly, the proposed procedures contain a provision for valuation of open cleared contracts based upon market values of underlying interests and provide a reasonable means for OCC to fix all necessary values of assets and liabilities for purposes of the netting. Under the procedures, OCC is to provide valuations as promptly as practicable but in any event within thirty days of the termination time. Valuations would be based upon available market information.

*FIN 39: Offsetting of Amounts Related to Certain Contracts*

In addition to the potential benefit of the proposed close-out netting procedures with respect to capital requirements applicable to certain Clearing Members and their affiliates on a consolidated basis under the Basel Netting Standards, OCC believes that the proposed close-out netting procedures should also clarify the accounting treatment of mutual

[15] File No. SR–OCC–2005–17.

obligations running between OCC and its Clearing Members. OCC's Clearing Members most commonly prepare their financial statements using United States Generally Accepted Accounting Principles (''US GAAP''). FIN 39 responds to certain questions relating to the circumstances in which assets and liabilities may be treated as offsetting in financial statements. FIN 39 is an interpretation of Accounting Principles Board (''APB'') Opinion No. 10, which states that ''it is a general principle of accounting that the offsetting of assets and liabilities in the balance sheet is improper except where a right of setoff exists.'' FIN 39 provides a definition of a right of setoff and a statement of the conditions under which a right of setoff exists. FIN 39 states, ''A right of setoff is a debtor's legal right, by contract or otherwise, to discharge all or a portion of the debt owed to another party by applying against the debt an amount that the other party owes to the debtor.'' FIN 39 sets forth the following four conditions which must be met for there to exist a right of setoff:

(1) Each of two parties owes the other determinable amounts.

(2) The reporting party has the right to set off the amount owed with the amount owed by the other party.

(3) The reporting party intends to set off.

(4) The right of setoff is enforceable at law.

It is the obligation of each Clearing Members to determine its proper application of U.S. GAAP but OCC believes that proposed new section 27 will enable Clearing Members to conclude that conditions (1), (2), and (4) have been met. (Condition (3) deals with intent, which is a factual question.)

*Discussion of Specific Provisions of Section 27*

The text of proposed new section 27 of Article VI of the By-Laws is largely self-explanatory in light of the foregoing discussion of its purpose. A few comments may nevertheless be helpful.

Under proposed sections 27(a) and (b), if OCC should ever give notice of its default or insolvency and a Clearing Member in turn provide a notice of termination, the termination time may be later than the time at which a Clearing Member's liquidation notice is given.[16] This leaves open at least the theoretical possibility that, if there are trading days or hours left between the time the notice is given and the termination time, market participants could attempt to engage in closing transactions at prices determined in the market to avoid being subject to a forced liquidation at prices fixed by OCC.[17]

Proposed section 27(b) provides that in the event of a default or insolvency and the requisite notice by a Clearing Member, positions of all Clearing Members will be liquidated to the maximum extent permitted by law and the By-Laws and Rules. The limitations on netting under OCC's By-Laws and Rules are in general those mandated by applicable law, such as the Commission's Rule 15c3–3. For example, where a Clearing Member carries both proprietary and customer accounts netting across accounts could cause the Clearing Member to be in violation of Rule 15c3–3 and other customer protection rules. Accordingly, section 27 generally provides for netting within and not across different accounts with specific exceptions set forth in section 27(d). In addition, CEA segregation rules require separate segregation of customer funds of futures customers. Accordingly, netting across futures segregated funds accounts and other accounts is also generally prohibited. Otherwise, the provisions of section 27(d) are intended to maximize netting where consistent with customer protection rules. While securities market-makers and specialists are generally not customers within the meaning of Rule 15c3–3, they are ordinarily ''customers'' within the meaning of the Commission's hypothecation rules.[18] OCC has historically not permitted setoff between market-maker accounts and customer accounts in which positions of other securities customers are carried. This separation has been preserved in section 27(d)(3).

## III. Comments

The Commission received three comment letters to the proposed rule change.[19] All three comment letters support the proposed rule change. Two of the comment letters, one from the Dealer Accounting Committee of the Securities Industry and Financial Markets Association and one from Lehman Brothers Holdings, Inc., state that the commenters support the proposed rule change because it is designed to allow OCC's members to comply with the Basel Capital Accord standards relating to bilateral netting and because it will clarify the accounting treatment of obligations between OCC and its clearing members. The third comment letter, from Morgan Stanley, states that Morgan Stanley believes the proposed rule change would result in significant improvement in financial reporting, would better align financial reporting with risk management practices, and would result in presenting the net credit risk exposure related to derivative instruments cleared through the OCC.

## IV. Discussion

Section 17A(b)(3)(F) of the Act requires, among other things, that the rules of a clearing agency be designed to remove impediments to and perfect the mechanism of a national system for the prompt and accurate clearance and settlement of securities transactions.[20] The proposed rule change should help to reduce uncertainty by establishing the procedures OCC and its Clearing Members must follow in the event of an OCC default or insolvency. Accordingly, because the proposed rule change establishes procedures that should reduce uncertainty and streamline the final clearance and settlement process in the event OCC defaults on it obligations to its members or otherwise becomes insolvent, we find that the proposed rule change is designed to remove impediments to and perfect the mechanism of a national system for the prompt and accurate clearance and settlement of securities transactions.

Although the proposed rule change applies in the event of the default or insolvency of OCC, OCC considers such an event to be unlikely. OCC's purpose in making the rule change is to allow its Clearing Members and certain affiliates of its Clearing Members to obtain better treatment under regulatory and financial standards where such better treatment requires that close-out netting procedures are in place. The close-out netting procedures are intended to allow Clearing Members to (1) reduce the applicable capital requirements for the Clearing Member's parent company where the parent is a U.S. or non-U.S. bank or part of a CSE under the Basel Netting Standards; (2) take advantage of the netting provisions of FDICIA and the applicable provisions of the United States Bankruptcy Code; and (3) clarify the accounting treatment of obligations

[16] Under proposed section 27(b), the termination time would be the close of business on the third business day following a Clearing Member's liquidation notice unless the Bankruptcy Code prescribes a different time. Under section 502(b) of the Bankruptcy Code, claims against a debtor are valued as of the date of the filing of the bankruptcy petition. Accordingly, in the event of a bankruptcy the termination time would be on the date of the filing of the petition.

[17] 17 Such activity of market participants could start at the time of OCC's default notice rather than the time of the liquidation notice although as a practical matter a liquidation notice would likely closely follow the default notice.

[18] 17 CFR 240.8c–1 and 240.15c2–1.

[19] *Supra* note 4.

[20] 5 U.S.C. 78q–1(b)(3)(F).

between OCC and each Clearing Member under FIN 39. While the Commission believes that these intended benefits of the proposed rule change are not inconsistent with our finding above that the proposed rule change is designed to remove impediments to and perfect the mechanism of a national system for the prompt and accurate clearance and settlement of securities transactions under section 17A the Act, we note that this order relates only to OCC's obligations under section 17A of the Act and neither makes any findings nor expresses any opinion with respect to OCC's representations and interpretations regarding the application of the Basel Netting Standards, FDCIA, Bankruptcy Code, or FIN 39.

**V. Conclusion**

On the basis of the foregoing, the Commission finds that the proposed rule change is consistent with the requirements of the Act and in particular section 17A of the Act and the rules and regulations thereunder.[21]

*It is therefore ordered*, pursuant to section 19(b)(2) of the Act, that the proposed rule change (File No. SR–OCC–2006–19) be and hereby is approved.

For the Commission by the Division of Market Regulation, pursuant to delegated authority.[22]

**Florence E. Harmon,**

*Deputy Secretary.*

[FR Doc. E7–14019 Filed 7–19–07; 8:45 am]

**BILLING CODE 8010–01–P**

---

## SECURITIES AND EXCHANGE COMMISSION

**[Release No. 34–56076; File No. SR–Phlx–2007–46]**

## Self-Regulatory Organizations; Philadelphia Stock Exchange, Inc.; Notice of Filing and Immediate Effectiveness of Proposed Rule Change Relating to Priority of Synthetic Option Orders in Open Outcry

July 16, 2007.

Pursuant to section 19(b)(1) of the Securities Exchange Act of 1934 (''Act''),[1] and Rule 19b–4 thereunder,[2] notice is hereby given that on June 26, 2007, the Philadelphia Stock Exchange, Inc. (''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 substantially prepared by the Phlx. The Exchange filed the proposed rule change pursuant to section 19(b)(3)(A) of the Act[3] and Rule 19b–4(f)(6) thereunder,[4] which renders the proposal effective upon filing with 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 Phlx proposes to adopt, on a permanent basis, Exchange Rule 1033(e), which is currently subject to a pilot program (the ''pilot'') scheduled to expire June 30, 2007. Exchange Rule 1033(e) affords priority to synthetic option orders (as defined below) traded in open outcry over bids and offers in the trading crowd but not over bids (offers) of public customers on the limit order book and not over crowd participants who are willing to participate in the synthetic option order at the net debit or credit price. The rule applies to orders for 100 contracts or more. The Exchange proposes to adopt the rule on a permanent basis. The text of the proposed rule change is set forth below. Brackets indicate deletions; *italics* indicate new text.

Bids And Offers—Premium

Rule 1033. (a)–(d) No change.

(e) Synthetic Option Orders. When a member holding a synthetic option order, as defined in Rule 1066, and bidding or offering on the basis of a total credit or debit for the order has determined that the order may not be executed by a combination of transactions at or within the bids and offers established in the marketplace, then the order may be executed as a synthetic option order at the total credit or debit with one other member, provided that, the member executes the option leg at a better price than the established bid or offer for that option contract, in accordance with Rule 1014. [Subject to a pilot expiring June 30, 2007, s] *S*ynthetic option orders in open outcry, in which the option component is for a size of 100 contracts or more, have priority over bids (offers) of crowd participants who are bidding (offering) only for the option component of the synthetic option order, but not over bids (offers) of public customers on the limit order book, and not over crowd participants that are willing to participate in the synthetic option order at the net debit or credit price.

(f)–(i) No change.

**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 Phlx 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 Phlx 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 adopt, on a permanent basis, Exchange Rule 1033(e), which facilitates the execution of option orders that are represented in the crowd together with a stock component, known under the Exchange's rules as synthetic option orders,[5] which by virtue of the stock component may be difficult to execute without a limited exception to current Exchange priority rules. The pilot was originally adopted in July 2005,[6] extended for an additional six-month period through June 30, 2006,[7] and subsequently extended for one year, which is scheduled to expire June 30, 2007.[8]

---

[21] In approving the proposed rule change, the Commission considered the proposal's impact on efficiency, competition and capital formation. 15 U.S.C. 78c(f).

[22] 17 CFR 200.30–3(a)(12).

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] 15 U.S.C. 78s(b)(3)(A).

[4] 17 CFR 240.19b–4(f)(6).

[5] Exchange Rule 1066(g) currently defines a synthetic option order as an order to buy or sell a stated number of option contracts and buy or sell the underlying stock or Exchange-Traded Fund Share in an amount that would offset (on a one-for-one basis) the option position. For example:

(1) Buy-write: An example of a buy-write is an order to sell one call and buy 100 shares of the underlying stock or Exchange-Traded Fund Share.

(2) Synthetic put: An example of a synthetic put is an order to buy one call and sell 100 shares of the underlying stock or Exchange-Traded Fund Share.

(3) Synthetic call: An example of a synthetic call is an order to buy (or sell) one put and buy (or sell) 100 shares of the underlying stock or Exchange-Traded Fund Share.

[6] *See* Securities Exchange Act Release No. 52140 (July 27, 2005), 70 FR 45481 (August 5, 2005) (SR–Phlx–2005–31).

[7] *See* Securities Exchange Act Release No. 53004 (December 22, 2005), 70 FR 77234 (December 29, 2005) (SR–Phlx–2005–78).

[8] *See* Securities Exchange Act Release No. 54017 (June 19, 2006), 71 FR 36596 (June 27, 2006) (SR–Phlx–2006–38).

Currently, Exchange Rule 1033(e) provides that, if an Exchange member who is holding a synthetic option order and is bidding or offering on a net debit or credit basis determines that such synthetic option order cannot be executed at the net debit or credit against the established bids and offers in the crowd, the member bidding for or offering the synthetic option on a net debit or credit basis may execute the synthetic option order with one other crowd participant, provided that the option portion of the synthetic option order is executed at a price that is better than the established bid or offer for the option. Thus, if the desired net debit or credit amount cannot be achieved by way of executing against the established bids and offers in the crowd, the member may elect to trade at the desired net debit or credit amount with one other member, provided that there is price improvement for the option component of the synthetic option order.

Exchange Rule 1033(e) affords synthetic option orders priority over bids (offers) of the trading crowd but not over bids (offers) of public customers on the limit order book and not over crowd participants who are willing to participate in the synthetic option order at the net debit or credit price. The effect of the rule is that a crowd participant bidding or offering for the synthetic option order has priority over other crowd participants that are bidding or offering only for the option component of the order. The rule applies only to synthetic option orders of 100 contracts or more.

In addition, the rule provides that members bidding and offering for synthetic option orders of 100 contracts or more do not have priority over bids (offers) of public customers on the limit order book.[9] Therefore, if members of the trading crowd wish to trade a synthetic option order that is marketable against public customer orders on the limit order book, public customers would have priority. Multiple public customer orders at the same price are accorded priority based on time.

The Exchange believes that Exchange Rule 1033(e), which provides a limited exception to the Exchange's priority rules only with respect to controlled accounts [10] competing at the same price, should enable Floor Brokers representing synthetic option orders to provide best executions to customers placing such orders and should enable the Exchange to provide liquid markets and compete for order flow in such orders.

As stated above, the rule applies only to synthetic option orders in which the option component is for a size of 100 contracts or more that are represented in the trading crowd in open outcry.

2. Statutory Basis

The Exchange believes that its proposal is consistent with section 6(b) of the Act [11] in general and furthers the objectives of section 6(b)(5) of the Act [12] 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 adopting a limited exception to the Exchange's priority rules concerning synthetic option orders.

*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 from the date on which it was filed, or such shorter time as the Commission may designate if consistent with the protection of investors and the public interest, it has become effective pursuant to Section 19(b)(3)(A) of the Act [13] and Rule 19b–4(f)(6) thereunder.[14] At any time within 60 days of the filing of the proposed rule change, the Commission may summarily abrogate such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act.[15]

The Exchange requests that the Commission waive the 30-day operative period under Rule 19b–4(f)(6)(iii) [16] in order to ensure the continuity of the rule. The Commission believes that it is consistent with the protection of investors and the public interest to waive the 30-day operative delay.[17] The Commission believes that the waiver of the 30-day operative delay will allow the Exchange to continue, without interruption, the existing operation of its rule.

**IV. Solicitation of Comments**

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

*Electronic Comments*

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send an e-mail to: *rule-comments@sec.gov.* Please include File Number SR–Phlx–2007–46 on the subject line.

*Paper Comments*

- Send paper comments in triplicate to Nancy M. Morris, Secretary, Securities and Exchange Commission, 100 F Street, NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–Phlx–2007–46. This file number should be included on the subject line if e-mail is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written

[9] *See* Exchange Rule 1080, Commentary .02.

[10] A controlled account includes any account controlled by or under common control with a broker-dealer. Customer accounts are all other accounts. Orders of controlled accounts are required to yield priority to customer orders when competing at the same price. Orders of controlled accounts generally are not required to yield priority to other controlled account orders. *See* Exchange Rule 1014(g)(i)(A).

[11] 15 U.S.C. 78f(b).

[12] 15 U.S.C. 78f(b)(5).

[13] 15 U.S.C. 78s(b)(3)(A).

[14] 17 CFR 240.19b–4(f)(6).

[15] As required by Rule 19b–4(f)(6)(iii) under the Act, the Exchange provided the Commission with written notice of its intent to file the proposed rule change, along with a brief description of the text of the proposed rule change, at least five business days prior to the date of the filing of the proposed rule change.

[16] 17 CFR 240.19b–4(f)(6)(iii).

[17] For purposes only of waiving the 30-day operative delay of this proposal, the Commission has considered the proposed rule's impact on efficiency, competition, and capital formation. 15 U.S.C. 78c(f).

communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for inspection and copying in the Commission's Public Reference Room, 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 Phlx. 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–2007–46 and should be submitted on or beforeAugust 10, 2007.

For the Commission, by the Division of Market Regulation, pursuant to delegated authority.[18]

**Florence E. Harmon,**

*Deputy Secretary.*

[FR Doc. E7–14023 Filed 7–19–07; 8:45 am]

**BILLING CODE 8010–01–P**

## SECURITIES AND EXCHANGE COMMISSION

**[Release No. 34–56076; File No. SR–Phlx–2007–46]**

## Self-Regulatory Organizations; Philadelphia Stock Exchange, Inc.; Notice of Filing and Immediate Effectiveness of Proposed Rule Change Relating to Priority of Synthetic Option Orders in Open Outcry

July 16, 2007.

Pursuant to section 19(b)(1) of the Securities Exchange Act of 1934 (''Act''),[1] and Rule 19b–4 thereunder,[2] notice is hereby given that on June 26, 2007, the Philadelphia Stock Exchange, Inc. (''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 substantially prepared by the Phlx. The Exchange filed the proposed rule change pursuant to section 19(b)(3)(A) of the Act[3] and Rule 19b–4(f)(6) thereunder,[4] which renders the proposal effective upon filing with 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 Phlx proposes to adopt, on a permanent basis, Exchange Rule 1033(e), which is currently subject to a pilot program (the ''pilot'') scheduled to expire June 30, 2007. Exchange Rule 1033(e) affords priority to synthetic option orders (as defined below) traded in open outcry over bids and offers in the trading crowd but not over bids (offers) of public customers on the limit order book and not over crowd participants who are willing to participate in the synthetic option order at the net debit or credit price. The rule applies to orders for 100 contracts or more. The Exchange proposes to adopt the rule on a permanent basis. The text of the proposed rule change is set forth below. Brackets indicate deletions; *italics* indicate new text.

Bids and Offers—Premium

Rule 1033.(a)–(d) No change.

(e) Synthetic Option Orders. When a member holding a synthetic option order, as defined in Rule 1066, and bidding or offering on the basis of a total credit or debit for the order has determined that the order may not be executed by a combination of transactions at or within the bids and offers established in the marketplace, then the order may be executed as a synthetic option order at the total credit or debit with one other member, provided that, the member executes the option leg at a better price than the established bid or offer for that option contract, in accordance with Rule 1014. [Subject to a pilot expiring June 30, 2007, s] *S*ynthetic option orders in open outcry, in which the option component is for a size of 100 contracts or more, have priority over bids (offers) of crowd participants who are bidding (offering) only for the option component of the synthetic option order, but not over bids (offers) of public customers on the limit order book, and not over crowd participants that are willing to participate in the synthetic option order at the net debit or credit price.

(f)–(i) No change.

### 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 Phlx 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 Phlx 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 adopt, on a permanent basis, Exchange Rule 1033(e), which facilitates the execution of option orders that are represented in the crowd together with a stock component, known under the Exchange's rules as synthetic option orders,[5] which by virtue of the stock component may be difficult to execute without a limited exception to current Exchange priority rules. The pilot was originally adopted in July 2005,[6] extended for an additional six-month period through June 30, 2006,[7] and subsequently extended for one year, which is scheduled to expire June 30, 2007.[8]

Currently, Exchange Rule 1033(e) provides that, if an Exchange member who is holding a synthetic option order and is bidding or offering on a net debit or credit basis determines that such synthetic option order cannot be executed at the net debit or credit against the established bids and offers in the crowd, the member bidding for or offering the synthetic option on a net debit or credit basis may execute the synthetic option order with one other crowd participant, provided that the option portion of the synthetic option order is executed at a price that is better

[18] 17 CFR 200.30–3(a)(12).

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] 15 U.S.C. 78s(b)(3)(A).

[4] 17 CFR 240.19b–4(f)(6).

[5] Exchange Rule 1066(g) currently defines a synthetic option order as an order to buy or sell a stated number of option contracts and buy or sell the underlying stock or Exchange-Traded Fund Share in an amount that would offset (on a one-for-one basis) the option position. For example:

(1) Buy-write: An example of a buy-write is an order to sell one call and buy 100 shares of the underlying stock or Exchange-Traded Fund Share.

(2) Synthetic put: An example of a synthetic put is an order to buy one call and sell 100 shares of the underlying stock or Exchange-Traded Fund Share.

(3) Synthetic call: An example of a synthetic call is an order to buy (or sell) one put and buy (or sell) 100 shares of the underlying stock or Exchange-Traded Fund Share.

[6] *See* Securities Exchange Act Release No. 52140 (July 27, 2005), 70 FR 45481 (August 5, 2005) (SR–Phlx–2005–31).

[7] *See* Securities Exchange Act Release No. 53004 (December 22, 2005), 70 FR 77234 (December 29, 2005) (SR–Phlx–2005–78).

[8] *See* Securities Exchange Act Release No. 54017 (June 19, 2006), 71 FR 36596 (June 27, 2006) (SR–Phlx–2006–38).

than the established bid or offer for the option. Thus, if the desired net debit or credit amount cannot be achieved by way of executing against the established bids and offers in the crowd, the member may elect to trade at the desired net debit or credit amount with one other member, provided that there is price improvement for the option component of the synthetic option order.

Exchange Rule 1033(e) affords synthetic option orders priority over bids (offers) of the trading crowd but not over bids (offers) of public customers on the limit order book and not over crowd participants who are willing to participate in the synthetic option order at the net debit or credit price. The effect of the rule is that a crowd participant bidding or offering for the synthetic option order has priority over other crowd participants that are bidding or offering only for the option component of the order. The rule applies only to synthetic option orders of 100 contracts or more.

In addition, the rule provides that members bidding and offering for synthetic option orders of 100 contracts or more do not have priority over bids (offers) of public customers on the limit order book.[9] Therefore, if members of the trading crowd wish to trade a synthetic option order that is marketable against public customer orders on the limit order book, public customers would have priority. Multiple public customer orders at the same price are accorded priority based on time.

The Exchange believes that Exchange Rule 1033(e), which provides a limited exception to the Exchange's priority rules only with respect to controlled accounts [10] competing at the same price, should enable Floor Brokers representing synthetic option orders to provide best executions to customers placing such orders and should enable the Exchange to provide liquid markets and compete for order flow in such orders.

As stated above, the rule applies only to synthetic option orders in which the option component is for a size of 100 contracts or more that are represented in the trading crowd in open outcry.

2. Statutory Basis

The Exchange believes that its proposal is consistent with section 6(b) of the Act [11] in general and furthers the objectives of section 6(b)(5) of the Act [12] 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 adopting a limited exception to the Exchange's priority rules concerning synthetic option orders.

*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 from the date on which it was filed, or such shorter time as the Commission may designate if consistent with the protection of investors and the public interest, it has become effective pursuant to section 19(b)(3)(A) of the Act [13] and Rule 19b–4(f)(6) thereunder.[14] At any time within 60 days of the filing of the proposed rule change, the Commission may summarily abrogate such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act.[15]

The Exchange requests that the Commission waive the 30-day operative period under Rule 19b–4(f)(6)(iii) [16] in order to ensure the continuity of the rule. The Commission believes that it is consistent with the protection of investors and the public interest to waive the 30-day operative delay.[17] The Commission believes that the waiver of the 30-day operative delay will allow the Exchange to continue, without interruption, the existing operation of its rule.

**IV. Solicitation of Comments**

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

*Electronic Comments*

• Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or

• Send an e-mail to: *rule-comments@sec.gov.* Please include File Number SR–Phlx–2007–46 on the subject line.

*Paper Comments*

• Send paper comments in triplicate to Nancy M. Morris, Secretary, Securities and Exchange Commission, 100 F Street, NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–Phlx–2007–46. This file number should be included on the subject line if e-mail is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for inspection and copying in the Commission's Public Reference Room, 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 Phlx. All

[9] *See* Exchange Rule 1080, Commentary .02.

[10] A controlled account includes any account controlled by or under common control with a broker-dealer. Customer accounts are all other accounts. Orders of controlled accounts are required to yield priority to customer orders when competing at the same price. Orders of controlled accounts generally are not required to yield priority to other controlled account orders. *See* Exchange Rule 1014(g)(i)(A).

[11] 15 U.S.C. 78f(b).

[12] 15 U.S.C. 78f(b)(5).

[13] 15 U.S.C. 78s(b)(3)(A).

[14] 17 CFR 240.19b–4(f)(6).

[15] As required by Rule 19b–4(f)(6)(iii) under the Act, the Exchange provided the Commission with written notice of its intent to file the proposed rule change, along with a brief description of the text of the proposed rule change, at least five business days prior to the date of the filing of the proposed rule change.

[16] 17 CFR 240.19b–4(f)(6)(iii).

[17] For purposes only of waiving the 30-day operative delay of this proposal, the Commission has considered the proposed rule's impact on efficiency, competition, and capital formation. 15 U.S.C. 78c(f).

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–2007–46 and should be submitted on or before August 10, 2007.

For the Commission, by the Division of Market Regulation, pursuant to delegated authority.[18]

**Florence E. Harmon,**

*Deputy Secretary.*

[FR Doc. E7–14024 Filed 7–19–07; 8:45 am]

**BILLING CODE 8010–01–P**

[18] 17 CFR 200.30–3(a)(12).

## DEPARTMENT OF TRANSPORTATION

### Federal Aviation Administration

**[Docket No. FAA–2007–28041]**

### Notice of Availability and Public Comment Period for the Draft Air Quality General Conformity Determination (DGCD) for Proposed Operations of Lynx Aviation, Inc. at Denver International Airport, Denver, CO

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

**ACTION:** Notice of availability of the Draft Air Quality General Conformity Determination and notice of public comment period.

**SUMMARY:** The FAA is issuing this notice to advise the public that FAA has prepared a Draft Air Quality General Conformity Determination (DGCD) for Proposed Operations of Lynx Aviation, Inc. (Lynx Aviation) at Denver International Airport (DEN) and to request comments from the public on the DGCD. In accordance with Section 176(c) of the Clean Air Act, FAA has assessed whether the emissions that would result from FAA's action in approving the proposed operation specifications (OPSPECS) for Lynx Aviation's proposed operations at DEN conform to the applicable Colorado State Implementation Plans (SIPs). The DGCD contains this assessment.

**DATES:** Submit comments on or before August 20, 2007.

**ADDRESSES:** Interested parties may view hard copies of the document in Denver, Monday through Friday, from 8 a.m. to 4 p.m. Mountain Daylight Time at Environmental Services Section, Department of Aviation, City and County of Denver, Elrey B. Jeppesen Terminal Building, Level 6, Room 6619–20, 8400 Peña Boulevard, Denver, CO 80249. Please contact Ms. Aimee Fenlon at 303–342–2636 for appointments.

To request mailed hard copies of the Draft GCD, contact Mr. Dennis Harn, Operations Specialist, Safety Evaluation and Analysis Branch, ANM–240, FAA Northwest Mountain Region Headquarters, 1601 Lind Ave., SW., Suite 560, Renton, WA 98057; telephone: 425–227–2560; e-mail: *Dennis.Harn@faa.gov.*

The DGCD is also available for review electronically on the Department of Transportation's Docket Management System (DMS) at *http://dms.dot.gov/.* Do a simple search for docket number 28041.

You may submit comments, identified by docket number FAA–2007–28041, by any of the following methods:

1. By mail to: Docket Management Facility, U.S. Department of Transportation, 1200 New Jersey Avenue, SE., Washington, DC 20590–0001.
2. By hand delivery to Docket Management Facility, 1200 New Jersey Avenue, SE., Washington, DC, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays;
3. By fax to the Docket Management Facility at 202–493–2251; or
4. By electronic submission through the DMS Web site at *http://dms.dot.gov/submit/.* See **SUPPLEMENTARY INFORMATION** for additional information about electronic filing.

**FOR FURTHER INFORMATION CONTACT:** Mr. Dennis Harn, telephone: 425–277–2560; e-mail; *Dennis.Harn@faa.gov.*

**SUPPLEMENTARY INFORMATION:** The Denver Metropolitan Area is an EPA-designated attainment/maintenance area for the criteria pollutants carbon monoxide, particulate matter with aerodynamic diameter of 10 micrometers or less ($PM_{10}$), and ozone (1-hour standard). In addition, DEN is located in an Early Action Compact area for the 8-hour ozone standard.

The FAA demonstrates in the DGCD that the sum of the existing aircraft operations at DEN plus the proposed aircraft operations by Lynx Aviation is below the forecast values incorporated into the State Implementation Plan (SIP), and therefore aircraft emissions attributed to flights by Lynx Aviation are already accounted for in the SIP emissions inventories. As a result, the FAA can demonstrate that the proposed action conforms to the SIP.

#### Comment Filing Instructions

All submissions received must include the agency name and docket number or Regulatory Information Number (RIN).

You may submit comments electronically through the DMS Web site at *http://dms.dot.gov/submit/.* You have the option of submitting comments either by typing your comment into the DMS or by uploading a previously completed comment document as a file. If you upload a file it must be in one of the following file format types: MS Word (Versions 95–97); MS Word for Mac (Versions 6–8); Rich Text File (RTF); American Standard Code Information Interchange (ASCII) (TXT); Portable Document Format (PDF); or Word Perfect (WPD) (Versions 7–8). See the Electronic Submission Help and Guidelines screen at *http://dms.dot.gov/help/es_help.cfm* for additional guidance.

The FAA will accept comments on the DCGD until August 20, 2007. Written comments must be postmarked and electronic submissions received by not later than midnight, August 20, 2007. After FAA reviews and addresses all comments, FAA will publish a notice of availability of the Final General Conformity Determination.

Issued in Washington, DC on July 16, 2007.

**John M. Allen,**

*Acting Director, Flight Standards Service.*

[FR Doc. 07–3540 Filed 07–19–07; 8:45 am]

**BILLING CODE 4910–13–M**

## DEPARTMENT OF TRANSPORTATION

### Federal Motor Carrier Safety Administration

**[Docket No. FMCSA–2007–28534]**

### Notice of Request for Information (RFI): Commercial Motor Vehicle Driver Risk Factor Study

**AGENCY:** Federal Motor Carrier Safety Administration (FMCSA), DOT.

**ACTION:** Notice; request for information.

**SUMMARY:** In accordance with the Paperwork Reduction Act of 1995, FMCSA announces its plan to submit the Information Collection Request (ICR) described below to the Office of Management and Budget (OMB) for review and approval. This information collection is associated with the agency's study by a research contractor which will investigate commercial motor vehicle driver risk factors. This information collection will aid FMCSA in developing future safety initiatives by examining a wide array of driver and situational factors to determine if they are associated with increased or decreased crash and incident

involvement. On March 23, 2007 FMCSA published a **Federal Register** notice allowing for a 60-day comment period on the ICR. Two comments were received regarding the utility of the survey. These comments will be considered during the information collection activities for the study.

**DATES:** Please send your comments by August 20, 2007. OMB must receive your comments by this date in order to act quickly on the ICR.

**ADDRESSES:** You may submit comments to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 Seventeenth Street, NW., Washington, DC 20503, Attention: DOT/FMCSA Desk Officer.

**FOR FURTHER INFORMATION CONTACT:** Mr. Albert Alvarez, Federal Motor Carrier Safety Administration, Office of Research and Analysis (MC–RRR), Federal Motor Carrier Safety Administration, West Building 6th Floor, 1200 New Jersey Avenue, SE., Washington, DC 20590. Telephone: (202) 385–2387; e-mail: *albert.alvarez@dot.gov.* Office hours are from 8 a.m. to 4 p.m., ET, Monday through Friday, except Federal holidays.

**SUPPLEMENTARY INFORMATION:**

*Title:* Commercial Motor Vehicle Driver Risk Factor Study.

*OMB Control Number:* 2126–XXXX.

*Type of Request:* New information collection.

*Respondents:* Commercial motor vehicle (CMV) drivers and motor carriers.

*Estimated Number of Respondents:* 700 [(600 CMV drivers completing telephone interviews and paper/online questionnaires + 72 of the 600 CMV drivers completing in-person interviews, psychological and perceptual testing, and medical examinations) + 100 motor carriers providing driver records = 700].

*Estimated Time per Response:* The estimated average burden per response is 20 minutes for telephone interviews; 30 minutes for paper/online questionnaires; 4 hours for in-person interviews, including psychological and perceptual testing, and medical examinations; and 30 minutes for motor carriers to locate and deliver respondents' driving records to researchers.

*Expiration Date:* N/A. This is a new information collection.

*Frequency of Response:* This information collection will be a single, nonrecurring event.

*Estimated Total Annual Burden:* 1,124 hours [100 participating carriers × 2 hours to provide information to researchers + 100 non-response carriers × 30 minutes/60 minutes + 600 non-response CMV drivers × 5 minutes/60 minutes + 600 CMV driver telephone interviews × 20 minutes/60 minutes + 600 CMV driver paper/online questionnaires × 30 minutes/60 minutes + 72 in-person interviews, psychological and perceptual testing, and medical examinations × 4 hours + 20 carriers locating and delivering 72 drivers' driving records × 30 minutes per driver/60 minutes = 1,124 hours].

*Background:* The purpose of this study is to identify, verify, quantify, and prioritize commercial motor vehicle (CMV) driver risk factors. Primarily, these factors are personal, such as demographic characteristics, medical conditions, personality traits, and performance capabilities. Risk factors may also include work environmental conditions, such as carrier operations type, and compensation methods. The study will identify risk factors by linking the characteristics of individual drivers with their driving histories, especially the presence or absence of crashes or inspection violations.

*Definitions: Driver risk factors* are personal factors such as demographic characteristics, medical conditions, personality traits, and performance capabilities. Risk factors may also include work environmental conditions, such as carrier operations type, and compensation method.

*Public Comments Invited:* You are asked to comment on any aspect of this information collection, including: (1) Whether the proposed collection is necessary for the FMCSA's performance; (2) the accuracy of the estimated burden; (3) ways for the FMCSA to enhance the quality, usefulness, and clarity of the collected information; and (4) ways that the burden could be minimized without reducing the quality of the collected information.

Issued on: July 11, 2007.

**D. Marlene Thomas,**

*Associate Administrator for Administration.*

[FR Doc. E7–14029 Filed 7–19–07; 8:45 am]

BILLING CODE 4910–EX–P

## DEPARTMENT OF TRANSPORTATION

### Federal Motor Carrier Safety Administration

**[Docket No. FMCSA–2007–27500]**

### Notice of Request for Information (RFI): Revision of an Information Collection: Hazardous Materials Safety Permits (Formerly Hazardous Materials Permit)

**AGENCY:** Federal Motor Carrier Safety Administration (FMCSA), DOT.

**ACTION:** Notice; request for comments.

**SUMMARY:** In accordance with the Paperwork Reduction Act of 1995, FMCSA announces its plan to submit the Information Collection Request (ICR) described below to the Office of Management and Budget (OMB) for review and approval and invites public comment. The FMCSA invites comments on its plan to request OMB approval to revise an existing information collection entitled ''Hazardous Materials (HM) Safety Permits'', OMB Control Number 2126–0030. FMCSA requires companies holding permits to develop a communications plan that allows for the periodic tracking of the shipment. A record of the communications may be kept by either the driver (e.g., recorded in the log book) or the company that contains the time of the call and location of the shipment. These records must be kept, either physically or electronically, for at least six months at the company's principal place of business or readily available to employees at the company's principal place of business.

**DATES:** We must receive your comments on or before September 18, 2007.

**ADDRESSES:** You may submit comments identified by any of the following methods. Please identify your comments by the FMCSA Docket Number FMCSA–2007–27500.

- *Web site: http://dms.dot.gov.* Follow instructions for submitting comments to the Docket.
- *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., e.t., Monday through Friday, except Federal holidays.

*Docket:* For access to the Docket Management System (DMS) to read background documents or comments received, go to *http://dms.dot.gov* at any time or to the 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., e.t., Monday through Friday, except Federal holidays. The DMS is available electronically 24 hours each day, 365 days each year. If you want notification of receipt of your comments, please include a self-addressed, stamped envelope, or postcard or print the acknowledgement page that appears after submitting comments on-line.

*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** on April 11, 2000 (65 FR 19477), or you may visit *http://dms.dot.gov.*

**FOR FURTHER INFORMATION CONTACT:** Mr. James O. Simmons, Hazardous Materials Division, phone (202) 366–6121; FAX (202) 366–3921; or e-mail *james.simmons@dot.gov;* Federal Motor Carrier Safety Administration, DOT, 1200 New Jersey Avenue, SE., Washington, DC 20590. Office hours are from 8 a.m. to 4:30 p.m. EST, Monday through Friday, except Federal Holidays.

**SUPPLEMENTARY INFORMATION:**

**Background**

The Secretary of Transportation (Secretary) is responsible for implementing regulations to issue safety permits for transporting certain hazardous materials in accordance with 49 U.S.C. Section 5101 *et seq.* The HM Safety Permit regulations (49 CFR Part 385) require carriers to complete a ''Combined Motor Carrier Identification Report and HM Safety Permit Application''—form number MCS–150B (See Attachment D). The HM Safety Permit regulations also require carriers to have a security program. As part of the HM Safety Permit regulations, carriers are required to develop and maintain route plans so that law enforcement officials can verify the correct location of the HM shipment. FMCSA requires companies holding permits to develop a communications plan that allows for the periodic tracking of the shipment. This information collection covers the records of the communications that contains the time of the call and location of the shipment. The records may be kept by either the driver (e.g., recorded in the log book) or the company. These records must be kept, either physically or electronically, for at least six months at the company's principal place of business or readily available to employees at the company's principal place of business.

*Title:* Hazardous Materials Safety Permits (formerly Hazardous Materials Permit).

*OMB Control Number:* 2126–0030.

*Type of Request:* Revision of a currently approved collection.

*Respondents:* 2,515 motor carriers of property (Forms MCS–150B) .

*Frequency:* On occasion. The changes will occur at the time of renewal, update or change of information.

*Estimated Average Burden per Response:* 5 minutes. The communication between motor carriers and their drivers must take place at least two times per day and it is estimated that it will take 5 minutes to maintain a daily communication record for each driver.

*Estimated Total Annual Burden Hours:* 130,780 hours. 52 annual hours per carrier [5 minutes/60 minutes per trip × 1,570,391 estimated annual trips for carriers/2,515 carriers = 52 hours]. 130,780 total annual burden hours [52 annual hours per carrier × 2,515 carriers = 130,780 hours].

*Public Comments Invited:* You are asked to comment on any aspect of this information collection, including: (1) Whether the proposed collection is necessary for the FMCSA's performance; (2) the accuracy of the estimated burden; (3) ways for the FMCSA to enhance the quality, usefulness, and clarity of the collected information; and (4) ways that the burden could be minimized without reducing the quality of the collected information. The agency will summarize and/or include your comments in the request for OMB's clearance of this information collection.

Issued On: July 11, 2007.

**D. Marlene Thomas,**

*Associate Administrator for Administration.*

[FR Doc. E7–14032 Filed 7–19–07; 8:45 am]

**BILLING CODE 4910–EX–P**

## DEPARTMENT OF TRANSPORTATION

### Federal Motor Carrier Safety Administration

**[Docket No. FMCSA–2007–27897]**

### Qualification of Drivers; Exemption Applications; Vision

**AGENCY:** Federal Motor Carrier Safety Administration (FMCSA), DOT.

**ACTION:** Notice of applications for exemptions; request for comments.

**SUMMARY:** FMCSA announces receipt of applications from 64 individuals for exemptions from the vision requirement in the Federal Motor Carrier Safety Regulations. If granted, the exemptions would enable these individuals to qualify as drivers of commercial motor vehicles (CMVs) in interstate commerce without meeting the Federal vision standard.

**DATES:** Comments must be received on or before August 20, 2007.

**ADDRESSES:** You may submit comments identified by Department of Transportation (DOT) Docket Management System (DMS) Docket Number FMCSA–2007–27897 using any of the following methods:

- *Web Site: http://dmses.dot.gov/submit.* Follow the instructions for submitting comments on the DOT electronic docket site.
- *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 20590–0001.
- *Hand Delivery:* Room W12–140 on the ground level of the West Building, 1200 New Jersey Avenue, SE., Washington, DC, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.
- *Federal eRulemaking Portal:* Go to *http://www.regulations.gov.* Follow the online instructions for submitting comments.

*Instructions:* All submissions must include the Agency name and docket number for this notice. Note that all comments received will be posted without change to *http://dms.dot.gov* including any personal information provided. Please see the Privacy Act heading for further information.

*Docket:* For access to the docket to read background documents or comments received, go to *http://dms.dot.gov* at any time or Room W12–140 on the ground level of the West Building, 1200 New Jersey Avenue, SE., Washington, DC, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The DMS is available 24 hours each day, 365 days each year. If you want acknowledgment that we received your comments, please include a self-addressed, stamped envelope or postcard or print the acknowledgement page that appears after submitting comments on-line.

*Privacy Act:* Anyone may search the electronic form of all comments received into any of our dockets by the name of the individual submitting the comment (or of the person signing the comment, if submitted 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; Apr. 11, 2000). This information is also available at *http://dms.dot.gov.*

**FOR FURTHER INFORMATION CONTACT:** Dr. Mary D. Gunnels, Chief, Physical Qualifications Division, 202–366–4001, FMCSA, Room W64–224, U.S. Department of Transportation, 1200 New Jersey Avenue, SE., Washington, DC 20590–0001. Office hours are from 8:30 a.m. to 5 p.m. Monday through Friday, except Federal holidays.

**SUPPLEMENTARY INFORMATION:**

## Background

Under 49 U.S.C. 31136(e) and 31315, FMCSA may grant an exemption for a 2-year period if it finds ''such exemption would likely achieve a level of safety that is equivalent to, or greater than, the level that would be achieved absent such exemption.'' FMCSA can renew exemptions at the end of each 2-year period. The 64 individuals listed in this notice each have requested an exemption from the vision requirement in 49 CFR 391.41(b)(10), which applies to drivers of CMVs in interstate commerce. Accordingly, the Agency will evaluate the qualifications of each applicant to determine whether granting the exemption will achieve the required level of safety mandated by statute.

## Qualifications of Applicants

*John W. Black*

Mr. Black, age 43, has loss of vision in his right eye due to a traumatic injury sustained as a child. The visual acuity in his right eye is light perception vision and in the left, 20/20. Following an examination in 2006, his ophthalmologist noted, ''In my medical opinion John has sufficient vision to perform the driving task required to operate a commercial vehicle.'' Mr. Black reported that he has driven straight trucks for 5 years, accumulating 120,000 miles, and tractor-trailer combinations for 11 years, accumulating 550,000 miles. He holds a Class A Commercial Driver's License (CDL) from Arizona. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Ronald D. Boeve*

Mr. Boeve, 54, has had amblyopia in his left eye since childhood. The best corrected visual acuity in his right eye is 20/20 and in the left, 20/200. Following an examination in 2006, his optometrist noted, ''In my professional opinion, Ron Boeve has ample vision to perform the driving tasks required to operate a commercial vehicle as he has done for 30 years with no change in his visual condition.'' Mr. Boeve reported that he has driven tractor-trailer combinations for 33 years, accumulating 3.3 million miles. He holds a Class A CDL from Michigan. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Paul T. Breitigan*

Mr. Breitigan, 55, has loss of vision in his right eye due to histoplasmosis with choroidal neovascularization since 2003. The best corrected visual acuity in his right eye is 20/200 and in the left, 20/20. Following an examination in 2006, his ophthalmologist noted, ''Your visual acuity qualifies for legal driving vision. This vision is sufficient to perform the driving tasks required to operate a commercial vehicle.'' Mr. Breitigan reported that he has driven tractor-trailer combinations for 31 years, accumulating 3.7 million miles. He holds a Class A CDL from Ohio. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*John A. Bridges*

Mr. Bridges, 44, has had ambylopia in his right eye since childhood. The best corrected visual acuity in his right eye is 20/80 and in the left, 20/20. Following an examination in 2006, his ophthalmologist noted, ''Mr. Bridges meets all CDL requirements and I can easily certify that he has sufficient vision to perform driving tasks required to operate a commercial vehicle.'' Mr. Bridges reported that he has driven straight trucks for 20 years, accumulating 400,000 miles. He holds a Class A CDL from Georgia. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Edward G. Brown*

Mr. Brown, 79, has loss of vision in his right eye due to age-related macular degeneration since 2001. The best corrected visual acuity in his right eye is 20/60 and in the left, 20/30. Following an examination in 2007, his optometrist noted, ''In my medical opinion, Mr. Brown has sufficient vision to perform the driving tasks required to operate a commercial vehicle.'' Mr. Brown reported that he has driven tractor-trailer combinations for 19 years, accumulating 760,000 miles. He holds a Class A CDL from Ohio. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Edwin L. Bupp*

Mr. Bupp, 36, has had amblyopia in his left eye since childhood. The best corrected visual acuity in his right eye is 20/20 and in the left, 20/200. Following an examination in 2007, his optometrist noted, ''When considering Mr. Bupp's examination results and comparing the criteria set up by your department, I believe he has sufficient vision to perform the driving tasks required to operate a commercial vehicle.'' Mr. Bupp reported that he has driven tractor-trailer combinations for 13 years, accumulating 2 million miles. He holds a Class A CDL from Pennsylvania. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Charles E. Castle*

Mr. Castle, 65, has complete loss of vision in his right eye due to a traumatic injury sustained as a child. The best corrected visual acuity in his left eye is 20/25. Following an examination in 2007, his optometrist noted, ''I certify that this patient's visual status is sufficient to perform driving tasks required to operate a commercial vehicle.'' Mr. Castle reported that he has driven straight trucks for 9 years, accumulating 900,000 miles, and tractor-trailer combinations for 13 years, accumulating 910,000 miles. He holds a Class A CDL from Ohio. His driving record for the last 3 years shows one crash, which he was cited for, and no convictions for moving violations in a CMV.

*Joel C. Conrad*

Mr. Conrad, 47, has had amblyopia in his left eye since birth. The best corrected visual acuity in his right eye is 20/20 and in the left, 20/60. Following an examination in 2007, his ophthalmologist noted, ''In my medical opinion, Joel Conrad has sufficient vision to perform the driving tasks to operate a commercial vehicle.'' Mr. Conrad reported that he has driven buses for 10 years, accumulating 120,000 miles. He holds a Class B CDL from New York. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Duane C. Conway*

Mr. Conway, 57, has complete loss of vision in his right eye due to a retinal detachment sustained approximately 30 years ago. The visual acuity in his right eye is 20/20. Following an examination in 2006, his ophthalmologist noted, ''Mr. Conway's vision has been sufficient for him to obtain and operate commercial vehicles for decades. His vision is unchanged. Therefore, in my opinion, he still has sufficient vision to perform the driving tasks required to operate a commercial vehicle.'' Mr. Conway reported that he has driven straight trucks for 6 years, accumulating 288,000 miles, and tractor-trailer combinations for 8 years, accumulating 800,000 miles. He holds a Class A CDL from Nevada. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*David L. Cummings*

Mr. Cummings, 54, has complete loss of vision in his left eye due to a traumatic injury sustained as a child. The visual acuity in his right eye is 20/20. Following an examination in 2006, his optometrist noted, ''I believe he has sufficient vision to operate a commercial vehicle.'' Mr. Cummings reported that he has driven straight trucks for 24 years, accumulating 600,000 miles, and tractor-trailer combinations for 9 years, accumulating 45,000 miles. He holds a Class A CDL from Illinois. His driving record for the last 3 years shows no crashes and one conviction for a moving violation, speeding in a CMV. He exceeded the speed limit by 12 mph.

*Brian W. Curtis*

Mr. Curtis, 52, has had amblyopia in his right eye since birth. The best corrected visual acuity in his right eye is 20/60 and in the left, 20/20. Following an examination in 2007, his optometrist noted, ''Brian should not have any visual difficulties performing the driving tasks required for a commercial vehicle.'' Mr. Curtis reported that he has driven straight trucks for 34 years, accumulating 884,000 miles. He holds a Class B CDL from Illinois. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Roger D. Davidson, Sr.*

Mr. Davidson, 50, has had amblyopia in his right eye since childhood. The best corrected visual acuity in his right eye is 20/200 and in the left, 20/15. Following an examination in 2007, his optometrist noted, ''In my opinion, Mr. Davidson is ok to drive a commercial vehicle.'' Mr. Davidson reported that he has driven tractor-trailer combinations for 10 years, accumulating 1 million miles, and buses for 3 years, accumulating 120,000 miles. He holds a Class A CDL from Illinois. His driving record for the last 3 years shows no crashes and one conviction for a moving violation in a CMV, failure to obey a traffic signal.

*Richard A. Davis, Sr.*

Mr. Davis, 57, has complete loss of vision in his left eye due to a traumatic injury sustained as a child. The visual acuity in his right eye is 20/20. Following an examination in 2006, his optometrist noted, ''I feel Mr. Davis has sufficient vision to perform the driving task of a commercial vehicle with the restriction of passenger and driver side mirrors.'' Mr. Davis reported that he has driven straight trucks for 19 years, accumulating 760,000 miles. He holds a Class B CDL from Illinois. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Thomas E. Dixon*

Mr. Dixon, 43, has a prosthetic left eye due to a traumatic injury sustained as a child. The best corrected visual acuity in his right eye is 20/20. Following an examination in 2006, his ophthalmologist noted, ''In my medical opinion, he has sufficient vision to perform the driving tasks required to operate a commercial vehicle.'' Mr. Dixon reported that he has driven straight trucks for 15 years, accumulating 622,500 miles. He holds a Class B CDL from Michigan. His driving record for the last 3 years shows no crashes and one conviction for a moving violation, speeding in a CMV. He exceeded the speed limit by 15 mph.

*Robin C. Duckett*

Mr. Duckett, 51, has complete loss of vision in his left eye due to phthisis bulbi, secondary to probable congenital inflammation. The visual acuity in his right eye is 20/20. Following an examination in 2007, his ophthalmologist noted, ''Because the poor vision in his left eye was present at birth, Mr. Duckett has adjusted and developed monocular cues allowing him to function similarly to individuals with regular binocular vision. He does not have difficulty judging distance. He has apparently been a very safe driver. I think he should be considered for a waiver concerning truck driving certification limited by poor vision in one eye.'' Mr. Duckett reported that he has driven tractor-trailer combinations for 31 years, accumulating 1.4 million miles. He holds a Class A CDL from South Carolina. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Steven C. Durst*

Mr. Durst, 56, has complete loss of vision in his left eye due to a corneal scar resulting from a traumatic injury sustained as a child. The visual acuity in his right eye is 20/20. Following an examination in 2007, his optometrist noted, ''Mr. Durst has had poor visual acuity in his left eye since the age of thirteen and has performed the tasks of driving a commercial vehicle for some time without change in his visual status. I believe, based on the results of this examination, that he has sufficient visual capabilities to continue to do so.'' Mr. Durst reported that he has driven straight trucks for 2 years, accumulating 2,000 miles, and tractor-trailer combinations for 30 years, accumulating 2 million miles. He holds a Class A CDL from Ohio. His driving record for the last 3 years shows no crashes and two convictions for moving violations, one for an improper turn in a CMV and one for speeding in a CMV. He exceeded the speed limit by 11 mph.

*Marco A. Esquivel*

Mr. Esquivel, 46, has loss of vision in his left eye due to a traumatic injury sustained as a child. The visual acuity in his right eye is 20/20 and in the left, 20/150. Following an examination in 2006, his optometrist noted, ''I certify that Mr. Esquivel has sufficient vision to perform driving tasks required to operate a commercial vehicle.'' Mr. Esquivel reported that he has driven straight trucks for 9 years, accumulating 198,000 miles, and tractor-trailer combinations for 7 years, accumulating 210,000 miles. He holds a Class C operator's license from California. His driving record for the last 3 years shows one crash and no convictions for moving violations in a CMV.

*Charles D. Grady*

Mr. Grady, 45, has a retinal scar on his left eye due to a traumatic injury sustained as a child. The best corrected visual acuity in his right eye is 20/15 and in the left, 20/400. Following an examination in 2006, his optometrist noted, ''I certify that Mr. Grady's visual deficiency is stable and that he has adequate vision and visual fields to drive tractor-trailers.'' Mr. Grady reported that he has driven straight trucks for 5 years, accumulating 25,000 miles, and tractor-trailer combinations for 20 years, accumulating 2 million miles. He holds a Class C operator's license from Georgia. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Paul L. Graunstadt*

Mr. Graunstadt, 62, has had amblyopia in his left eye since birth. The best corrected visual acuity in his right eye is 20/20 and in the left, 20/400. Following an examination in 2007, his optometrist noted, ''In summary, my professional opinion is Mr. Graunstadt has sufficient vision to perform driving tasks as required to operate a commercial vehicle.'' Mr. Graunstadt reported that he has driven straight trucks for 38 years, accumulating 1.3 million miles. He holds a Class C chauffeur's license from Michigan. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Danny R. Gray*

Mr. Gray, 41, has loss of vision in his right eye due to a spontaneous retinal detachment in 1996. The best corrected visual acuity in his right eye is count-finger vision and in the left, 20/15. Following an examination in 2007, his optometrist noted, ''In my professional opinion, Mr. Gray does have sufficient vision to perform the driving tasks required to operate a commercial vehicle as his left eye has vision correctable to 20/15.'' Mr. Gray reported that he has driven straight trucks for 11 years, accumulating 165,000 miles, and tractor-trailer combinations for 8 years, accumulating 136,000 miles. He holds a Class D operator's license from Oklahoma. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Louis E. Henry, Jr.*

Mr. Henry, 52, has had amblyopia in his left eye since childhood. The best corrected visual acuity in his right eye is 20/20 and in the left, 20/200. Following an examination in 2007, his optometrist noted, ''Visually able to operate commercial vehicle.'' Mr. Henry reported that he has driven straight trucks for 7 years, accumulating 350,000 miles, and tractor trailer combinations for 3 months, accumulating 5,000 miles. He holds a Class A CDL from Kentucky. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Raymond L. Herman*

Mr. Herman, 23, has had amblyopia in his right eye since birth. The visual acuity in his right eye is 20/400 and in the left, 20/20. Following an examination in 2007, his optometrist noted, ''I certify, in my medical opinion, that Mr. Herman has sufficient vision to perform the driving tasks required to operate a commercial vehicle.'' Mr. Herman reported that he has driven straight trucks for 4 years, accumulating 140,000 miles. He holds a Class B CDL from New York. His driving record for the last 3 years shows one crash and one conviction for a moving violation in a CMV, failure to obey a traffic device.

*Jesse R. Hillhouse, Jr.*

Mr. Hillhouse, 40, has had amblyopia in his left eye since birth. The best corrected visual acuity in his right eye is 20/25 and in the left, 20/70. Following an examination in 2007, his optometrist noted, ''It is my opinion that with corrective lenses, Mr. Hillhouse does have sufficient vision to perform the driving tasks required to operate a commercial vehicle.'' Mr. Hillhouse reported that he has driven straight trucks for 31/2 years, accumulating 136,500 miles. He holds a Class B CDL from Oklahoma. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Billy R. Holdman*

Mr. Holdman, 49, has loss of vision in his left eye due to a central retinal vein occlusion since 2000. The visual acuity in his right eye is 20/20 and in the left, 20/80. Following an examination in 2007, his ophthalmologist noted, ''In my opinion, he has sufficient vision to perform the driving tasks required to operate a commercial vehicle.'' Mr. Holdman reported that he has driven straight trucks for 19 years, accumulating 570,000 miles, and tractor-trailer combinations for 10 years, accumulating 52,000 miles. He holds a Class A CDL from Illinois. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Marshall L. Jackson*

Mr. Jackson, 49, has had constant alternating exotropia since birth. The best corrected visual acuity in his right eye is 20/25 and in the left, 20/20. Due to his condition, Mr. Jackson lacks binocular vision. Following an examination in 2007, his optometrist noted, ''It is my opinion that this patient's safe operation of a commercial vehicle would not be hindered by his visual status.'' Mr. Jackson reported that he has driven straight trucks for 23 years, accumulating 1.5 million miles, and tractor-trailer combinations for 1 year, accumulating 15,000 miles. He holds a Class A CDL from Texas. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Ray C. Johnson*

Mr. Johnson, 47, has a prosthetic right eye due to a traumatic injury sustained in 1999. The visual acuity in his left eye is 20/20. Following an examination in 2006, his ophthalmologist noted, ''In my opinion, even though the patient only has one eye, he has sufficient vision to perform the driving tests required to operate a commercial vehicle.'' Mr. Johnson reported that he has driven straight trucks for 6 years, accumulating 420,000 miles, and tractor-trailer combinations for 15 years, accumulating 1.2 million miles. He holds a Class A CDL from Arkansas. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Terry R. Jones*

Mr. Jones, 33, has had amblyopia in his left eye since birth. The best corrected visual acuity in his right eye is 20/20 and in the left, 20/60. Following an examination in 2007, his optometrist noted, ''I certainly believe that Mr. Jones has sufficient vision to operate a commercial vehicle.'' Mr. Jones reported that he has driven straight trucks for 10 years, accumulating 343,000 miles. He holds a Class A CDL from Missouri. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Randall H. Keil*

Mr. Keil, 54, has loss of vision in his left eye due to an episode of papillitis that occurred in 1999. The best corrected visual acuity in his right eye is 20/20 and in the left, 20/30. The horizontal field of vision in his right eye is 110 degrees and in the left, 35 degrees. Following an examination in 2006, his optometrist noted, ''Based on my findings, I feel that his patient has sufficient vision to perform the driving tests required to operate a commercial vehicle.'' Mr. Keil reported that he has driven straight trucks for 29 years, accumulating 100,050 miles. He holds a Class C operator's license from California. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Gregory K. Lilly*

Mr. Lilly, 46, has loss of vision in his left eye due to a traumatic injury sustained in 2002. The visual acuity in his right eye is 20/20 and in the left, 20/200. Following an examination in 2007, his ophthalmologist noted, ''He has been working as a commercial driver since his injury. I am confident he has sufficient vision to perform his driving tasks.'' Mr. Lilly reported that he has driven straight trucks for 5 years, accumulating 125,000 miles, and tractor-trailer combinations for 24 years, accumulating 1.8 million miles. He holds a Class A CDL from West Virginia. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Paul G. Mathes*

Mr. Mathes, 59, has loss of vision in his left eye due to a focal thermal injury sustained in 1991. The best corrected visual acuity in his right eye is 20/20 and in the left, 20/50. Following an examination in 2007, his optometrist noted, ''It is my judgment that Mr. Paul Graham Mathes has sufficient vision to perform the driving tasks required to operate a commercial vehicle.'' Mr. Mathes reported that he has driven straight trucks for 10 years, accumulating 45,000 miles, and tractor trailer combinations for 10 years, accumulating 500,000 miles. He holds a Class A CDL from Washington. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*John T. McWilliams*

Mr. McWilliams, 49, has had amblyopia in his left eye since birth. The best corrected visual acuity in his right eye is 20/20 and in the left, 20/60. Following an examination in 2007, his optometrist noted, ''In my opinion, John has sufficient vision to operate a commercial vehicle as he has for many years.'' Mr. McWilliams reported that he has driven straight trucks for 32 years, accumulating 640,000 miles. He holds a Class C operator's license from Iowa. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Robert A. Miller*

Mr. Miller, 60, has had amblyopia in his left eye since childhood. The best corrected visual acuity in his right eye is 20/20 and in the left, 20/60. Following an examination in 2006, his optometrist noted, ''Mr. Miller does have sufficient vision to safely operate a commercial vehicle, subject, of course, to Kentucky driver qualification requirements.'' Mr. Miller reported that he has driven tractor-trailer combinations for 34 years, accumulating 5 million miles. He holds a Class A CDL from Kentucky. His driving record for the last 3 years shows one crash and one conviction for a moving violation, speeding in a CMV. He exceeded the speed limit by 11 mph.

*Rodney R. Miller*

Mr. Miller, 49, has had amblyopia in his left eye since childhood. The visual acuity in his right eye is 20/20 and in the left, 20/200. Following an examination in 2007, his optometrist noted, ''In my opinion, Mr. Miller has sufficient vision to operate a commercial vehicle.'' Mr. Miller reported that he has driven straight trucks for 33 years, accumulating 3 million miles, and tractor-trailer combinations for 33 years, accumulating 3 million miles. He holds a Class A CDL from Pennsylvania. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Stuart T. Miller*

Mr. Miller, 46, has a prosthetic left eye due to a traumatic injury sustained as a child. The best corrected visual acuity in his right eye is 20/20. Following an examination in 2007, his ophthalmologist noted, ''Mr. Miller's vision is stable and in my opinion his vision is sufficient to perform the driving tests required to operate a commercial vehicle.'' Mr. Miller reported that he has driven straight trucks for 25 years, accumulating 500,000 miles, and tractor-trailer combinations for 25 years, accumulating 2.5 million miles. He holds a Class A CDL from Florida. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*James J. Mitchell*

Mr. Mitchell, 45, has complete loss of vision in his right eye due to optic atrophy from a traumatic cataract sustained in 2003. The visual acuity in his left eye is 20/20. Following an examination in 2007, his optometrist noted, ''In my opinion, Mr. Mitchell has sufficient vision to operate a commercial vehicle.'' Mr. Mitchell reported that he has driven tractor-trailer combinations for 20 years, accumulating 2.5 million miles. He holds a Class A CDL from North Carolina. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Terry W. Moore*

Mr. Moore, 46, has complete loss of vision in his right eye due to amblyopia since birth. The visual acuity in his left eye is 20/20. Following an examination in 2006, his optometrist noted, ''In my opinion, Mr. Moore has sufficient vision to operate a commercial vehicle.'' Mr. Moore reported that he has driven straight trucks for 3 years, accumulating 45,000 miles. He holds a Class D chaffeur's license from Louisiana. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Arnold R. Moreland*

Mr. Moreland, 44, has had amblyopia in his left eye since birth. The best corrected visual acuity in his right eye is 20/20 and in the left, 20/400. Following an examination in 2006, his optometrist noted, ''I certify in my medical opinion that Mr. Moreland has sufficient vision to perform driving tasks required to operate a commercial vehicle.'' Mr. Moreland reported that he has driven straight trucks for 7 years, accumulating 504,000 miles, and tractor-trailer combinations for 5 years, accumulating 150,000 miles. He holds a Class A CDL from Virginia. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Andrew M. Nurnberg*

Mr. Nurnberg, 35, has complete loss of vision in his right eye due to optic nerve atrophy resulting from a traumatic injury sustained as a child. The visual acuity in his left eye is 20/20. Following an examination in 2007, his optometrist noted, ''I, Dr. Scott A Baylard, feel in my medical opinion that he has sufficient vision to perform the driving tasks required to operate a commercial vehicle.'' Mr. Miller reported that he has driven straight trucks for 7½ years, accumulating 450,000 miles. He holds a Class C operator's license from Georgia. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Raymond K. Ochse*

Mr. Ochse, 53, has loss of vision in his left eye due to strabismus since childhood. The visual acuity in his right eye is 20/20 and in the left, 20/60. Following an examination in 2007, his ophthalmologist noted, ''In my opinion, I do not feel that there is any ocular reason for the patient not to be able to drive any vehicle, commercial or otherwise.'' Mr. Ochse reported that he has driven straight trucks for 2 years, accumulating 60,000 miles, and tractor-trailer combinations for 32 years, accumulating 1.9 million miles. He holds a Class A CDL from New Jersey. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Charles D. Oestreich*

Mr. Oestreich, 44, had enucleation of his right eye due to cancer in 2003. The best corrected visual acuity in his left eye is 20/20. Following an examination in 2007, his ophthalmologist noted, ''In my medical opinion, Mr. Oestrich has sufficient vision to perform the driving tests required to operate a commercial vehicle.'' Mr. Oestreich reported that he has driven straight trucks for 14 years, accumulating 770,000 miles. He holds a Class A CDL from Minnesota. His driving record for the last 3 years shows no crashes and one conviction for a moving violation, speeding in a CMV. He exceeded the speed limit by 13 mph.

*Robert G. Owens*

Mr. Owens, 60, has had amblyopia in his left eye since childhood. The best corrected visual acuity in his right eye is 20/20 and in the left, 20/100. Following an examination in 2006, his optometrist noted, ''In my opinion, Mr. Owens has sufficient vision, with his glasses on, to operate a commercial vehicle.'' Mr. Owens reported that he has driven straight trucks for 30 years, accumulating 1.5 million miles, tractor-trailer combinations for 30 years, accumulating 2.3 million miles, and buses for 3 years, accumulating 45,000 miles. He holds a Class A CDL from Kentucky. His driving record for the last 3 years shows one crash and no convictions for moving violations in a CMV.

*Kenneth R. Pedersen*

Mr. Pedersen, 69, has loss of vision in his right eye due to a macular hole sustained in 2001. The best corrected visual acuity in his right eye is 20/200 and in the left, 20/20. Following an examination in 2006, his ophthalmologist noted, ''It is my medical opinion that Mr. Pedersen has sufficient vision to perform driving tasks required for a commercial vehicle.'' Mr. Pedersen reported that he has driven straight trucks for 46 years, accumulating 230,000 miles. He holds a Class B CDL from Montana. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Joshua R. Perkins*

Mr. Perkins, 25, has loss of vision in his left eye due to a retinal detachment as a result of a traumatic injury sustained as a child. The visual acuity in his right eye is 20/20 and in the left, 20/400. Following an examination in 2007, his ophthalmologist noted, ''I see no reason why he would not be able to operate a commercial vehicle.'' Mr. Perkins reported that he has driven straight trucks for 10 years, accumulating 150,000 miles, and tractor-trailer combinations for 7 years, accumulating 49,000 miles. He holds a Class D operator's license from Idaho. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Donald F. Plouf*

Mr. Plouf, 60, has loss of vision in his right eye due to a retinal detachment resulting from a traumatic injury sustained over 30 years ago. The best corrected visual acuity in his right eye is 20/400 and in the left, 20/20. Following an examination in 2007, his ophthalmologist noted, ''It is my medical opinion that he has sufficient vision to perform the driving tasks required to operate a commercial vehicle.'' Mr. Plouf reported that he has driven tractor-trailer combinations for 17 years, accumulating 2.3 million miles. He holds a Class A CDL from Florida. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Willie L. Ponders*

Mr. Ponders, 79, has loss of vision in his left eye since a traumatic injury sustained approximately 30 years ago. The best corrected visual acuity in his right eye is 20/20 and in the left, 20/60. Following an examination in 2007, his optometrist noted, ''Mr. Ponders has sufficient vision to perform the driving tasks required to operate a commercial vehicle.'' Mr. Ponders reported that he has driven straight trucks for 50 years, accumulating 1.2 million miles, and tractor-trailer combinations for 10 years, accumulating 1 million miles. He holds a Class C operator's license from Georgia. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Eligio M. Ramirez*

Mr. Ramirez, 41, has loss of vision in his left eye due to neovascular glaucoma since 1994. The best corrected visual acuity in his right eye is 20/20 and in the left, light perception. Following an examination in 2006, his ophthalmologist noted, ''I certify that in my medical opinion he has sufficient vision to perform the driving tasks required to operate a commercial vehicle.'' Mr. Ramirez reported that he has driven tractor-trailer combinations for 13 years, accumulating 1.9 million miles. He holds a Class A CDL from Texas. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Victor C. Richert*

Mr. Richert, 61, has loss of vision in his left eye due to a traumatic injury sustained as a child. The best corrected visual acuity in his right eye is 20/20 and in the left, 20/400. Following an examination in 2007, his optometrist noted, ''There is no limitation on my exam to prevent Mr. Richert from successfully operating a commercial vehicle.'' Mr. Richert reported that he has driven straight trucks for 43 years, accumulating 430,000 miles, and tractor-trailer combinations for 43 years, accumulating 2.6 million miles. He holds a Class A CDL from Oregon. His driving record for the last 3 years shows no crashes and one conviction for a moving violation, following too closely in a CMV.

*Elvis E. Rogers, Jr.*

Mr. Rogers, 34, has had amblyopia in his left eye since childhood. The visual acuity in his right eye is 20/20 and in the left, 20/200. Following an examination in 2007, his optometrist noted, ''I, Guy R. Beavers, O.D., feel that in my medical opinion, Elvis Rogers has sufficient vision to perform the driving tasks required to operate a commercial vehicle.'' Mr. Rogers reported that he has driven straight trucks for 2 years, accumulating 97,800 miles, and tractor-trailer combinations for 7 years, accumulating 944,400 miles. He holds a Class A CDL from Texas. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Garry L. Rogers*

Mr. Rogers, 58, has had amblyopia in his left eye since childhood. The best corrected visual acuity in his right eye is 20/20 and in the left, 20/150. Following an examination in 2006, his optometrist noted, ''In my opinion, Mr. Rogers has sufficient vision to drive a commercial vehicle.'' Mr. Rogers reported that he has driven straight trucks for 2 years, accumulating 23,500 miles, and tractor-trailer combinations for 9 years, accumulating 744,993 miles. He holds a Class A CDL from Colorado. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Craig R. Saari*

Mr. Saari, 45, has had amblyopia in his left eye since childhood. The best corrected visual acuity in his right eye is 20/20 and in the left, 20/60. Following an examination in 2007, his ophthalmologist noted, ''I do not feel that this visual deficiency in his left eye would prevent him from successfully operating a commercial vehicle.'' Mr. Saari reported that he has driven tractor-trailer combinations for 21 years, accumulating 945,000 miles. He holds a Class A CDL from Minnesota. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Jerry L. Schroder*

Mr. Schroder, 65, has a prosthetic left eye due to a traumatic injury sustained as a child. The visual acuity in his right eye is 20/20. Following an examination in 2007, his optometrist noted, ''His visual acuity plus his total degree of remaining visual field for his right eye would indicate to me he has sufficient vision to perform driving tasks that might be required to operate a commercial vehicle.'' Mr. Schroder reported that he has driven straight trucks for 15 years, accumulating 750,000 miles, and tractor-trailer combinations for 40 years, accumulating 3 million miles. He holds a Class A CDL from Illinois. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Gerald J. Shamla*

Mr. Shamla, 66, has had amblyopia in his left eye since childhood. The best corrected visual acuity in his right eye is 20/20 and in the left, count-finger vision. Following an examination in 2007, his ophthalmologist noted, ''In my opinion, the patient's visual functioning is stable and there is no reason to believe that this patient would have any difficulty performing the driving tasks required to operate a commercial motor vehicle in interstate commerce.'' Mr. Shamla reported that he has driven straight trucks for 47 years, accumulating 549,900 miles. He holds a Class A CDL from Minnesota. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Willie C. Smith*

Mr. Smith, 58, has had amblyopia in his left eye since childhood. The best corrected visual acuity in his right eye is 20/20 and in the left, 20/60. Following an examination in 2007, his optometrist noted, ''His vision in the right eye is fully correctable and his peripheral field of vision is within normal limits and should be more than adequate for commercial vehicle driving/operating.'' Mr. Smith reported that he has driven tractor-trailer combinations for 38 years, accumulating 4.6 million miles. He holds a Class A CDL from Florida. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Lanny R. Spears*

Mr. Spears, 59, has a retinal scar in his left eye due to a traumatic injury sustained 34 years ago. The best corrected visual acuity in his right eye is 20/20 and in the left, 20/200. Following an examination in 2006, his optometrist noted, ''In my opinion, Mr. Spears is able to see well enough to operate a commercial vehicle without glasses.'' Mr. Spears reported that he has driven tractor-trailer combinations for 20 years, accumulating 2 million miles. He holds a Class A CDL from Mississippi. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Lawrence E. Stabeno*

Mr. Stabeno, 58, has had amblyopia in his left eye since childhood. The best corrected visual acuity in his right eye is 20/20 and in the left, 20/200. Following an examination in 2007, his optometrist noted, ''I feel that he has sufficient vision to perform the driving tasks required to operate a commercial vehicle.'' Mr. Stabeno reported that he has driven straight trucks for 19 years, accumulating 779,000 miles, and tractor-trailer combinations for 9 years, accumulating 156,600 miles. He holds a Class A CDL from Texas. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Larry D. Steiner*

Mr. Steiner, 49, has loss of vision in his left eye due to a traumatic injury sustained in 2001. The best corrected visual acuity in his right eye is 20/15 and in the left, 20/400. Following an examination in 2007, his optometrist noted, ''I certify, in my opinion, that Mr. Steiner has sufficient vision to perform the driving tasks required to operate a commercial vehicle.'' Mr. Steiner reported that he has driven tractor-trailer combinations for 22 years, accumulating 1.2 million miles. He holds a Class A CDL from Minnesota. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Robert S. Swaen*

Mr. Swaen, 37, has optic nerve damage in his left eye due to a traumatic injury sustained in 1997. The visual acuity in his right eye is 20/20 and in the left, 20/60. Following an examination in 2007, his ophthalmologist noted, ''The patient has normal vision fields and in my opinion Mr. Swaen has sufficient vision to perform the driving tasks required to operate a commercial vehicle.'' Mr. Swaen reported that he has driven straight trucks for 15 years, accumulating 1.2 million miles. He holds a Class B CDL from Wyoming. His driving record for the last 3 years shows no crashes and one conviction for a moving violation, speeding in a CMV. He exceeded the speed limit by 13 mph.

*Robert L. Thies*

Mr. Thies, 48, has loss of vision in his right eye due to myopia since childhood. The best corrected visual acuity in his right eye is 20/200 and in the left, 20/20. Following an examination in 2006, his ophthalmologist noted, ''In my opinion, Mr. Thies does have sufficient vision to operate a commercial vehicle.'' Mr. Thies reported that he has driven straight trucks for 25 years, accumulating 1.3 million miles, and tractor-trailer combinations for 25 years, accumulating 2.5 million miles. He holds a Class A CDL from Indiana. His driving record for the last 3 years shows no crashes and one conviction for a moving violation, speeding in a CMV. He exceeded the speed limit by 12 mph.

*David R. Thomas*

Mr. Thomas, 44, has complete loss of vision in his left eye due to a traumatic injury sustained in 1983. The visual acuity in his right eye is 20/20. Following an examination in 2007, his optometrist noted, ''In my medical opinion, he has sufficient vision to perform the driving task required to operate a commercial vehicle.'' Mr. Thomas reported that he has driven straight trucks for 26 years, accumulating 520,000 miles. He holds a Class B CDL from Alabama. His driving record for the last 3 years shows no crashes and no convictions for moving violation in a CMV.

*Anthony T. Truiolo*

Mr. Truiolo, 38, has complete loss of vision in his left eye due to a traumatic injury sustained as a child. The best corrected visual acuity in his right eye is 20/15. Following an examination in 2007, his ophthalmologist noted, ''In my opinion, Mr. Truiolo has sufficient vision to perform the driving tasks required to operate a commercial vehicle.'' Mr. Truiolo reported that he has driven straight trucks for 4½ years, accumulating 12,600 miles. He holds a Class D operator's license from Connecticut. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Gregory A. VanLue*

Mr. VanLue, 45, has a prosthetic left eye due to a traumatic injury sustained as a child. The best corrected visual acuity in his right eye is 20/15. Following an examination in 2007, his ophthalmologist noted, ''It is my professional opinion that he be considered for a waiver to continue to drive commercially as requested.'' Mr. VanLue reported that he has driven straight trucks for 8 years, accumulating 83,200 miles. He holds a Class D operator's license from Florida. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

*Karl A. Weinert*

Mr. Weinert, 48, has loss of vision in his right eye due to acute multifocal plaquoid pigment epitheliopathy in 1993. The best corrected visual acuity in his right eye is 20/100 and in the left, 20/20. Following an examination in 2007, his ophthalmologist noted, ''It is my medical opinion that Karl Weinert has sufficient vision to perform driving tasks required to operate any commercial vehicle.'' Mr. Weinert reported that he has driven straight trucks for 21 years, accumulating 945,000 miles. He holds a Class A CDL from New York. His driving record for the last 3 years shows no crashes and no convictions for moving violation in a CMV.

*Ricky L. Wiginton*

Mr. Wiginton, 39, has loss of vision in his right eye due to a traumatic injury sustained as a child. The best corrected visual acuity in his right eye is hand-movement vision and in the left, 20/20. Following an examination in 2006, his ophthalmologist noted, ''At this time his visual acuity is stable, and he has sufficient vision to perform the driving tasks required to operate a commercial vehicle as long as he meets the criteria that you have set forth for allowing him to do so.'' Mr. Wiginton reported that he has driven straight trucks for 12 years, accumulating 1.2 million miles, and tractor-trailer combinations for 8 years, accumulating 880,000 miles. He holds a Class A CDL from Texas. His driving record for the last 3 years shows no crashes and one conviction for a moving violation, speeding in a CMV. He exceeded the speed limit by 8 mph.

*Kevin W. Wunderlin*

Mr. Wunderlin, 51, has loss of vision in his left eye due to a retinal detachment sustained in 1977. The best corrected visual acuity in his right eye is 20/20 and in the left, 20/60. Following an examination in 2007, his optometrist noted, ''In my opinion, Mr. Kevin Wunderlin is able to operate a commercial vehicle (as he has in Ohio the past year with this condition) and as he has done the past 20 years since his retinal detachment in the left eye.'' Mr. Wunderlin reported that he has driven straight trucks for 5 years, accumulating 125,000 miles, and tractor-trailer combinations for 15 years, accumulating 1.1 million miles. He holds a Class A CDL from Ohio. His driving record for the last 3 years shows no crashes and no convictions for moving violations in a CMV.

**Request for Comments**

In accordance with 49 U.S.C. 31136(e) and 31315, FMCSA requests public comment from all interested persons on the exemption petitions described in this notice. The Agency will consider all comments received before the close of business August 20, 2007. Comments will be available for examination in the docket at the location listed under the **ADDRESSES** section of this notice. The Agency will file comments received after the comment closing date in the public docket, and will consider them to the extent practicable. In addition to late comments, FMCSA will also continue to file, in the public docket, relevant information that becomes available after the comment closing date. Interested persons should monitor the public docket for new material.

Issued on: July 13, 2007,

**Pamela M. Pelcovits,**

*Acting Associate Administrator for Policy and Program Development.*

[FR Doc. E7–14034 Filed 7–19–07; 8:45 am]

**BILLING CODE 4910–EX–P**

---

## DEPARTMENT OF TRANSPORTATION

### Federal Railroad Administration

### Proposed Agency Information Collection Activities; Comment Request

**AGENCY:** Federal Railroad Administration, DOT.

**ACTION:** Notice.

**SUMMARY:** In accordance with the Paperwork Reduction Act of 1995 and its implementing regulations, the Federal Railroad Administration (FRA) hereby announces that it is seeking renewal of the following currently approved information collection activities. Before submitting these information collection requirements for clearance by the Office of Management and Budget (OMB), FRA is soliciting public comment on specific aspects of the activities identified below.

**DATES:** Comments must be received no later than September 18, 2007.

**ADDRESSES:** Submit written comments on any or all of the following proposed activities by mail to either: Mr. Robert Brogan, Office of Safety, Planning and Evaluation Division, RRS–21, Federal Railroad Administration, 1120 Vermont Ave., NW., Mail Stop 17, Washington, DC 20590, or Ms. Gina Christodoulou, Office of Support Systems Staff, RAD–43, Federal Railroad Administration, 1120 Vermont Ave., NW., Mail Stop 35, Washington, DC 20590. Commenters requesting FRA to acknowledge receipt of their respective comments must include a self-addressed stamped postcard stating, ''Comments on OMB control number 2130–0524. Alternatively, comments may be transmitted via facsimile to (202) 493–6230 or (202) 493–6170, or via e-mail to Mr. Brogan at *robert.brogan@dot.gov,* or to Ms. Christodoulou at *gina.christodoulou@dot.gov.* Please refer to the assigned OMB control number in any correspondence submitted. FRA will summarize comments received in response to this notice in a subsequent notice and include them in its information collection submission to OMB for approval.

**FOR FURTHER INFORMATION CONTACT:** Mr. Robert Brogan, Office of Safety, Planning and Evaluation Division, RRS–21, Federal Railroad Administration, 1120 Vermont Ave., NW., Mail Stop 25, Washington, DC 20590 (telephone: (202) 493–6292) or Ms. Gina Christodoulou, Office of Support Systems Staff, RAD–43, Federal Railroad Administration, 1120 Vermont Ave., NW., Mail Stop 35, Washington, DC 20590 (telephone: (202) 493–6139). (These telephone numbers are not toll-free.)

**SUPPLEMENTARY INFORMATION:** The Paperwork Reduction Act of 1995 (PRA), Public Law 104–13, section 2, 109 Stat. 163 (1995) (codified as revised at 44 U.S.C. 3501–3520), and its implementing regulations, 5 CFR Part 1320, require Federal agencies to provide 60-days notice to the public for comment on information collection activities before seeking approval for reinstatement or renewal by OMB. 44 U.S.C. 3506(c)(2)(A); 5 CFR 1320.8(d)(1), 1320.10(e)(1), 1320.12(a). Specifically, FRA invites interested respondents to comment on the following summary of proposed information collection activities regarding (i) whether the information collection activities are necessary for FRA to properly execute its functions, including whether the activities will have practical utility; (ii) the accuracy of FRA's estimates of the burden of the information collection activities, including the validity of the methodology and assumptions used to determine the estimates; (iii) ways for FRA to enhance the quality, utility, and clarity of the information being collected; and (iv) ways for FRA to minimize the burden of information collection activities on the public by automated, electronic, mechanical, or other technological collection techniques or other forms of information technology (*e.g.*, permitting electronic submission of responses). *See* 44 U.S.C. 3506(c)(2)(A)(I)–(iv); 5 CFR 1320.8(d)(1)(I)–(iv). FRA believes that soliciting public comment will promote its efforts to reduce the administrative and paperwork burdens associated with the collection of information mandated by Federal regulations. In summary, FRA reasons that comments received will advance three objectives: (i) Reduce reporting burdens; (ii) ensure that it organizes information collection requirements in a ''user friendly'' format to improve the use of such information; and (iii) accurately assess the resources expended to retrieve and produce information requested. *See* 44 U.S.C. 3501.

Below is a brief summary of the currently approved information collection activities that FRA will submit for clearance by OMB as required under the PRA:

*Title:* Radio Communications.

*OMB Control Number:* 2130–0524.

*Abstract:* The Federal Railroad Administration (FRA) amended its radio standards and procedures to promote compliance by making the regulations more flexible; to require wireless communications devices, including radios, for specified classifications of railroad operations and roadway workers; and to re-title this part to reflect its coverage of other means of wireless communications such as cellular telephones, data radio terminals, and other forms of wireless communications to convey emergency and need-to-know information. The new rule establishes safe, uniform procedures covering the use of radio and other wireless communications within the railroad industry.

*Form Number(s):* N/A.

*Affected Public:* Businesses.

*Respondent Universe:* 685 railroads.

*Frequency of Submission:* On occasion; annually.

*Reporting Burden:*

| CFR Section | Respondent universe | Total annual responses | Average time per response | Total annual burden hours | Total annual burden cost |
|---|---|---|---|---|---|
| 220.8—Waivers | 685 railroads | 2 letters | 60 minutes | 2 hours | $78 |
| 220.25—Instruction of Employees. | 685 railroads | 70,000 sessions | 30 minutes | 35,000 hours | 1,120,000 |
| —Sub. Yrs.-Instr. | 685 railroads | 12,540 sessions | 30 minutes | 6,270 hours | 200,640 |
| —Operational Testing of Empl. | 685 railroads | 100,000 tests | 15 minutes | 25,000 hours | 800,000 |
| 220.35—Testing Radio/Wireless Communication Eq. | 685 railroads | 780,000 tests | 30 seconds | 6,500 hours | 208,000 |
| 220.61—Transmission of Mandatory Dir. | 685 railroads | 7,200,000 directives | 1.5 minutes | 180,000 hours | 5,760,000 |
| —Marking Man. Dir | 685 railroads | 624,000 marks | 15 seconds | 2,600 hours | 83,200 |

*Total Responses:* 8,786,542.

*Estimated Total Annual Burden:* 255,372 hours.

*Status:* Regular review.

Pursuant to 44 U.S.C. 3507(a) and 5 CFR 1320.5(b), 1320.8(b)(3)(vi), FRA informs all interested parties that it may not conduct or sponsor, and a respondent is not required to respond to, a collection of information unless it displays a currently valid OMB control number.

**Authority:** 44 U.S.C. 3501–3520.

Issued in Washington, DC on July 16, 2007.

**D.J. Stadtler,**

*Director, Office of Budget, Federal Railroad Administration.*

[FR Doc. E7–14025 Filed 7–19–07; 8:45 am]

BILLING CODE 4910–06–P

## DEPARTMENT OF TRANSPORTATION

### Maritime Administration

**[Docket No. MARAD 2007 28752]**

### Information Collection Available for Public Comments and Recommendations

**ACTION:** Notice and request for comments.

**SUMMARY:** In accordance with the Paperwork Reduction Act of 1995, this notice announces the Maritime Administration's (MARAD's) intention to request extension of approval for three years of a currently approved information collection.

**DATES:** Comments should be submitted on or before September 18, 2007.

**FOR FURTHER INFORMATION CONTACT:** Rodney McFadden, Maritime Administration, 1200 New Jersey Avenue, SE., Washington, DC 20590. Telephone: (202) 366–2647; or e-mail: *Rodney.mcfadden@dot.gov.* Copies of this collection can also be obtained from that office.

**SUPPLEMENTARY INFORMATION:**

*Title of Collection:* Supplementary Training Course Application.

*Type of Request:* Extension of currently approved information collection.

*OMB Control Number:* 2133–0030.

*Form Numbers:* MA–823.

*Expiration Date of Approval:* Three years from date of approval by the Office of Management and Budget.

*Summary of Collection of Information:* Section 1305(a) of the Maritime Education and Training Act of 1980 indicates that the Secretary of Transportation may provide maritime-related training to merchant mariners of the United States and to individuals preparing for a career in the merchant marine of the United States. Also, the U.S. Coast Guard requires a fire-fighting certificate for U.S. merchant marine officers. This collection provides the information necessary for the maritime schools to plan their course offerings and for applicants to complete their certificate requirements.

*Need and Use of the Information:* This information collection is necessary for eligibility assessment, enrollment, attendance verification and recordation. Without this information, the courses would not be documented for future reference by the program or individual student.

*Description of Respondents:* U.S. Merchant Marine Seamen, both officers and unlicensed personnel, and other U.S. citizens employed in other areas of waterborne commerce.

*Annual Responses:* 500.

*Annual Burden:* 25 hours.

*Comments:* Comments should refer to the docket number that appears at the top of this document. Written comments may be submitted to the Docket Clerk, U.S. DOT Dockets, Room W12–140, 1200 New Jersey Avenue, SE., Washington, DC 20590. Comments also may be submitted by electronic means via the Internet at: *http://dms.dot.gov/submit.* Specifically address whether this information collection is necessary for proper performance of the functions of the agency and will have practical utility, accuracy of the burden estimates, ways to minimize this burden, and ways to enhance the quality, utility, and clarity of the information to be collected. All comments received will be available for examination at the above address between 10 a.m. and 5 p.m. EDT (or EST), Monday through Friday, except Federal Holidays. An electronic version of this document is available on the World Wide Web at: *http://dms.dot.gov.*

*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://dms.dot.gov.*

**Authority:** 49 CFR 1.66.

Dated: July 16, 2007.

By Order of the Maritime Administrator.

**Daron T. Threet,**

*Secretary, Maritime Administration.*

[FR Doc. E7–14075 Filed 7–19–07; 8:45 am]

BILLING CODE 4910–81–P

## DEPARTMENT OF TRANSPORTATION

### National Highway Traffic Safety Administration

**[U.S. DOT Docket Number NHTSA–2007–28654]**

### Reports, Forms, and Recordkeeping Requirements

**AGENCY:** National Highway Traffic Safety Administration (NHTSA), Department of Transportation.

**ACTION:** Request for public comment on proposed collection of information.

**SUMMARY:** Before a Federal agency can collect certain information from the public, it must receive approval from the Office of Management and Budget (OMB). Under procedures established by the Paperwork Reduction Act of 1995, before seeking OMB approval, Federal agencies must solicit public comment on proposed collections of information, including extensions and reinstatement of previously approved collections.

This document describes one collection of information for which NHTSA intends to seek OMB approval.

**DATES:** Comments must be received on or before September 18, 2007.

**ADDRESSES:** Comments must refer to the docket notice numbers cited at the beginning of this notice and be submitted to Docket Management, Room W12–140, 1200 New Jersey Avenue, SE., Washington, DC 20590. Please identify the proposed collection of information for which a comment is provided, by referencing its OMB clearance Number. It is requested, but not required, that 2 copies of the comment be provided. The Docket Section is open on weekdays from 10 a.m. to 5 p.m.

**FOR FURTHER INFORMATION CONTACT:** Complete copies of each request for collection of information may be obtained at no charge from Marie Walz, NHTSA 1200 New Jersey Avenue, SE., W53–436, NPO–131, Washington, DC 20590.

Ms.Walz's telephone number is (202) 366–5377. Please identify the relevant collection of information by referring to its OMB Control Number.

**SUPPLEMENTARY INFORMATION:** Under the Paperwork Reduction Act of 1995, before an agency submits a proposed collection of information to OMB for approval, it must first publish a document in the **Federal Register** providing a 60-day comment period and otherwise consult with members of the public and affected agencies concerning each proposed collection of information. The OMB has promulgated regulations describing what must be included in such a document. Under OMB's regulation (at 5CFR 1320.8(d), an agency must ask for public comment on the following:

(i) 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) 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) How to enhance the quality, utility, and clarity of the information to be collected;

(iv) How to minimize the burden of the collection of information on those who are to respond, including the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, e.g. permitting electronic submission of responses.

In compliance with these requirements, NHTSA asks for public comments on the following proposed collections of information:

*Title:* Evaluation of State Motorcycle Safety Programs.

*Affected Public:* The data are to be collected from State employees, in each State the State Motorcycle Safety Administrator and/or an employee of the State Highway Safety Office.

Those benefiting from the data include motorcycle riders, traffic safety advocates, law enforcement groups, as well as the State Motorcycle Safety Administrator's Offices and State Highway Safety Offices.

*Abstract:* NHTSA will conduct a survey of State Motorcycle Safety Administrators and/or State Highway Safety Offices in all 50 States and the District of Columbia to gather data on state-level motorcycle safety programs. This survey will consist of a questionnaire in mail (paper and pencil) format, which will allow a telephone follow-up for further details as necessary. The study will use the State Motorcycle Safety Administrator and State Highway Safety Office survey to gather comprehensive data on what each of the 50 States and the District of Columbia are doing to promote and ensure safe riding behavior.

*Estimated Annual Burden:* Estimated hour burden is 25.5 hours. There is no additional monetary cost associated with this data collection.

*Number of Respondents:* 44 (Estimated).

*Comments are invited on:* 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; 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.

**Joseph S. Carra,**

*Associate Administrator for National Center for Statistics and Analysis.*

[FR Doc. E7–14026 Filed 7–19–07; 8:45 am]

**BILLING CODE 4910–59–P**

## DEPARTMENT OF TRANSPORTATION

### National Highway Traffic Safety Administration

**[U.S. DOT Docket Number NHTSA–2007–28138]**

### Reports, Forms, and Recordkeeping Requirements

**AGENCY:** National Highway Traffic Safety Administration (NHTSA), Department of Transportation.

**ACTION:** Request for extension of a currently approved collection of information.

**SUMMARY:** Before a Federal agency can collect certain information from the public, it must receive approval from the Office of Management and Budget (OMB). Under procedures established by the Paperwork Reduction Act of 1995, before seeking OMB approval, Federal agencies must solicit public comment on proposed collections of information, including extensions and reinstatement of previously approved collections.

This document describes one collection of information for which NHTSA intends to seek OMB approval.

**DATES:** Comments must be received on or before September 18, 2007.

**ADDRESSES:** Comments must refer to the docket notice numbers cited at the beginning of this notice and be submitted to Docket Management, 1200 New Jersey Avenue, SE., West Building Ground Floor, Room W12–140, Washington, DC 20590 by any of the following methods.

- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the instructions for submitting comments.
- *Agency Web site: http://dms.dot.gov.* Follow the instructions for submitting comments on the Docket Management System.
- *Fax:* (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.
- *Hand Delivery/Courier:* 1200 New Jersey Avenue, SE., West Building Ground Floor, Room W12–140, Washington, DC 20590, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. Telephone: 1–800–647–5527.

*Instructions:* All submissions must include the agency name and docket number for this proposed collection of information. Note that all comments received will be posted without change to *http://dms.dot.gov* including any personal information provided.

*Docket:* For access to the docket to read background documents or comments received, go to *http://dms.dot.gov* at any time or to Room W12–140 on the ground level of the DOT Building, 1200 New Jersey Avenue, SE., West Building Ground Floor, Washington, DC, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

**FOR FURTHER INFORMATION CONTACT:** Complete copies of each request for collection of information may be obtained at no charge from Hisham T. Mohamed, NHTSA, 1200 New Jersey Avenue, SE., West Building, Room W43–437 (fourth floor), NVS–131, Washington, DC 20590. Mr. Mohamed's telephone number is (202) 366–0307. Please identify the relevant collection of information by referring to its OMB Control Number.

**SUPPLEMENTARY INFORMATION:** Under the Paperwork Reduction Act of 1995, before an agency submits a proposed collection of information to OMB for approval, it must first publish a document in the **Federal Register** providing a 60-day comment period and otherwise consult with members of the public and affected agencies concerning each proposed collection of information.

The OMB has promulgated regulations describing what must be included in such a document. Under OMB's regulation (at 5 CFR 1320.8(d)), an agency must ask for public comment on the following:

(i) 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) 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) How to enhance the quality, utility, and clarity of the information to be collected;

(iv) How to minimize the burden of the collection of information on those who are to respond, including the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, e.g. permitting electronic submission of responses.

In compliance with these requirements, NHTSA asks for public comments on the following proposed collections of information:

*Title:* 49 CFR part 575, 104; Uniform Tire Quality Grading Standard.

*OMB Control Number:* 2127–0519.

*Affected Public:* All passenger car tire manufacturers and brand name owners offering passenger car tires for sale in the United States.

*Form Number:* The collection of this information uses no standard form.

*Abstract:* Part 575 requires tire manufacturers and tire brand owners to submit reports to NHTSA regarding the UTQGS grades of all passenger car tire lines they offer for sale in the United States. This information is used by consumers of passenger car tires to compare tire quality in making their purchase decisions. The information is provided in several different ways to insure that the consumer can readily see and understand the tire grade: (1) The grades are molded into the sidewall of the tire so that they can be reviewed on both the new tire and the old tire that is being replaced; (2) a paper label is affixed to the tread face of the new tire that provides the grade of that particular tire line along with an explanation of the grading system; (3) tire manufacturers provide dealers with brochures for public distribution listing the grades of all of the tirelines they offer for sale; and (4) NHTSA compiles the grading information of all manufacturers' tirelines into a booklet that is available to the public both in printed form and on the Web site.

*Estimated Annual Burden:* NHTSA estimates that a total of 89,730 man-hours are required to write the brochures, engrave the new passenger car tire molds, and affix the paper labels to the tires. Based on an average hourly rate of $22 per hour for rubber workers in the United States, the cost to the manufacturers is $1,974,060 to perform those items listed above. The largest portion of the cost burden imposed by the UTQGS program arises from the testing necessary to determine the grades that should be assigned to the tires. An average of 125 convoys, driven 7,200 miles each, consisting of four vehicles and four drivers, are run each year for treadwear testing. NHTSA estimates it cost $0.60 per vehicle mile including salaries, overhead and reports. This brings the annual treadwear testing cost to $2,160,000. For the traction testing, it is estimated that 1,900 tires are tested annually with an estimated cost of $38,000 for use of the government test facility. Using a factor of 3.5 times to cover salary and overhead of test contractors, the estimated cost of traction testing is $133,000. A separate temperature grade testing for tires is required, since the test will not be an extension of the high speed performance test of 49 CFR 571.109 which is required for safety certification. Section 571.109 is replaced by § 571.139, which has different test speeds. For the temperature testing, it is estimated that 1,900 tires are tested annually with an estimated average cost per test of $423. Therefore, the estimated UTQGS temperature annual testing is $803,700. Thus the total estimated cost for UTQGS testing is $3,096,700. The cost of printing the tread labels is approximately 21,890,000 and estimate for printing brochures is at $999,000. This yields a total annual financial burden of approximately $25,985,700 (approximately $26 million) on the tire manufacturers.

*Estimated Annual Burden to the Government:* The estimated annual cost of UTQGS to the Federal government is $1,278,000. The cost consists of approximately $152,000 for data management $730,000 for enforcement testing, and about $396,000 for general administration of the program.

*Number of Respondents:* There are approximately 163 individual tire brands sold in the United States. The actual number of respondents is much less than 163 due to company acquisitions, mergers, and in most cases, the manufacturer will report for the various individual brand names that they produce tires for. The actual number of respondents is about 65 individual responses.

*Comments are invited on:* 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; 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.

Issued on: July 16, 2007.

**Stephen R. Kratzke,**

*Associate Administrator for Rulemaking.*

[FR Doc. E7–14094 Filed 7–19–07; 8:45 am]

**BILLING CODE 4910–59–P**

---

## DEPARTMENT OF TRANSPORTATION

### National Highway Traffic Safety Administration

### Petition for Exemption From the Vehicle Theft Prevention Standard; Mercedes-Benz

**AGENCY:** National Highway Traffic Safety Administration (NHTSA), Department of Transportation (DOT).

**ACTION:** Grant of petition for exemption.

**SUMMARY:** This document grants in full the Mercedes-Benz USA, LLC.'s, (MBUSA) petition for exemption of the C-Line Chassis vehicle line in accordance with 49 CFR part 543, *Exemption from the Theft Prevention Standard.* This petition is granted because the agency has determined that the antitheft device to be placed on the line as standard equipment is likely to be as effective in reducing and deterring motor vehicle theft as compliance with the parts-marking requirements of the Theft Prevention Standard (49 CFR part 541).

**DATES:** The exemption granted by this notice is effective beginning with model year (MY) 2008.

**FOR FURTHER INFORMATION CONTACT:** Ms. Carlita Ballard, Office of International Vehicle, Fuel Economy and Consumer Standards, NHTSA, 1200 New Jersey Avenue, SE., NVS–131, Room W43–439 (4th Floor), Washington, DC 20590. Ms. Ballard's phone number is (202) 366–5222. Her fax number is (202) 493–2990.

**SUPPLEMENTARY INFORMATION:** In a petition dated August 8, 2006, MBUSA requested exemption from the parts-marking requirements of the theft prevention standard (49 CFR part 541) for the C-Line Chassis vehicle line, beginning with the 2008 model year. The petition has been filed pursuant to 49 CFR part 543, *Exemption from Vehicle Theft Prevention Standard*, based on the installation of an antitheft device as standard equipment for an entire vehicle line.

Under § 543.5(a), a manufacturer may petition NHTSA to grant exemptions for one line of its vehicle lines per model year. In its petition, MBUSA provided a detailed description and diagram of the identity, design, and location of the components of the antitheft device for the C-Line Chassis vehicle line. MBUSA stated that all C-Line Chassis vehicles will be equipped with a passive, transponder-based electronic immobilizer device as standard equipment beginning with MY 2008. Features of the antitheft device will include an electronic key, a passive immobilizer system (FBS III) which includes an electronic ignition starter switch control unit (EIS) and an engine control unit (ECU). The device will also have a visible and audible alarm. The alarm system will provide protection for all four doors, the trunk and the engine hood. If any of the protected areas are violated, the four turn signal lamps and the left and right side turn signal marker lamps will flash, the interior lamps will switch on and the alarm will sound. MBUSA's submission is considered a complete petition as required by 49 CFR 543.7, in that it meets the general requirements contained in § 543.5 and the specific content requirements of § 543.6.

MBUSA stated that the transmitter key, the electronic ignition starter switch control unit and the engine control unit will work collectively to perform the immobilizer function. The immobilizer will prevent the engine from running unless a valid key is used in the ignition switch. Immobilization is activated when the key is removed from the ignition switch, whether the doors are open or closed. Once activated, a valid, coded-key must be inserted into the ignition switch to disable immobilization and permit the vehicle to start.

In addressing the specific content requirements of § 543.6, MBUSA provided information on the reliability and durability of its proposed device. To ensure reliability and durability of the device and to verify its ability to satisfactory perform under extreme conditions, MBUSA conducted various tests based on its own specified standards. MBUSA provided a detailed list of the various tests conducted and believes that the device is reliable and durable since the device complied with its own specific test conditions.

MBUSA also compared the device proposed for its vehicle line with other devices which NHTSA has determined to be as effective in reducing and deterring motor vehicle theft as would compliance with the parts-marking requirements. MBUSA stated that its proposed device is functionally equivalent to the systems used in the S-Line Chassis and E-Line Chassis vehicles which the agency has granted exemptions from the parts-marking requirements of the theft prevention standard. MBUSA concluded that the antitheft device for its C-Line Chassis vehicle line is no less effective than those devices in lines for which NHTSA has already granted full exemption.

On the basis of this comparison, MBUSA informed the agency that the C-Line Chassis vehicle line was first introduced as a model year 1994 vehicle. MBUSA stated that based on NHTSA's theft rates from 1994 to 2004, the average theft rate of the C-Line Chassis vehicles without the immobilizer was 1.6437 (CY 1994–1997) and 1.4167 after installation of the immobilizer device. MBUSA concluded that the data indicates that the immobilizer was effective in contributing to the theft rate reduction for its C-Line Chassis vehicles.

Pursuant to 49 U.S.C. 33106 and 49 CFR 543.7(b), the agency grants a petition for an exemption from the parts-marking requirements of part 541 either in whole or in part, if it determines that, based upon substantial evidence, the standard equipment antitheft device is likely to be as effective in reducing and deterring motor vehicle theft as compliance with the parts-marking requirements of part 541. The agency finds that MBUSA has provided adequate reasons for its belief that the antitheft device will reduce and deter theft. This conclusion is based on the information MBUSA provided about its device.

The agency concludes that the device will provide the five types of performance listed in § 543.6(a)(3): Promoting activation; attracting attention to the efforts of unauthorized persons to enter or operate a vehicle by means other than a key; preventing defeat or circumvention of the device by unauthorized persons; preventing operation of the vehicle by unauthorized entrants; and ensuring the reliability and durability of the device. The agency agrees that the device is substantially similar to devices in other vehicles lines for which the agency has already granted exemptions. In addition, the theft rate has reduced since the installation of this device on the line.

For the foregoing reasons, the agency hereby grants in full MBUSA's petition for exemption for the vehicle line from the parts-marking requirements of 49 CFR Part 541. The agency notes that 49 CFR Part 541, Appendix A–1, identifies those lines that are exempted from the Theft Prevention Standard for a given model year. 49 CFR 543.7(f) contains publication requirements incident to the disposition of all Part 543 petitions. Advanced listing, including the release of future product nameplates, the beginning model year for which the petition is granted and a general description of the antitheft device is necessary in order to notify law enforcement agencies of new vehicle lines exempted from the parts-marking requirements of the Theft Prevention Standard.

If MBUSA decides not to use the exemption for this line, it must formally notify the agency, and, thereafter, the line must be fully marked as required by 49 CFR 541.5 and 541.6 (marking of major component parts and replacement parts).

NHTSA notes that if MBUSA wishes in the future to modify the device on which this exemption is based, the company may have to submit a petition to modify the exemption. Section 543.7(d) states that a Part 543 exemption applies only to vehicles that belong to a line exempted under this part and equipped with the anti-theft device on which the line's exemption is based. Further, § 543.9(c)(2) provides for the submission of petitions "to modify an exemption to permit the use of an antitheft device similar to but differing from the one specified in that exemption."

The agency wishes to minimize the administrative burden that § t 543.9(c)(2) could place on exempted vehicle manufacturers and itself. The agency did not intend Part 543 to require the submission of a modification petition for every change to the components or design of an antitheft device. The significance of many such changes could be *de minimis*. Therefore, NHTSA suggests that if the manufacturer contemplates making any changes the effects of which might be characterized as *de minimis*, it should consult the agency before preparing and submitting a petition to modify.

**Authority:** 49 U.S.C. 33106; delegation of authority at 49 CFR 1.50.

Issued on: July 16, 2007.

**Stephen R. Kratzke,**

*Associate Administrator for Rulemaking.*

[FR Doc. E7–14093 Filed 7–19–07; 8:45 am]

BILLING CODE 4910–59–P

## DEPARTMENT OF TRANSPORTATION

### Pipeline and Hazardous Materials Safety Administration Office of Hazardous Materials Safety; Notice of Application for Special Permits

**AGENCY:** Pipeline and Hazardous Materials Safety Administration (PHMSA), DOT.

**ACTION:** List of Applications for Special Permits.

**SUMMARY:** In accordance with the procedures governing the application for, and the processing of, special permits from the Department of Transportation's Hazardous Material Regulations (49 CFR Part 107, Subpart B), notice is hereby given that the Office of Hazardous Materials Safety has received the application described herein. Each mode of transportation for which a particular special permit is requested is indicated by a number in the "Nature of Application" portion of the table below as follows: 1—Motor vehicle, 2—Rail freight, 3—Cargo vessel, 4—Cargo aircraft only, 5—Passenger-carrying aircraft.

**DATES:** Comments must be received on or before August 20, 2007.

*Address Comments To:* Record Center, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, Washington, DC 20590.

Comments should refer to the application number and be submitted in triplicate. If confirmation of receipt of comments is desired, include a self-addressed stamped postcard showing the special permit number.

**FOR FURTHER INFORMATION CONTACT:** Copies of the applications are available for inspection in the Records Center, Nassif Building, 400 7th Street, SW., Washington, DC or at *http://dms.dot.gov.*

This notice of receipt of applications for special permit is published in accordance with Part 107 of the Federal hazardous materials transportation law (49 U.S.C. 5117(b); 49 CFR 1.53(b)).

Issued in Washington, DC, on July 11, 2007.

**Delmer Billings,**

*Director, Special Permits & Approvals Programs, Office of Hazardous Materials, Special Permits & Approvals.*

NEW SPECIAL PERMITS

| Application No. | Docket No. | Applicant | Regulation(s) affected | Nature of special permits thereof |
|---|---|---|---|---|
| 14527–N | | FedEx Express, Memphis, TN. | 49 CFR 175.33 | To authorize the air transportation of certain hazardous materials without identifying the packaging type on the Notification to Pilot in Command. (modes 4, 5) |
| 14528–N | | Halpern Import Company, Inc., Atlanta, GA. | 49 CFR 173.304; 173.306 | |
| 14532–N | | Degussa Corporation, Parsippany, NJ. | 49 CFR 173.31(d)(1)(vi); 172.302(c). | To authorize the transportation in commerce of certain Division 5.1 hazardous materials in tank cars that have not had their rupture disk removed for inspection. (mode 2) |
| 14534–N | | American Airlines, Inc., Tulsa, OK. | 49 CFR 73.302a(a)(2) | To authorize the transportation in commerce of DOT Specification 3HT cylinders beyond the 24 year service life provided they pass the applicable retest requirements every two years. (modes 1, 2, 3, 4, 5) |
| 14535–N | | Environmental Packaging Technologies, Houston, TX. | 49 CFR 172.102(c) special provision IB2 and IB3. | To authorize the transportation in commerce of certain hazardous materials with a vapor pressure of 150 kPa at 55 °C in intermediate bulk containers. (mode 1) |
| 14542–N | | The University of Texas at Austin, Austin, TX. | 49 CFR 173.420 | To authorize the one-way transportation in commerce of approximately 1 pound of natural uranium hexafluoride in a DOT Specification 4B240ET cylinder by motor vehicle. (mode 1) |

[FR Doc. 07–3542 Filed 7–19–07; 8:45 am]
BILLING CODE 4909–60–M

## DEPARTMENT OF TRANSPORTATION

### Pipeline and Hazardous Materials Safety Administration

### Office of Hazardous Materials Safety; Notice of Delays in Processing of Special Permits Applications

**AGENCY:** Pipeline and Hazardous Materials Safety Administration (PHMSA), DOT.

**ACTION:** List of applications delayed more than 180 days.

**SUMMARY:** In accordance with the requirements of 49 U.S.C. 5117(c), PHMSA is publishing the following list of special permit applications that have been in process for 180 days or more. The reason(s) for delay and the expected completion date for action on each application is provided in association with each identified application.

**FOR FURTHER INFORMATION CONTACT:** Delmer F. Billings, Director, Office of Hazardous Materials Special Permits and Approvals, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, East Building, PHH–30, 1200 New Jersey Avenue, Southeast, Washington, DC 20590–0001, (202) 366–4535.

### Key to "Reason for Delay"

1. Awaiting additional information from applicant.
2. Extensive public comment under review.
3. Application is technically complex and is of significant impact or precedent-setting and requires extensive analysis.
4. Staff review delayed by other priority issues or volume of special permit applications.

### Meaning of Application Number Suffixes

N—New application.

M—Modification request.

PM—Party to application with modification request.

Issued in Washington, DC, on July 16, 2007.

**Delmer F. Billings,**

*Director, Office of Hazardous Materials, Special Permits and Approvals.*

MODIFICATION TO SPECIAL PERMITS

| Application number | Applicant | Reason for delay | Estimated date of completion |
|---|---|---|---|
| 10481–M | M–1 Engineering Limited Bradfrod, West Yorkshire | 4 | 09–30–2007 |
| 114167–M | Trinityrail Dallas, TX | 1,3,4 | 09–30–2007 |

NEW SPECIAL PERMIT APPLICATIONS

| Application number | Applicant | Reason for delay | Estimated date of completion |
|---|---|---|---|
| 14385–N | Kansas City Southern Railway Company Kansas City, MO | 4 | 09–30–2007 |
| 14442–N | Trinityrail Dallas, TX | 4 | 09–30–2007 |
| 14468–N | REC Advanced Silicon Materials LLC Butte, MT | 4 | 09–30–2007 |
| 14470–N | Marsulex, Inc. Springfield, OR | 4 | 08–31–2007 |
| 14469–N | Space Systems/Loral Palo Alto, CA | 4 | 07–31–2007 |

NEW SPECIAL PERMIT APPLICATIONS—Continued

| Application number | Applicant | Reason for delay | Estimated date of completion |
|---|---|---|---|
| 14457–N | Ambrol Alfa Metalomecanica SA Portugal | 4 | 09–30–2007 |
| 14436–N | BNSF Railway Company Topeka, KS | 4 | 09–30–2007 |
| 14402–N | Lincoln Composites Lincoln, NE | 1 | 12–31–2007 |

[FR Doc. 07–3543 Filed 7–19–07; 8:45 am]

BILLING CODE 4910–60–M

## DEPARTMENT OF TRANSPORTATION

### Pipeline and Hazardous Materials Safety Administration

### Office of Hazardous Materials Safety; Notice of Applications for Modification of Special Permit

**AGENCY:** Pipeline and Hazardous Materials Safety Administration (PHMSA), DOT.

**ACTION:** List of applications for modification of special permit.

**SUMMARY:** In accordance with the procedures governing the application for, and the processing of, special permits from the Department of Transportation's Hazardous Material Regulations (49 CFR Part 107, Subpart B), notice is hereby given that the Office of Hazardous Materials Safety has received the application described herein. This notice is abbreviated to expedite docketing and public notice. Because the sections affected, modes of transportation, and the nature of application have been shown in earlier **Federal Register** publications, they are not repeated here. Request of modifications of special permits (e.g. to provide for additional hazardous materials, packaging design changes, additional mode of transportation, etc.) are described in footnotes to the application number. Application numbers with the suffix ''M'' denote a modification request. There applications have been separated from the new application for special permits to facilitate processing.

**DATES:** Comments must be received on or before August 6, 2007.

*Address Comments To:* Record Center, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, Washington, DC 20590.

Comments should refer to the application number and be submitted in triplicate. If confirmation of receipt of comments is desired, include a self-addressed stamped postcard showing the special permit number.

**FOR FURTHER INFORMATION CONTACT:** Copies of the applications are available for inspection in the Records Center, Nassif Building, 400 7th Street SW., Washington, DC or at *http://dms.dot.gov*.

This notice of receipt of applications for modification of special permit is published in accordance with Part 107 of the Federal hazardous materials transportation law (49 U.S.C. 5117(b); 49 CFR 1.53(b)).

Issued in Washington, DC, on July 9, 2007.

**Delmer Billings,**

*Director, Special Permits & Approvals Programs, Office of Hazardous Materials, Special Permits & Approvals.*

MODIFICATION SPECIAL PERMITS

| Application No. | Docket number | Applicant | Regulation(s) affected | Nature of special permit thereof |
|---|---|---|---|---|
| 5022–M | | Alliant Techsystems, Inc., Elkton, MD. | 49 CFR 174.101(L); 174.104(d); 174.112(a); 177.834(1)(1). | To modify the special permit to authorize the transportation in commerce of additional Division 1.2 hazardous materials. |
| 7657–M | | Welker Engineering Company, Sugar Land, TX. | 49 CFR 173.302(a)(1); 173.304(a)(1); 173.304(b)(1); 175.3; 173.201; 173.202; 173.203. | To modify the special permit to authorize the transportation in commerce of additional Division 2.1 gases and to authorize a change in the material of construction. |
| 10964–M | | Kidde Aerospace & Defense. | 49 CFR | To modify the special permit to authorize |
| 11054–M | | Welker Engineering Company, Sugar Land, TX. | 49 CFR 178.36 Subpart C | To modify the special permit to authorize a change in the material of construction. |
| 11592–M | | Amtrol Inc., West Warwick, RI. | 49 CFR 173.306(g) | To modify the special permit to authorize the transportation in commerce of additional Division 2.2 gases. |
| 12412–M | 1999–5797 | Cincinnati Pool Management, Inc., West Chester, OH. | 49 CFR 177.834(h); 172.203(a); 172.302(c). | To modify the special permit to allow for filling of an IBC without removing it from the motor vehicle on which it is transported while on private property. |
| 12531–M | | Worthington Cylinder Corporation, Columbus, OH. | 49 CFR 173.302(a); 173.304(a); 173.304(d); 178.61(b); 178.61(f); 178.61(g); 178.61(g); 178.61(i); 178.61(k). | To modify the special permit to authorize additional packing groups for already authorized hazardous materials. |
| 13027–M | | Hernco Fabrication & Services, Midland, TX. | 49 CFR 173.241; 173.242 | To modify the special permit to authorize the transportation in commerce of additional Division 3 and 8 hazardous materials in non-DOT specification portable tanks. |

MODIFICATION SPECIAL PERMITS—Continued

| Application No. | Docket number | Applicant | Regulation(s) affected | Nature of special permit thereof |
|---|---|---|---|---|
| 14466–M ..... | ........................ | Alaska Pacific Powder Company, Anchorage, AK. | 49 CFR 172.101 Column (9B). | To modify the special permit to allow the transportation in commerce of additional Class 1 explosive materials which are forbidden for transportation by air, to be transported by cargo aircraft within the State of Alaska when other means of transportation are impracticable or not available. |

[FR Doc. 07–3541 Filed 7–19–07; 8:45 am]
**BILLING CODE 4909–60–M**

## DEPARTMENT OF TRANSPORTATION

### Surface Transportation Board

**[STB Ex Parte No. 670]**

### Establishment of a Rail Energy Transportation Advisory Committee

**AGENCY:** Surface Transportation Board.

**ACTION:** Notice of establishment of Federal Advisory Committee.

**SUMMARY:** As required by section 9(a)(2) of the Federal Advisory Committee Act (FACA), 5 U.S.C. App., the Surface Transportation Board (Board), hereby gives notice that, following consultation with the General Services Administration, the Board is creating a Rail Energy Transportation Advisory Committee (RETAC). RETAC will provide advice and guidance to the Board, and serve as a forum for discussion of emerging issues, regarding the transportation by rail of energy resources, particularly, but not necessarily limited to, coal, ethanol and other biofuels. The Board is also requesting suggestions for candidates for membership on RETAC.

**DATES:** Suggestions of candidates for membership on RETAC are due August 9, 2007.

**ADDRESSES:** Suggestions may be submitted either via the Board's e-filing format or in the traditional paper format. Any person using e-filing should attach a document and otherwise comply with the instructions at the E-FILING link on the Board's Web site, at: *http://www.stb.dot.gov*. Any person submitting a filing in the traditional paper format should send an original and 10 copies to: Surface Transportation Board, Attn: STB Ex Parte No. 670, 395 E Street, SW., Washington, DC 20423–0001.

**FOR FURTHER INFORMATION, CONTACT:** Scott M. Zimmerman at 202–245–0202. [Assistance for the hearing impaired is available through the Federal Information Relay Service (FIRS) at 1–800–877–8339.]

**SUPPLEMENTARY INFORMATION:** The Board, created by Congress in 1996 to take over many of the functions previously performed by the Interstate Commerce Commission, exercises broad authority over transportation by rail carriers, including regulation of railroad rates and service (49 U.S.C. 10701–10747, 11101–11124), as well as the construction, acquisition, operation, and abandonment of rail lines (49 U.S.C. 10901–10907) and railroad line sales, consolidations, mergers, and common control arrangements (49 U.S.C. 10902, 11323–11327).

The Board views the reliability of the nation's energy supply as crucial to this nation's economic and national security, and the transportation by rail of coal and other energy resources as a vital link in the energy supply chain. The Board is establishing RETAC as an advisory committee consisting of a balanced cross-section of energy and rail industry stakeholders to provide independent, candid policy advice to the Board and to foster open, effective communication among the affected interests on issues such as rail performance, capacity constraints, infrastructure planning and development, and effective coordination among suppliers, carriers, and users of energy resources. RETAC shall function solely as an advisory body, and will comply with the provisions of FACA and its implementing regulations.

On March 9, 2007, the Board issued a decision announcing its proposal to establish a rail energy transportation advisory committee and soliciting public comment on the advisability of establishing such a committee, the size and composition of the committee, and the scope of its mandate. In response, comments were received from more than two dozen parties, including rail carriers, energy producers, trade associations, and others. Based on its review of those comments and consultation with the General Services Administration, the Board has decided to establish RETAC and has developed a charter to govern its operation.

RETAC will be balanced and representative of interested and affected parties, and will consist of not less than: 5 representatives from the Class I railroads, 3 representatives from Class II and III railroads, 3 representatives from coal producers, 5 representatives from electric utilities (including at least one rural electric cooperative and one state- or municipally-owned utility), 4 representatives from biofuel refiners, processors, or distributors, or biofuel feedstock growers or providers, and 2 representatives from private car owners, car lessors, or car manufacturers. RETAC may also include up to 3 members with relevant experience but not necessarily affiliated with one of the aforementioned industries or sectors. The Chairman of the Board may invite representatives from the U.S. Departments of Agriculture, Energy and Transportation and the Federal Energy Regulatory Commission to serve on RETAC in advisory capacities as *ex officio* (non-voting) members, and the three members of the Board shall serve as *ex officio* members of the Committee as well.

RETAC will meet at least two times per year; the Board anticipates that RETAC will meet in the fall of 2007. No honoraria, salaries, travel or per diem are available to members of the RETAC; however, reimbursement for travel expenses may be sought from the Board in cases of hardship.

Chairman Nottingham has appointed Scott M. Zimmerman, Acting Director of the Board's Office of Congressional and Public Services, to serve as the Designated Federal Official—the agency's liaison to RETAC. Suggestions for members of RETAC should be submitted in letter form, identifying the name of the candidate; evidence of the interests the candidate will represent; and a representation that the candidate is willing to serve a two-year term as a member of the RETAC. Suggestions for candidates for membership on the RETAC should be submitted to the Board by August 9, 2007.

Copies of the RETAC charter will be available from the Board's contractor, ASAP Document Solutions (mailing address: Suite 103, 9332 Annapolis Rd., Lanham, MD 20706; e-mail address: *asapdc@verizon.net*; telephone number: 202–306–4004). The charter will also be available for viewing and self-copying in the Board's Public Docket Room, Room 131, and will be posted to the Board's Web site at: *http://www.stb.dot.gov*.

This action will not significantly affect either the quality of the human environment or the conservation of energy resources.

**Authority:** 49 U.S.C. 721, 49 U.S.C. 11101; 49 U.S.C. 11121.

Decided: July 13, 2007.

By the Board, Chairman Nottingham, Vice Chairman Buttrey, and Commissioner Mulvey.

**Vernon A. Williams,**

*Secretary.*

[FR Doc. E7–14038 Filed 7–19–07; 8:45 am]

**BILLING CODE 4915–01–P**

## DEPARTMENT OF TRANSPORTATION

### Surface Transportation Board

**[STB Docket No. AB–43 (Sub-No. 179X)]**

### Illinois Central Railroad Company—Abandonment Exemption—in Rankin County, MS

Illinois Central Railroad Company (IC) has filed a notice of exemption under 49 CFR Part 1152 Subpart F—*Exempt Abandonments* to abandon a 2.10-mile line of railroad between milepost 70.20 and milepost 68.10, in Flowood, Rankin County, MS. The line traverses United States Postal Service Zip Code 39232.

IC has certified that: (1) No local traffic has moved over the line for at least 2 years; (2) there is no overhead traffic to be rerouted over other lines; (3) no formal complaint filed by a user of rail service on the line (or by a state or local government entity acting on behalf of such user) regarding cessation of service over the line either is pending with the Board or with any U.S. District Court or has been decided in favor of complainant within the 2-year period; and (4) the requirements of 49 CFR 1105.7 (environmental report), 49 CFR 1105.8 (historic report), 49 CFR 1105.11 (transmittal letter), 49 CFR 1105.12 (newspaper publication), and 49 CFR 1152.50(d)(1) (notice to governmental agencies) have been met.

As a condition to this exemption, any employee adversely affected by the abandonment shall be protected under *Oregon Short Line R. Co.—Abandonment—Goshen,* 360 I.C.C. 91 (1979). To address whether this condition adequately protects affected employees, a petition for partial revocation under 49 U.S.C. 10502(d) must be filed.

Provided no formal expression of intent to file an offer of financial assistance (OFA) has been received, this exemption will be effective on August 21, 2007, unless stayed pending reconsideration. Petitions to stay that do not involve environmental issues,[1] formal expressions of intent to file an OFA under 49 CFR 1152.27(c)(2),[2] and trail use/rail banking requests under 49 CFR 1152.29 must be filed by July 30, 2007. Petitions to reopen or requests for public use conditions under 49 CFR 1152.28 must be filed by August 9, 2007, with the Surface Transportation Board, 395 E Street, SW., Washington, DC 20423–0001.

A copy of any petition filed with the Board should be sent to IC's representative: Thomas J. Healey, 17641 S. Ashland Avenue, Homewood, IL 60430–1345.

If the verified notice contains false or misleading information, the exemption is void *ab initio.*

IC has filed environmental and historic reports which address the effects, if any, of the abandonment on the environment and historic resources. SEA will issue an environmental assessment (EA) by July 27, 2007. Interested persons may obtain a copy of the EA by writing to SEA (Room 1100, Surface Transportation Board, Washington, DC 20423–0001) or by calling SEA, at (202) 245–0305. [Assistance for the hearing impaired is available through the Federal Information Relay Service (FIRS) at 1–800–877–8339.] Comments on environmental and historic preservation matters must be filed within 15 days after the EA becomes available to the public.

Environmental, historic preservation, public use, or trail use/rail banking conditions will be imposed, where appropriate, in a subsequent decision.

Pursuant to the provisions of 49 CFR 1152.29(e)(2), IC shall file a notice of consummation with the Board to signify that it has exercised the authority granted and fully abandoned the line. If consummation has not been effected by IC's filing of a notice of consummation by July 20, 2008, and there are no legal or regulatory barriers to consummation, the authority to abandon will automatically expire.

Board decisions and notices are available on our website at: *http://www.stb.dot.gov.*

Decided: July 10, 2007.

By the Board, David M. Konschnik, Director, Office of Proceedings.

**Vernon A. Williams,**

*Secretary.*

[FR Doc. E7–13759 Filed 7–19–07; 8:45 am]

**BILLING CODE 4915–01–P**

[1] The Board will grant a stay if an informed decision on environmental issues (whether raised by a party or by the Board's Section of Environmental Analysis (SEA) in its independent investigation) cannot be made before the exemption's effective date. *See Exemption of Out-of-Service Rail Lines,* 5 I.C.C.2d 377 (1989). Any request for a stay should be filed as soon as possible so that the Board may take appropriate action before the exemption's effective date.

[2] Each OFA must be accompanied by the filing fee, which is currently set at $1,300. *See* 49 CFR 1002.2(f)(25).

## DEPARTMENT OF THE TREASURY

### Office of the Secretary

### List of Countries Requiring Cooperation With an International Boycott

In order to comply with the mandate of section 999(a)(3) of the Internal Revenue Code of 1986, the Department of the Treasury is publishing a current list of countries which require or may require participation in, or cooperation with, an international boycott (within the meaning of section 999(b)(3) of the Internal Revenue Code of 1986).

On the basis of the best information currently available to the Department of the Treasury, the following countries require or may require participation in, or cooperation with, an international boycott (within the meaning of section 999(b)(3) of the Internal Revenue Code of 1986).

Kuwait

Lebanon

Libya

Qatar

Saudi Arabia

Syria

United Arab Emirates

Yemen, Republic of

Iraq is not included in this list, but its status with respect to future lists remains under review by the Department of the Treasury.

Dated: July 16, 2007.

**John L. Harrington,**

*Acting International Tax Counsel (Tax Policy).*

[FR Doc. 07–3533 Filed 7–19–07; 8:45 am]

**BILLING CODE 4810–25–M**

## DEPARTMENT OF THE TREASURY

### Fiscal Service

### Financial Management Service, Senior Executive Service; Financial Management Service Performance Review Board

**AGENCY:** Financial Management Service, Fiscal Service, Treasury.

**ACTION:** Notice.

**SUMMARY:** This notice announces the appointment of members to the Financial Management Service (FMS) Performance Review Board (PRB).

**DATES:** This notice is effective July 20, 2007.

**FOR FURTHER INFORMATION CONTACT:** Judith R. Tillman, Deputy Commissioner, Financial Management Service, 401 14th Street, SW., Washington, DC; telephone (202) 874–7000.

**SUPPLEMENTARY INFORMATION:** Pursuant to 5 U.S.C. 4314(c)(4), this notice is given of the appointment of individuals to serve as members of the FMS PRB. This Board reviews the performance appraisals of career senior executives below the Assistant Commissioner level and makes recommendations regarding ratings, bonuses, and other personnel actions. Four voting members constitute a quorum. The names and titles of the FMS PRb members are as follows:

**Primary Members**

Judith R. Tillman, Deputy Commissioner.

Rita Bratcher, Assistant Commissioner, Debt Management Services.

Sheryl R. Morrow, Assistant Commissioner, Federal Finance.

Wanda Rogers, Assistant Commissioner, Regional Operations.

Charles R. Simpson, Assistant Commissioner, Information Resources.

D. James Sturgill, Assistant Commissioner, Governmentwide Accounting.

**Alternate Members**

Scott H. Johnson, Assistant Commissioner, Management (Chief Financial Officer).

Janice Lucas, Assistant Commissioner, Financial Operations.

Dated: July 18, 2007.

**Judith R. Tillman,**

*Deputy Commissioner.*

[FR Doc. 07–3531 Filed 7–19–07; 8:45 am]

**BILLING CODE 4810–35–M**

## DEPARTMENT OF THE TREASURY

### Internal Revenue Service

### Proposed Collection; Comment Request for Form 8851

**AGENCY:** Internal Revenue Service (IRS), Treasury.

**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 IRS is soliciting comments concerning Form 8851, Summary of Archer MSAs.

**DATES:** Written comments should be received on or before September 18, 2007 to be assured of consideration.

**ADDRESSES:** Direct all written comments to R. Joseph Durbala, Internal Revenue Service, room 6516, 1111 Constitution Avenue, NW., Washington, DC 20224.

**FOR FURTHER INFORMATION CONTACT:** Requests for additional information or copies of the form and instructions should be directed to Allan Hopkins, at (202) 622–6665, or at Internal Revenue Service, room 6407, 1111 Constitution Avenue, NW., Washington, DC 20224, or through the Internet, at *Allan.M.Hopkins@irs.gov.*

**SUPPLEMENTARY INFORMATION:**

*Title:* Summary of Archer MSAs.

*OMB Number:* 1545–1743.

*Form Number:* 8851.

*Abstract:* Internal Revenue Code section 220(j)(4) requires trustees, who establish medical savings accounts, to report the following: (a) Number of medical savings accounts established before July 1 of the taxable year (beginning January 1, 2001), (b) name and taxpayer identification number of each account holder and, (c) number of accounts which are accounts of previously uninsured individuals. Form 8851 is used for this purpose.

*Current Actions:* There are no changes being made to the form at this time.

*Type of Review:* Extension of a currently approved collection.

*Affected Public:* Business or other for-profit organizations.

*Estimated Number of Respondents:* 200,000.

*Estimated Time per Respondent:* 7 hours, 42 minutes.

*Estimated Total Annual Burden Hours:* 1,540,000.

The following paragraph applies to all of the collections of information covered by this notice:

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless the collection of information displays a valid OMB control number. Books or records relating to a collection of information must be retained as long as their contents may become material in the administration of any internal revenue law. Generally, tax returns and tax return information are confidential, as required by 26 U.S.C. 6103.

*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.

Approved: July 6, 2007.

**R. Joseph Durbala,**

*IRS Reports Clearance Officer.*

[FR Doc. E7–14076 Filed 7–19–07; 8:45 am]

**BILLING CODE 4830–01–P**

## DEPARTMENT OF THE TREASURY

### Internal Revenue Service

### Proposed Collection; Comment Request for Revenue Procedure 2006–XX

**AGENCY:** Internal Revenue Service (IRS), Treasury.

**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 IRS is soliciting comments concerning Revenue Procedure 2006–XX, Section 45H Certification.

**DATES:** Written comments should be received on or before September 18, 2007 to be assured of consideration.

**ADDRESSES:** Direct all written comments to R. Joseph Durbala, Internal Revenue Service, Room 6516, 1111 Constitution Avenue, NW., Washington, DC 20224.

**FOR FURTHER INFORMATION CONTACT:** Requests for additional information or copies of the regulations should be directed to Larnice Mack at Internal Revenue Service, Room 6512, 1111 Constitution Avenue, NW., Washington, DC 20224, or at (202) 622–3179, or through the Internet at (*Larnice.Mack@irs.gov*).

**SUPPLEMENTARY INFORMATION:**

*Title:* Section 45H Certification.

*OMB Number:* 1545–2074.

*Revenue Procedure Number:* Revenue Procedure 2006–XX.

*Abstract:* The revenue procedure informs small business refiners how to obtain the certification required under 45H(f) of the Internal Revenue Code.

*Current Actions:* There are no changes being made to this revenue procedure at this time.

*Type of Review:* Extension of a currently approved collection.

*Affected Public:* Business or other for-profit organizations.

*Estimated Number of Respondents:* 50.

*Estimated Average Time per Respondent:* 1 hour; 3 mins.

*Estimated Total Annual Burden Hours:* 75.

The following paragraph applies to all the collections of information covered by this notice:

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless the collection of information displays a valid OMB control number. Books or records relating to a collection of information must be retained as long as their contents may become material in the administration of any internal revenue law. Generally, tax returns and tax return information are confidential, as required by 26 U.S.C. 6103.

*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.

Approved: July 11, 2007.

**Allen Hopkins,**

*IRS Reports Clearance Officer.*

[FR Doc. E7–14095 Filed 7–19–07; 8:45 am]

**BILLING CODE 4830–01–P**

---

## DEPARTMENT OF THE TREASURY

### Internal Revenue Service

**[REG–120616–03; TD 9145]**

### Proposed Collection: Comment Request for Regulation Project

**AGENCY:** Internal Revenue Service (IRS), Treasury.

**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 IRS is soliciting comments concerning an existing final and temporary regulations, REG–120616–03 (TD 9145), Entry of Taxable Fuel, (§§ 48.4081–1T(b) and 48.4081–3T(c)(ii) and (iv)).

**DATES:** Written comments should be received on or before September 18, 2007 to be assured of consideration.

**ADDRESSES:** Direct all written comments to R. Joseph Durbala, Internal Revenue Service, Room 6516, 1111 Constitution Avenue, NW., Washington, DC 20224.

**FOR FURTHER INFORMATION CONTACT:** Requests for additional information or copies of the regulation should be directed to Allan Hopkins, at (202) 622–6665, or at Internal Revenue Service, Room 6516, 1111 Constitution Avenue, NW., Washington, DC 20224, or through the Internet, at *Allan.M.Hopkins@irs.gov.*

**SUPPLEMENTARY INFORMATION:**

*Title:* Entry of Taxable Fuel.

*OMB Number:* 1545–1897.

*Regulation Project Number:* REG–120616–03 (TD 9145).

*Abstract:* The regulation imposes joint and several liability on the importer of record for the tax imposed on the entry of taxable fuel into the U.S. and revises definition of "enterer".

*Current Actions:* There is no change to this existing regulation.

*Type of Review:* Extension of a currently approved collection.

*Affected Public:* Individuals, business or other for-profit organizations, not-for-profit institutions, and Federal, state, local or tribal governments.

*Estimated Number of Respondents:* 1,125.

*Estimated Time per Respondent:* 15 minutes.

*Estimated Total Annual Burden Hours:* 281.

The following paragraph applies to all of the collections of information covered by this notice.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless the collection of information displays a valid OMB control number. Books or records relating to a collection of information must be retained as long as their contents may become material in the administration of any internal revenue law. Generally, tax returns and tax return information are confidential, as required by 26 U.S.C. 6103.

*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.

Approved: July 6, 2007.

**R. Joseph Durbala,**

*IRS Reports Clearance Officer.*

[FR Doc. E7–14096 Filed 7–19–07; 8:45 am]

**BILLING CODE 4830–01–P**

## DEPARTMENT OF THE TREASURY

### Internal Revenue Service

**[EE–43–92]**

### Proposed Collection: Comment Request for Regulation Project

**AGENCY:** Internal Revenue Service (IRS), Treasury.

**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 IRS is soliciting comments concerning an existing final regulation, EE–43–92 (TD 8619), Direct Rollovers and 20-Percent Withholding Upon Eligible Rollover Distributions From Qualified Plans (§§ 1.401(a)(31)–1, 1.402(c)–2, 1.402(f)–1, 1.403(b)–2, and 31.3405(c)–1.

**DATES:** Written comments should be received on or before September 18, 2007 to be assured of consideration.

**ADDRESSES:** Direct all written comments to R. Joseph Durbala, Internal Revenue Service, Room 6411, 1111 Constitution Avenue, NW., Washington, DC 20224.

**FOR FURTHER INFORMATION CONTACT:** Requests for additional information or copies of the regulation should be directed to Allan Hopkins, at (202) 622–6665, or at Internal Revenue Service, Room 6407, 1111 Constitution Avenue, NW., Washington, DC 20224, or through the Internet, at *Allan.M.Hopkins@irs.gov.*

**SUPPLEMENTARY INFORMATION:**

*Title:* Direct Rollovers and 20-Percent Withholding Upon Eligible Rollover Distributions From Qualified Plans.

*OMB Number:* 1545–1341.

*Regulation Project Number:* EE–43–92.

*Abstract:* This regulation implements the provisions of the Unemployment Compensation Amendments of 1992 (Pub. L. 102–318), which impose mandatory 20 percent income tax withholding upon the taxable portion of certain distributions from a qualified pension plan or a tax-sheltered annuity that can be rolled over tax-free to another eligible retirement plan unless such amounts are transferred directly to such other plan in a ''direct rollover'' transaction. These provisions also require qualified pension plans and tax-sheltered annuities to offer their participants the option to elect to make ''direct rollovers'' of their distributions and to provide distributees with a written explanation of the tax laws regarding their distributions and their option to elect such a rollover.

*Current Actions:* There is no change to this existing regulation.

*Type of Review:* Extension of a currently approved collection.

*Affected Public:* Individuals, business or other for-profit organizations, not-for-profit institutions, and Federal, state, local or tribal governments.

*Estimated Number of Respondents:* 10,323,926.

*Estimated Time per Respondent:* 13 minutes.

*Estimated Total Annual Burden Hours:* 2,129,669.

The following paragraph applies to all of the collections of information covered by this notice.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless the collection of information displays a valid OMB control number. Books or records relating to a collection of information must be retained as long as their contents may become material in the administration of any internal revenue law. Generally, tax returns and tax return information are confidential, as required by 26 U.S.C. 6103.

*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.

Approved: July 6, 2007.

**R. Joseph Durbala,**

*IRS Reports Clearance Officer.*

[FR Doc. E7–14098 Filed 7–19–07; 8:45 am]

**BILLING CODE 4830–01–P**

## DEPARTMENT OF THE TREASURY

### Internal Revenue Service

**[PS–52–88]**

### Proposed Collection; Comment Request for Regulation Project

**AGENCY:** Internal Revenue Service (IRS), Treasury.

**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 IRS is soliciting comments concerning an existing final regulation, PS–52–88 (TD 8455), Election to Expense Certain Depreciable Business Assets. (§§ 1.179–2, 1.179–3).

**DATES:** Written comments should be received on or before September 18, 2007 to be assured of consideration.

**ADDRESSES:** Direct all written comments to R. Joseph Durbala, Internal Revenue Service, room 6516, 1111 Constitution Avenue, NW., Washington, DC 20224.

**FOR FURTHER INFORMATION CONTACT:** Requests for additional information or copies of this regulation should be directed to Allan Hopkins, (202) 622–6665, or through the Internet (*Allan.M.Hopkins@irs.gov*) Internal Revenue Service, room 6516, 1111 Constitution Avenue NW., Washington, DC 20224.

**SUPPLEMENTARY INFORMATION:**

*Title:* Election to Expense Certain Depreciable Business Assets.

*OMB Number:* 1545–1201.

*Regulation Project Number:* PS–52–88 Final.

*Abstract:* The regulations provide rules on the election described in Internal Revenue Code section 179(b)(4); the apportionment of the dollar limitation among component members of a controlled group; and the proper order for deducting the carryover of disallowed deduction. The recordkeeping and reporting requirements are necessary to monitor compliance with the section 179 rules.

*Current Actions:* There is no change to this existing regulation.

*Type of Review:* Extension of a currently approved collection.

*Affected Public:* Individuals or households, farms, and business or other for-profit organizations.

*Estimated Number of Respondents:* 20,000.

*Estimated Time per Respondent:* 45 min.

*Estimated Total Annual Burden Hours:* 15,000 hours.

The following paragraph applies to all of the collections of information covered by this notice.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless the collection of information displays a valid OMB control number. Books or records relating to a collection of information must be retained as long as their contents may become material in the administration of any internal revenue law. Generally, tax returns and tax return information are confidential, as required by 26 U.S.C. 6103.

*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.

Approved: June 6, 2007.

**R. Joseph Durbala,**

*IRS Reports Clearance Officer.*

[FR Doc. E7–14101 Filed 7–19–07; 8:45 am]

BILLING CODE 4830–01–P

---

## DEPARTMENT OF THE TREASURY

### Internal Revenue Service

### Open Meeting of the Taxpayer Advocacy Panel Earned Income Tax Credit (EITC) Issue Committee

**AGENCY:** Internal Revenue Service (IRS), Treasury.

**ACTION:** Notice.

**SUMMARY:** An open meeting of the Taxpayer Advocacy Panel Earned Income Tax Credit Issue Committee will be conducted (via teleconference). The Taxpayer Advocacy Panel is soliciting public comments, ideas and suggestions on improving customer service at the Internal Revenue Service.

**DATES:** The meeting will be held Monday, August 13, 2006.

**FOR FURTHER INFORMATION CONTACT:** Audrey Y. Jenkins at 1–888–912–1227 (toll-free), or 718–488–2085 (non toll-free).

**SUPPLEMENTARY INFORMATION:** Notice is hereby given pursuant to Section 10(a)(2) of the Federal Advisory Committee Act, 5 U.S.C. App. (1988) that an open meeting of the Taxpayer Advocacy Panel Earned Income Tax Credit Issue Committee will be held Monday, August 13, 2007 from 10:30 a.m. to 11:30 a.m. ET via a telephone conference call. For information contact Audrey Y. Jenkins at 1–888–912–1227 or (718) 488–2085. The public is invited to make oral comments. Individual comments will be limited to five minutes. Due to limited conference lines, notification of intent to participate in the telephone conference call meeting must be made in advance to Audrey Y. Jenkins at the phone numbers listed above. Written comments may be submitted to Audrey Y. Jenkins, TAP Office, 10 MetroTech Center, 625 Fulton Street, Brooklyn, NY 11201 or posted to the Web site: *http://www.improveirs.org.*

The agenda will include various IRS issues.

Dated: July 16, 2007.

**John Fay,**

*Acting Director, Taxpayer Advocacy Panel.*

[FR Doc. E7–14089 Filed 7–19–07; 8:45 am]

BILLING CODE 4830–01–P

---

## DEPARTMENT OF THE TREASURY

### Internal Revenue Service

### Open Meeting of the Taxpayer Assistance Center Committee of the Taxpayer Advocacy Panel

**AGENCY:** Internal Revenue Service (IRS), Treasury.

**ACTION:** Notice.

**SUMMARY:** An open meeting of the Taxpayer Assistance Center Committee of the Taxpayer Advocacy Panel will be conducted (via teleconference). The Taxpayer Advocacy Panel (TAP) is soliciting public comments, ideas, and suggestions on improving customer service at the Internal Revenue Service.

**DATES:** The meeting will be held Tuesday, August 7, 2007.

**FOR FURTHER INFORMATION CONTACT:** Dave Coffman at 1–888–912–1227, or 206–220–6096.

**SUPPLEMENTARY INFORMATION:** Notice is hereby given pursuant to Section 10(a)(2) of the Federal Advisory Committee Act, 5 U.S.C. App. (1988) that an open meeting of the Taxpayer Assistance Center Committee of the Taxpayer Advocacy Panel will be held Tuesday, August 7, 2007 from 9 a.m. Pacific Time to 10:30 a.m. Pacific Time via a telephone conference call. Due to limited conference lines, notification of intent to participate in the telephone conference call meeting must be made with Dave Coffman. Mr. Coffman can be reached at 1–888–912–1227 or 206–220–6096. If you would like to have the TAP consider a written statement, please call Mr. Coffman at 1–888–912–1227 or 206–220–6096 or write to Dave Coffman, TAP Office, 915 2nd Avenue, MS W–406, Seattle, WA 98174 or you can contact us at *http://www.improveirs.org.*

The agenda will include the following: Various IRS issues.

Dated: July 16, 2007.

**John Fay,**

*Acting Director, Taxpayer Advocacy Panel.*

[FR Doc. E7–14090 Filed 7–19–07; 8:45 am]

BILLING CODE 4830–01–P

---

## DEPARTMENT OF THE TREASURY

### United States Mint

### Notification of Citizens Coinage Advisory Committee August 2007 Public Meeting

*Summary:* Pursuant to United States Code, Title 31, section 5135(b)(8)(C), the United States Mint announces the Citizens Coinage Advisory Committee (CCAC) public meeting and public forum scheduled for August 10, 2007, at the American Numismatic Association's World's Fair of Money ®.

*Date:* August 10, 2007.

*Time:* 10 a.m. to 11:30 p.m. (Public meeting followed by public forum).

*Location:* Midwest Airlines Convention Center, 400 W. Wisconsin Ave., Milwaukee, WI 53203.

*Subject:* Coin Designs, TBD.

Interested persons should call 202–354–7502 for the latest update on meeting time and room location.

*Public Law 108–15 established the CCAC to:*

Advise the Secretary of the Treasury on any theme or design proposals relating to circulating coinage, bullion coinage, Congressional Gold Medals, and national and other medals.

Advise the Secretary of the Treasury with regard to the events, persons, or places to be commemorated by the issuance of commemorative coins in each of the five calendar years succeeding the year in which a commemorative coin designation is made. Make recommendations with respect to the mintage level for any commemorative coin recommended.

*For Further Information Contact:* Cliff Northup, United States Mint Liaison to the CCAC; 801 Ninth Street, NW., Washington, DC 20220; or call 202–354–7200.

Any member of the public interested in submitting matters for the CCAC's consideration is invited to submit them by fax to the following number: 202–756–6830.

**Authority:** 31 U.S.C. 5135(b)(8)(C).

Dated: July 16, 2007.

**Edmund C. Moy,**

*Director, United States Mint.*

[FR Doc. E7–14022 Filed 7–19–07; 8:45 am]

**BILLING CODE 4810–02–P**

# Corrections

Federal Register
Vol. 72, No. 139
Friday, July 20, 2007

This section of the FEDERAL REGISTER contains editorial corrections of previously published Presidential, Rule, Proposed Rule, and Notice documents. These corrections are prepared by the Office of the Federal Register. Agency prepared corrections are issued as signed documents and appear in the appropriate document categories elsewhere in the issue.

## DEPARTMENT OF AGRICULTURE

### Animal and Plant Health Inspection Service

### 7 CFR Part 340

**[Docket No. APHIS–2006–0112]**

**RIN 0579–AC31**

### Introduction of Organisms and Products Altered or Produced Through Genetic Engineering

*Correction*

In proposed rule document 07–3474 beginning on page 39021 in the issue of Tuesday, July 17, 2007, make the following correction:

On page 39021, in the third column, in the second and third lines, ''September 17, 2007'' should read ''September 11, 2007''.

[FR Doc. C7–3474 Filed 7–19–07; 8:45 am]

**BILLING CODE 1505–01–D**

Federal Register

Friday,
July 20, 2007

## Part II

# Department of Energy

## Federal Energy Regulatory Commission

### 18 CFR Part 35

### Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities; Final Rule

**DEPARTMENT OF ENERGY**

**Federal Energy Regulatory Commission**

**18 CFR Part 35**

**[Docket No. RM04–7–000; Order No. 697]**

## Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities

Issued June 21, 2007.

**AGENCY:** Federal Energy Regulatory Commission, Department of Energy.

**ACTION:** Final rule.

**SUMMARY:** The Federal Energy Regulatory Commission (Commission) is amending its regulations to revise Subpart H to Part 35 of Title 18 of the Code of Federal Regulations governing market-based rates for public utilities pursuant to the Federal Power Act (FPA). The Commission is codifying and, in certain respects, revising its current standards for market-based rates for sales of electric energy, capacity, and ancillary services. The Commission is retaining several of the core elements of its current standards for granting market-based rates and revising them in certain respects. The Commission also adopts a number of reforms to streamline the administration of the market-based rate program.

**DATES:** *Effective Date:* This rule will become effective September 18, 2007.

**FOR FURTHER INFORMATION CONTACT:**
Debra A. Dalton (Technical Information), Office of Energy Markets and Reliability, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–6253.
Elizabeth Arnold (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–8818.

**SUPPLEMENTARY INFORMATION:**

TABLE OF CONTENTS

TABLE OF CONTENTS—Continued

TABLE OF CONTENTS—Continued



*Before Commissioners:* Joseph T. Kelliher, Chairman; Suedeen G. Kelly, Marc Spitzer, Philip D. Moeller, and Jon Wellinghoff.

## I. Introduction

1. On May 19, 2006, the Commission issued a Notice of Proposed Rulemaking (NOPR), pursuant to sections 205 and 206 of the Federal Power Act (FPA),[1] in which the Commission proposed to amend its regulations governing market-based rate authorizations for wholesale sales of electric energy, capacity and ancillary services by public utilities. In the NOPR, the Commission proposed to modify all existing market-based authorizations and tariffs so they would reflect any new requirements ultimately adopted in the Final Rule. After considering the comments received in response to the NOPR, the Commission adopts in many respects the proposals contained in the NOPR, but with a number of modifications.

2. This Final Rule represents a major step in the Commission's efforts to clarify and codify its market-based rate policy by providing a rigorous up-front analysis of whether market-based rates should be granted, including protective conditions and ongoing filing requirements in all market-based rate authorizations, and reinforcing its ongoing oversight of market-based rates. The specific components of this rule, in conjunction with other regulatory activities, are designed to ensure that market-based rates charged by public utilities are just and reasonable. There are three major aspects of the Commission's market-based rate regulatory regime.

3. First is the analysis that is the subject of this rule: whether a market-based rate seller or any of its affiliates has market power in generation or transmission and, if so, whether such market power has been mitigated.[2] If the seller is granted market-based rates, the authorization is conditioned on: affiliate restrictions governing transactions and conduct between power sales affiliates where one or more of those affiliates has captive customers; a requirement to file post-transaction electric quarterly reports (EQRs) containing specific information about contracts and transactions; a requirement to file any change of status; and a requirement for all large sellers to file triennial updates.[3]

4. Second, for wholesale sellers that have market-based rate authority and sell into day ahead or real-time organized markets administered by Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs), they do so subject to specific RTO/ISO market rules approved by the Commission and applicable to all market participants. These rules are designed to help ensure that market power cannot be exercised in those organized markets and include additional protections (*e.g.*, mitigation measures) where appropriate to ensure that prices in those markets are just and reasonable. Thus, a seller in such markets not only must have an authorization based on an analysis of that individual seller's market power, but it must also abide by additional rules contained in the RTO/ISO tariffs.

5. Third, the Commission, through its ongoing oversight of market-based rate authorizations and market conditions, may take steps to address seller market power or modify rates. For example, based on its review of triennial market power updates required of market-based rate sellers, its review of EQR filings made by market-based rate sellers, and its review of required notices of change in status, the Commission may institute a section 206 proceeding to revoke a seller's market-based rate authorization if it determines that the seller may have gained market power since its original market-based rate authorization. The Commission may also, based on its review of EQR filings or daily market price information, investigate a specific utility or anomalous market circumstances to determine whether there has been any conduct in violation of RTO/ISO market rules or Commission orders or tariffs, or any prohibited market manipulation, and take steps to remedy any violations. These steps could include, among other things, disgorgement of profits and refunds to customers if a seller is found to have violated Commission orders, tariffs or rules, or a civil penalty paid to the United States Treasury if a seller is found to have engaged in prohibited market manipulation or to have violated Commission orders, tariffs or rules.

6. The Commission recognizes that several recent court decisions by the United States Court of Appeals for the Ninth Circuit[4] have created some uncertainty for sellers transacting pursuant to our market-based rate program. The cases raise issues with respect to the circumstances under which sellers' pre-authorized market-based rate sales may be subject to retroactive refunds and the circumstances under which buyers might be able to invalidate or modify contracts based on the argument that the contracts were entered into at a time when markets were dysfunctional. The Commission's first and foremost duty is to protect customers from unjust and unreasonable rates; however, we recognize that uncertainties regarding rate stability and contract sanctity can have a chilling effect on investments and a seller's willingness to enter into long-term contracts and this, in turn, can harm customers in the long run. The Commission recently provided guidance in this regard, noting that these Ninth Circuit decisions addressed a unique set of facts and a market-based rate program that has undergone substantial improvement since 2001, and reiterating that an *ex ante* finding of the absence of market power, coupled with the EQR filing and effective regulatory oversight qualifies as sufficient prior review for market-based rate contracts to satisfy the notice and filing requirements of FPA section 205.[5] Through this Final Rule, the Commission is clarifying and further

[1] 16 U.S.C. 824d, 824e.

[2] The Commission also considers whether the seller or its affiliates can erect other barriers to entry (*e.g.*, key sites for building new power supply; key inputs to power supply) in the relevant market and whether there is evidence of affiliate abuse or reciprocal dealing.

[3] During the past three years, the Commission has initiated over 20 investigations under section 206 of the FPA because of concerns of possible market power. Several of those investigations led to the revocation or voluntary relinquishing of market-based rate authority and the ordering of refunds by sellers.

[4] *See State of California, ex rel. Bill Lockyer* v. *FERC*, 383 F.3d 1006 (9th Cir. 2004), *cert. denied* (S. Ct. Nos. 06–888 and 06–1100, June 18, 2007) (*Lockyer*); *Public Utility District No. 1 of Snohomish County, Washington* v. *FERC*, 471 F.3d 1053 (9th Cir. 2006) (*Snohomish*); *Public Utilities Commission of the State of California and California Electric Oversight Board* v. *FERC*, 474 F.3d 587 (9th Cir. 2007) (*California Commission*).

[5] *CAlifornians for Renewable Energy, Inc.* v. *Cal. Pub. Util. Com'n*, 119 FERC ¶ 61,058 (2007).

improving its market-based rate program. Moreover, the Commission will explore ways to continue to improve its market-based rate program and processes to assure appropriate customer protections but at the same time provide greater regulatory and market certainty for sellers in light of the above court opinions.

## II. Background

7. In 1988, the Commission began considering proposals for market-based pricing of wholesale power sales. The Commission acted on market-based rate proposals filed by various wholesale suppliers on a case-by-case basis. Over the years, the Commission developed a four-prong analysis used to assess whether a seller should be granted market-based rate authority: (1) Whether the seller and its affiliates lack, or have adequately mitigated, market power in generation; (2) whether the seller and its affiliates lack, or have adequately mitigated, market power in transmission; (3) whether the seller or its affiliates can erect other barriers to entry; and (4) whether there is evidence involving the seller or its affiliates that relates to affiliate abuse or reciprocal dealing.

8. The Commission initiated the instant rulemaking proceeding in April 2004 to consider ''the adequacy of the current analysis and whether and how it should be modified to assure that prices for electric power being sold under market-based rates are just and reasonable under the Federal Power Act.'' [6] At that time, the Commission noted that much has changed in the industry since the four-prong analysis was first developed and posed a number of questions that would be explored through a series of technical conferences.

9. On April 14, 2004, the Commission issued an order modifying the then-existing generation market power analysis and its policy governing market power mitigation, on an interim basis.[7] The April 14 Order adopted a policy that provided sellers a number of procedural options, including two indicative generation market power screens (an uncommitted pivotal supplier analysis and an uncommitted market share analysis), and the option of proposing mitigation tailored to the particular circumstances of the seller that would eliminate the ability to exercise market power. The order also explained that sellers could choose to adopt cost-based rates. On July 8, 2004, the Commission addressed requests for rehearing of the April 14 Order, reaffirming the basic analysis, but clarifying and modifying certain instructions for performing the generation market power analysis. Over the next year, the Commission convened four technical conferences, seeking input regarding all four prongs of the analysis.

10. On May 19, 2006, the Commission issued a NOPR in this proceeding.[8] The Commission explained that refining and codifying effective standards for market-based rates would help customers by ensuring that they are protected from the exercise of market power and would also provide greater certainty to sellers seeking market-based rate authority.

11. The regulations proposed in the NOPR adopted in most respects the Commission's existing standards for granting market-based rates, and proposed to streamline certain aspects of its filing requirements to reduce the administrative burdens on sellers, customers and the Commission. The Commission received over 100 comments and reply comments in response to the NOPR. A list of commenters is attached as Appendix E.

## III. Overview of Final Rule

12. In this Final Rule, the Commission revises and codifies in the Commission's regulations the standards for market-based rates for wholesale sales of electric energy, capacity and ancillary services. The Commission also adopts a number of reforms to streamline the administration of the market-based rate program. As set forth below, the Final Rule adopts in many respects the proposals contained in the NOPR, but with a number of modifications.

### *Horizontal Market Power*

13. In this Final Rule, the Commission adopts, with certain modifications, two indicative market power screens (the uncommitted market share screen (with a 20 percent threshold) and the uncommitted pivotal supplier screen), each of which will serve as a cross check on the other to determine whether sellers may have market power and should be further examined. Sellers that fail either screen will be rebuttably presumed to have market power. However, such sellers will have full opportunity to present evidence (through the submission of a Delivered Price Test (DPT) analysis) demonstrating that, despite a screen failure, they do not have market power, and the Commission will continue to weigh both available economic capacity and economic capacity when analyzing market shares and Hirschman-Herfindahl Indices (HHIs).

14. With regard to control over generation capacity, the Commission finds that the determination of control is appropriately based on a review of the totality of circumstances on a fact-specific basis. No single factor or factors necessarily results in control. The Commission will require a seller to make an affirmative statement as to whether a contractual arrangement (energy management agreement, tolling agreement, specific contractual terms, etc.) transfers control and to identify the party or parties it believes controls the generation facility. Regarding a presumption of control, the Commission will continue its practice of attributing control to the owner absent a contractual agreement transferring such control, and we provide guidance as to how we will consider jointly-owned facilities.

15. The Commission adopts its current approach with regard to the default relevant geographic market, with some modifications. In particular, the Commission will continue to use a seller's control area (balancing authority area) [9] or the RTO/ISO market, as applicable, as the default relevant geographic market. However, where the Commission has made a specific finding that there is a submarket within an RTO, that submarket becomes the default relevant geographic market for sellers located within the submarket for purposes of the market-based rate analysis. The Commission also provides guidance as to the factors the Commission will consider in evaluating whether, in a particular case, to adopt an alternative geographic market instead of relying on the default geographic market.

16. The Commission modifies the native load proxy for the market share screens from the minimum peak day in the season to the average peak native load, averaged across all days in the season, and clarifies that native load can only include load attributable to native load customers based on the definition of native load commitment in § 33.3(d)(4)(i) of the Commission's regulations. In addition, sellers are

[6] *Market-Based Rates for Public Utilities*, 107 FERC ¶ 61,019 AT P 1(2004) (initiating rulemaking proceeding).

[7] *AEP Power Marketing, Inc.*, 107 FERC ¶ 61,018 (April 14 Order), *order on reh'g*, 108 FERC ¶ 61,026 (2004) (July 8 Order).

[8] *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Notice of Proposed Rulemaking, 71 FR 33102 (Jun. 7, 2006), FERC Stats. & Regs. ¶ 32,602 (2006) (NOPR).

[9] As discussed below in the Horizontal Market Power section, the Commission adopts the use of balancing authority area instead of control area.

given the option of using seasonal capacity instead of nameplate capacity.

17. The Commission retains the snapshot in time approach based on historical data for both the indicative screens and the DPT analysis and disallows projections to that data. A standard reporting format is adopted for sellers to follow when summarizing their analysis.

18. The Commission modifies the treatment of newly constructed generation and adopts an approach that requires all sellers to perform a horizontal analysis for the grant of market-based rate authority.

19. With regard to simultaneous transmission import limit studies (SILs), the Commission adopts the requirement that the SIL study be used as a basis for transmission access for both the indicative screens and the DPT analysis. Further, the Commission clarifies that the SIL study as shown in Appendix E of the April 14 Order is the only study that meets our requirements. The Commission provides guidance regarding how to perform the SIL study, including accounting for specific OASIS practices.

20. Finally, the Commission adopts procedures under which intervenors in section 205 proceedings may obtain expedited access to Critical Energy Infrastructure Information (CEII) or other information for which privileged treatment is sought.

*Vertical Market Power*

21. With regard to vertical market power and, in particular, transmission market power, the Commission continues the current policy under which an open access transmission tariff (OATT) is deemed to mitigate a seller's transmission market power. However, in recognition of the fact that OATT violations may nonetheless occur, the Commission states that a finding of a nexus between the specific facts relating to the OATT violation and the entity's market-based rate authority may subject the seller to revocation of its market-based rate authority or other remedies the Commission may deem appropriate, such as disgorgement of profits or civil penalties. In addition, the Commission creates a rebuttable presumption that all affiliates of a transmission provider should lose their market-based rate authority in each market in which their affiliated transmission provider loses its market-based rate authority as a result of an OATT violation.

22. With regard to other barriers to entry, the Commission adopts the NOPR proposal to consider a seller's ability to erect other barriers to entry as part of the vertical market power analysis, but modifies the requirements when addressing other barriers to entry. The Commission also provides clarification regarding the information that a seller must provide with respect to other barriers to entry (including which inputs to electric power production the Commission will consider as other barriers to entry). The Commission adopts a rebuttable presumption that ownership or control of, or affiliation with an entity that owns or controls, intrastate natural gas transportation, intrastate natural gas storage or distribution facilities; sites for generation capacity development; and sources of coal supplies and the transportation of coal supplies such as barges and rail cars do not allow a seller to raise entry barriers, but intervenors are allowed to demonstrate otherwise. The Final Rule also requires a seller to provide a description of its ownership or control of, or affiliation with an entity that owns or controls, intrastate natural gas transportation, intrastate natural gas storage or distribution facilities; sites for generation capacity development; and sources of coal supplies and the transportation of coal supplies such as barges and rail cars. The Commission will require sellers to provide this description and to make an affirmative statement that they have not erected barriers to entry into the relevant market and will not erect barriers to entry into the relevant market. The Final Rule clarifies that the obligation in this regard applies both to the seller and its affiliates, but is limited to the geographic market(s) in which the seller is located.

*Affiliate Abuse*

23. With regard to affiliate abuse, the Commission adopts the NOPR proposal to discontinue considering affiliate abuse as a separate ''prong'' of the market-based rate analysis and instead to codify affiliate restrictions in the Commission's regulations and address affiliate abuse by requiring that the provisions provided in the affiliate restrictions be satisfied on an ongoing basis as a condition of obtaining and retaining market-based rate authority. As codified in this Final Rule, the affiliate restrictions include a provision prohibiting power sales between a franchised public utility with captive customers and any market-regulated power sales affiliates[10] without first receiving Commission authorization for the transaction under section 205 of the FPA. The Commission also codifies as part of the affiliate restrictions the requirements that previously have been known as the market-based rate ''code of conduct'' (governing the separation of functions, the sharing of market information, sales of non-power goods or services, and power brokering), as clarified and modified in this Final Rule. The Commission modifies certain of these provisions, including separation of functions and information sharing, consistent with certain requirements and exceptions contained in the Commission's standards of conduct.[11] In the Final Rule the Commission defines ''captive customers'' as ''any wholesale or retail electric energy customers served under cost-based regulation'' and provides clarification that the definition of ''captive customers'' does not include those customers who have retail choice, *i.e.*, the ability to select a retail supplier based on the rates, terms and conditions of service offered. In addition, among other clarifications, the Commission clarifies and modifies the definition of ''non-regulated power sales affiliate,'' and changes the term to ''market-regulated power sales affiliate.''

24. The Commission also provides clarification as to what types of affiliate transactions are permissible and the criteria used to make those decisions, and how the Commission will treat merging partners. In addition, the Commission codifies in the regulations a prohibition on the use of third-party entities, including energy/asset managers, to circumvent the affiliate restrictions, but does not adopt the NOPR proposal to treat energy/asset managers as affiliates. The Commission also provides clarification regarding the Commission's market-based rate policies as they relate to cooperatives.

*Mitigation*

25. With regard to mitigation, in the Final Rule the Commission retains the incremental cost plus 10 percent methodology as the default mitigation for sales of one week or less; the default mitigation rate for mid-term sales (sales of more than one week but less than one year) priced at an embedded cost ''up to'' rate reflecting the costs of the unit(s) expected to provide the service; and the existing policy for sales of one year or more (long-term) sales.[12] The

[10] In the NOPR, the Commission proposed to define the term ''non-regulated power sales affiliate.'' As discussed below, this Final Rule uses the term ''market-regulated power sales affiliate'' instead.

[11] 18 CFR part 358.

[12] We note here that we expect mitigated sellers adopting the default cost-based rates or proposing new cost-based rates will propose a cost-based rate tariff of general applicability for sales of less than one year, and sales of power for one year or longer will be filed with the Commission on a stand-alone basis.

Commission will continue to allow sellers to propose alternative cost-based methods of mitigation tailored to their particular circumstances. The Final Rule also states that the Commission will make its stacking methodology available for the public.[13] In addition, the Commission will continue the practice of allowing discounting and will permit selective discounting by mitigated sellers provided that the sellers do not use such discounting to unduly discriminate or give undue preference.

26. The Commission concludes that use of the Western Systems Power Pool (WSPP) Agreement may be unjust, unreasonable or unduly discriminatory or preferential for certain sellers. Therefore, in an order being issued concurrently with this Final Rule, the Commission is instituting a proceeding under section 206 of the FPA to investigate whether, for sellers found to have market power or presumed to have market power in a particular market, the WSPP Agreement rate for coordination energy sales is just and reasonable in such market.

27. The Commission does not impose an across-the-board ''must offer'' requirement for mitigated sellers. While wholesale customer commenters have raised concerns relating to their ability to access needed power, the Commission concludes that there is insufficient record evidence to support instituting a generic ''must offer'' requirement.

28. The Commission limits mitigation to the market in which the seller has been found to possess, or chosen not to rebut the presumption of, market power and does not place limitations on a mitigated seller's ability to sell at market-based rates in areas in which the seller has not been found to have market power.

29. Finally, regarding mitigation, the Final Rule allows mitigated sellers to make market-based rate sales at the metered boundary between a mitigated balancing authority area and a balancing authority area in which the seller has market-based rate authority under the conditions set forth herein, including a record retention requirement, and provides a tariff provision to allow for such sales.

*Implementation Process*

30. The Commission adopts the NOPR proposal to create a category of sellers (Category 1 sellers) that are exempt from the requirement to automatically submit updated market power analyses, with certain clarifications and modifications. In addition, the Commission adopts the NOPR proposal to implement a regional approach to updated market power analyses, but reduces the number of regions from nine to six.

31. As for a standardized tariff, the Commission does not adopt the NOPR proposal to adopt a market-based rate tariff of general applicability that all market-based rate sellers will be required to file as a condition of market-based rate authority and to require each corporate family to have only one tariff, with all affiliates with market-based rate authority separately identified in the tariff. Instead, the Commission adopts specific market-based rate tariff provisions that the Commission will require to be part of a seller's market-based rate tariff. However, the Commission will allow a seller to include seller specific terms and conditions in its market-based rate tariff, but the Commission will not review any of these provisions, as they are presumed to be just and reasonable based on the Commission's finding that the seller and its affiliates lack or have adequately mitigated market power in the relevant market.

*Miscellaneous Issues*

32. The Commission also provides clarifications in the Final Rule with regard to accounting waivers, Part 34 blanket authorizations, sellers affiliated with foreign entities, and the change in status reporting requirement. Further, the Commission abandons the posting requirements for third party sellers of ancillary services at market-based rates as redundant of other reporting requirements.

## IV. Discussion

### *A. Horizontal Market Power*

#### 1. Whether To Retain the Indicative Screens

33. As discussed in detail below, the Commission is adopting in this Final Rule two indicative horizontal market power screens, each of which will serve as a cross-check on the other to determine whether sellers may have market power and should be further examined. Although some sellers disagree with the use of two screens or find flaws in them, we conclude that this conservative approach will allow the Commission to more readily identify potential market power. Sellers that fail either screen will be rebuttably presumed to have market power. However, such sellers will have full opportunity to present evidence (through the submission of a DPT analysis) demonstrating that, despite a screen failure, they do not have market power. No screen is perfect, but we believe this approach appropriately balances the need to protect against market power with the desire not to place unnecessary filing burdens on utilities.

34. The first screen is the wholesale market share screen, which measures for each of the four seasons whether a seller has a dominant position in the market based on the number of megawatts of uncommitted capacity owned or controlled by the seller as compared to the uncommitted capacity of the entire relevant market.[14]

35. The second screen is the pivotal supplier screen, which evaluates the potential of a seller to exercise market power based on uncommitted capacity at the time of the balancing authority area's annual peak demand. This screen focuses on the seller's ability to exercise market power unilaterally. It examines whether the market demand can be met absent the seller during peak times. A seller is pivotal if demand cannot be met without some contribution of supply by the seller or its affiliates.[15]

36. Use of the two screens together enables the Commission to measure market power at both peak and off-peak times, and to examine the seller's ability to exercise market power unilaterally and in coordinated interaction with other sellers. Use of the two screens, therefore, provides a more complete picture of a seller's ability to exercise market power.[16]

37. As discussed more fully in the following sections, with regard to determining the total supply in the relevant market, the horizontal market power analysis centers on and examines the balancing authority area where the seller's generation is physically located. Total supply is determined by adding the total amount of uncommitted capacity located in the relevant market (including capacity owned by the seller and competing suppliers) with that of uncommitted supplies that can be imported (limited by simultaneous transmission import capability) into the relevant market from the first-tier markets.

38. Uncommitted capacity is determined by adding the total nameplate or seasonal capacity [17] of

[13] This is addressed in the Mitigation section discussion concerning the cost-based rate methodology for sales of more than one week but less than one year.

[14] April 14 Order, 107 FERC ¶ 61,018 at P 100.

[15] *Id.* at P 72.

[16] *Id.*

[17] As discussed more fully below, in this Final Rule, the Commission gives sellers the option of using seasonal capacity instead of nameplate capacity.

generation owned or controlled through contract and firm purchases, less operating reserves, native load commitments and long-term firm sales.[18] Uncommitted capacity from a seller's remote generation (generation located in an adjoining balancing authority area) should be included in the seller's total uncommitted capacity amounts. Any simultaneous transmission import capability should first be allocated to the seller's uncommitted remote generation. Any remaining simultaneous transmission import capability would then be allocated to any uncommitted competing supplies.

39. Capacity reductions as a result of operating reserve requirements should be no higher than State and Regional Reliability Council operating requirements for reliability (*i.e.*, operating reserves). Any proposed amounts that are higher than such requirements must be fully supported and will be considered on a case-by-case basis. Moreover, if an intervenor provides conclusive evidence that a seller did not in actual practice comply with the NERC or regional reliability council operating reserve requirements, then we will take this into account in determining the amount of the operating reserve deduction. However, we emphasize that we expect each utility to meet its NERC and regional reliability council reserve requirements, and that absent a clear showing to the contrary by an intervenor, the required operating reserve requirement is what we will use as the deduction in the market-based rate calculation.[19]

40. The Commission does not expect that sellers will have planned generation outages scheduled for the annual peak load day. However, on a case-by-case basis, the Commission will consider credible evidence that planned generation outages for the peak load day of the year should be included based on the particular circumstances of the seller.[20]

41. With regard to the pivotal supplier analysis, after computing the total uncommitted supply available to serve the relevant market, the next step in this analysis involves identifying the wholesale market. The proxy for the wholesale load is the annual peak load (needle peak) less the proxy for native load obligation (*i.e.*, the average of the daily native load peaks during the month in which the annual peak load day occurs). Peak load is the largest electric power requirement (based on net energy for load) during a specific period of time, usually integrated over one clock hour and expressed in megawatts, for the native load and firm wholesale requirements sales.

42. To calculate the net uncommitted supply available to compete at wholesale, the pivotal supplier analysis deducts the wholesale load from the total uncommitted supply. If the seller's uncommitted capacity is less than the net uncommitted supply, the seller satisfies the pivotal supplier portion of the generation market power analysis and passes the screen. If the seller's uncommitted capacity is equal to or greater than the net uncommitted supply, then the seller fails the pivotal supplier analysis which creates a rebuttable presumption of market power.

43. With regard to the wholesale market share analysis, which measures for each of the four seasons whether a seller has a dominant position in the market based on the number of megawatts of uncommitted capacity owned or controlled by the seller as compared to the uncommitted capacity of the entire relevant market, uncommitted capacity amounts are used, as described above, with the following variation. Planned outages (that were done in accordance with good utility practice) for each season will be considered. Planned outage amounts should be consistent with those as reported in FERC Form No. 714. To determine the amount of planned outages for a given season, the total number of MW-days of outages is divided by the total number of days in the season. For example, if 500 MW of generation that is out for six days during the winter period the calculation of planned outages would be: (500 MW × 6)/91 or 33 MW.

44. The market share analysis adopts an initial threshold of 20 percent. That is, a seller who has less than a 20 percent market share in the relevant market for all seasons will be considered to satisfy the market share analysis.[21] A seller with a market share of 20 percent or more in the relevant market for any season will have a rebuttable presumption of market power but can present historical evidence to show that the seller satisfies our generation market power concerns.

Commission Proposal

45. In the NOPR, the Commission proposed to retain the indicative screens (pivotal supplier and market share) to assess horizontal market power that were initially adopted in April 2004.[22] Because the indicative screens are intended only to identify the sellers that require further review, the Commission proposed to retain the 20 percent threshold for the wholesale market share indicative screen, stating that the 20 percent market share threshold strikes the right balance in seeking to avoid both "false negatives" and "false positives." The Commission also proposed to continue to measure pivotal suppliers at the time of the annual peak load in the pivotal supplier indicative screen, which is the most likely point in time that a seller will be a pivotal supplier. For this reason, the Commission did not propose to expand the pivotal supplier analysis to other time periods.

Comments

46. Numerous commenters question whether the Commission should retain the current indicative screens in whole or in part. For example, Southern, Duke and EEI advocate abandoning the market share indicative screen altogether. They argue that the market share indicative screen is "fatally flawed" because it does not take into account wholesale demand in the relevant market[23] which makes it difficult for traditional utilities outside of RTOs/ISOs to pass.[24] E.ON. US. and PNM/Tucson separately argue that one must consider the level of demand that is seeking supply and, more particularly, what ability sellers have to exercise market power over those buyers.[25] In this regard, E.ON. US. and

[18] Sellers may deduct generation associated with their long-term firm requirements sales, unless the Commission disallows such deductions based on extraordinary circumstances.

[19] April 14 Order, 107 FERC ¶ 61,018 at P96.

[20] As noted below, the market share screen deducts generation capacity used for planned outages (that were done in accordance with good utility practice) in all four seasons in order to reflect the typical operation of generation units.

[21] The 20 percent threshold is consistent with § 4.134 of the U.S. Department of Justice 1984 Merger Guidelines issued June 14, 1984, reprinted in Trade Reg. Rep. P13,103 (CCH 1988): "The Department [of Justice] is likely to challenge any merger satisfying the other conditions in which the acquired firm has a market share of 20 percent or more."

[22] *See April 14 Order, 107 FERC ¶ 61,018.*

[23] Southern at 11, Duke at 20, EEI at 6–7.

[24] Duke at 17, EEI at 8–9.

[25] E.ON. US. at 16–17 and PNM/Tucson at 5–6. According to E.ON. US. and PNM/Tucson, the past decade has seen strong development in the West of open access to transmission and the ownership of generating assets, solely or jointly, by formerly "captive" wholesale customers. As a result, any analysis that has as its foundation division of the market into suppliers and presumptively captive customers is at odds with present reality, in which wholesale customers have a host of suppliers seeking their business. E.ON. US. and PNM/Tucson state that an illustration of how open access in the West has enhanced the ability of load serving entities to secure competitive resources on an efficient scale across control areas is provided by a recent Southwest Public Power Resources Group

PNM/Tucson argue that to the extent the market share screen does not consider wholesale demand, it is not a useful indicator, and in fact is almost universally a false indicator of the ability of a seller to exercise market power over demand. Also, EEI argues that because of design flaws inherent in the market share screen as well as the negative impact that the use of this test has had since 2004 on the development of competitive wholesale markets (through the inappropriate exclusion of the majority of non-RTO utilities from participating in that market), the market share screen should be eliminated for all market power screening and analysis purposes.[26]

47. EEI contends that the Commission should use only the pivotal supplier screen for indicative screening purposes and the DPT pivotal supplier and market concentration analyses for the purposes of rebutting the presumption of generation market power that would result from the failure of the indicative pivotal supplier screen. EEI argues that if the Commission continues to use the market share screen as an initial screen, the Commission should not include a market share test as a component of any subsequent DPT analysis of market power.

48. E.ON U.S. and PNM/Tucson generally agree, stating that market share is an unreliable measure of market power in competitive energy markets and that the courts have long recognized that market share is not a reliable indicator of market power in regulated markets.[27] In particular, E.ON U.S. and PNM/Tucson argue that even a marginal failure of the market share screen results in a rebuttable presumption of market power that has tremendous consequences by forcing sellers to proceed to costly and time-consuming DPT analysis or agree to mitigation. As a result, the ''false positives'' arising from the market share screen dampen the vigor of competitive wholesale market participation by unnecessarily curtailing the market-based authority of entities that, in fact, lack market power (to the extent such entities choose not to pursue a costly and uncertain effort to rebut the presumption of market power created by the screen failure).[28]

49. Duke and Southern suggest that a wholesale contestable load analysis (also described as a ''competitive alternatives'' analysis)[29] should be added to the indicative screens, which would consider the amount of excess market supply available to serve the amount of wholesale demand seeking supply.[30] Generally, if available non-applicant supply is at least twice the contestable load, advocates of the contestable load analysis believe that is sufficient to make a finding that the market is competitive.[31] Other commenters agree that the market share indicative screen can diminish competition because sellers that are subjects of an FPA section 206 investigation tend to choose mitigation rather than challenge the presumption of market power.[32]

50. Duke argues that the Commission has yet to establish a need for using the market share indicative screen in addition to the pivotal supplier indicative screen in assessing the potential for the exercise of generation market power. In this regard, Duke argues that the Commission itself acknowledged in the April 14 Order (establishing the new indicative market power screens) that if a supplier passes the pivotal supplier indicative screen, it would not be able to exercise generation market power. Thus, Duke concludes that the use of any other indicative screens would appear to be redundant and an unwarranted burden on market-based rate sellers.[33] Further, Duke submits that neither of the rationales originally cited by the Commission in support of the market share screen—its ability to identify ''coordinating behavior,'' or its ability to detect the exercise of market power in off-peak periods—has been validated. In this regard, Duke submits that the potential for ''coordinating behavior'' should consider overall market concentration levels as measured by HHIs and in any event, such behavior is already subject to oversight and substantial penalties under the antitrust laws and the Commission's recently adopted rule prohibiting market manipulation. Further, Duke claims that the nearly universal failure rate of load-serving utilities under the market share indicative screen in their control areas underscores its limited value as an indicator of off-peak market power.[34]

51. Duke states that a review of filings by vertically integrated utilities that are not RTO participants shows that the vast majority have failed the market share screen in their control areas, and most have subsequently been forced to adopt some form of cost-based mitigation for wholesale sales in that market. Yet Duke is unaware of any credible evidence suggesting that any form of generation market power has been exercised by these utilities. Instead, Duke states that the Commission has revoked market-based rate authority and imposed mitigation on the basis of indicative screen results that suggest the potential for market power.[35] APPA/TAPS counter that the Commission should not limit its response to market power only to instances of its actual exercise; they note that the Commission considers whether a seller and its affiliates have market power or have mitigated it, not whether it has been exercised.[36]

52. Another commenter suggests substituting the HHI for the market share indicative screen or supplementing the indicative screens with the HHI, reasoning that the market must be evaluated, not just the individual market share.[37]

53. Southern states that the Commission should rely upon any indicative screens only in conjunction with an optional ''expedited track'' safe harbor review. Under Southern's proposal, the indicative screens would be voluntary and those submitting to and passing the screens would be permitted to retain or obtain market-based rate authority, subject to a proceeding under section 206 of the FPA, under which the party seeking to challenge the rate must submit substantial evidence justifying revocation. If a seller fails the screen(s), or if it elects to submit a DPT rather than voluntarily submit the indicative screens, then a robust market power assessment should be used to determine whether (or the extent to which) the

request for proposals for 255 MW in 2007, growing to 962 MW by 2014 in four control areas—Arizona Public Service, Salt River Project, Western Area Power Administration-Desert Southwest Region and Tucson Electric. (The Southwest Public Power Resources Group represents thirty-nine public power entities in Arizona, California, and Nevada.) See Southwestern Public Utilities Issue Long-Term RFP, ELECTRIC POWER DAILY, July 14, 2006, at 3.

[26] EEI at 10.

[27] *Citing Cost Mgmt. Servs., Inc.* v. *Wash. Natural Gas Co.,* 99 F.3d 937, 950–51 (9th Cir. 1996) *(Cost Management); Rebel Oil Co., Inc.* v. *Atl. Richfield Co.,* 51 F.3d 1421, 1439 (9th Cir. 1995) (Rebel); *S. Pac. Communications Co.* v. *AT&T Co.,* 740 F.2d 980, 1000 (D.C. Cir. 1984) *(Southern Pacific Communications); MCI Communications Corp.* v. *AT&T Co.,* 708 F.2d 1081, 1107 (7th Cir. 1983) *(MCI Communications); Mid-Tex. Communications Sys., Inc.* v. *AT&T Co.,* 615 F.2d 1372, 1386–89 (5th Cir. 1980) *(Mid-Tex Communications); Almeda Mall, Inc.* v. *Houston Lighting & Power Co.,* 615 F.2d 343, 354 (5th Cir. 1980) *(Almeda).*

[28] E.ON U.S. at 16; PNM/Tucson at 5–6.

[29] Dr. Pace at 12.

[30] Duke at 21, Southern at 16–17.

[31] Dr. Pace at 16.

[32] E.ON U.S. at 15–16; PNM/Tucson at 5–6, EEI at 10.

[33] Duke reply comments at 15 and n. 21.

[34] Duke reply comments at 15 and n. 22.

[35] Duke at 16.

[36] APPA/TAPS reply comments at 6–7, citing Duke at 16.

[37] Drs. Broehm & Fox-Penner at 2–4.

seller should be permitted to sell power at market-based rates.

54. In Southern's view, failure of the indicative screens should not give rise to a presumption of market power.[38] Southern argues that mere failure to pass a screen, without more robust market power assessments, is an insufficient basis upon which to base a presumption of market power. Southern argues this is because, in the case of the pivotal supplier screen, the Commission itself admits that it does not give a full picture and that the DPT provides better information. With regard to the market share screen, Southern argues that the market share screen has even more basic problems as an indicator of market power. Southern states that, because of the market share analysis' serious flaws, the great majority of integrated franchised public utilities inevitably will fail the market share screen. Thus, with respect to integrated franchised public utilities, the market share screen serves no real purpose other than to state the obvious: Integrated franchised public utilities build and maintain adequate resources to serve their native loads and inevitably will have market shares greater than 20 percent in their home control areas under the Commission's computational procedures. Southern states that, since the DPT reduces the level of false positives and is a more definitive means for determining the existence of market power, the Commission should use the DPT as the default test.[39] PPL agrees with Southern's proposal that the indicative screens be made voluntary.[40]

55. Southern states that if the market share screen is retained, it should be adjusted for forced outages because such capacity is not available. Southern also notes that forced outages are tracked and reported to the North American Electric Reliability Corporation (NERC), which presents generating unit availability statistics data for generator unit groups.[41]

56. NRECA disagrees with Southern's proposal, stating that forced outage deductions have little effect when applied to all sellers.[42] It also believes that sellers do not make forced outage deductions in long-term contracts; therefore, it is inappropriate to make the deduction for the market power tests.

57. While EPSA does not agree with some of the Commission's proposed changes to the horizontal analysis in the NOPR (*i.e.*, changes to the post-1996 exemption and the native load proxy), in general, EPSA supports the two indicative screens as a means for indicating that an entity might have market power.

58. EPSA notes that it is time to move beyond the battle over crafting the perfect screens, arguing: (1) It is likely no such perfect screens exist, as evidenced by the fact that stakeholders and the Commission have gone through several iterations to get to today's screens; and (2) in the end, the screens are only indicative measures. EPSA notes that failure of one or both of the screens does not brandish an entity with market power, but merely raises a flag that further analysis is necessary in order to assess an entity's ability to exercise market power. The current state of wholesale electricity markets, EPSA argues, requires indicative screens that are neither definitive nor an aperture letting everything pass, but rather a sieve that catches potential problems for further examination. EPSA agrees with retention of both of the current indicative screens and the "next steps" set forth for those entities that fail one or both of those screens.

59. Several other commenters also support retention of the indicative screens. Some of these commenters state that, because section 205 of the FPA requires rates to be just and reasonable, a market share indicative screen is appropriate to ensure that outcome. NRECA adds that "[b]ecause of past or present State regulation, many traditional public utilities have acquired dominant market shares of generation capacity in their own control areas—sufficient to enable them to exercise market power absent regulation of their behavior. NRECA submits that regardless of the cause the incumbent public utilities will remain the dominant firms in their own control areas absent significant new market entry in the form of new generation construction in the control area by independent firms, or significant transmission construction to permit entry by generation outside the control area. Morgan Stanley also favors retaining the market share indicative screen, noting that failure of the market share indicative screen does not mean the process is unfair, and asserting that exclusive reliance on the pivotal supplier indicative screen may compromise market power detection.[43]

60. With regard to the suggestion that the Commission adopt a contestable load analysis, several commenters criticize the contestable load analysis, stating that it changes the focus of the market power analysis from the seller to the market. They counter that the contestable load analysis is unsound, with APPA/TAPS citing Federal Trade Commission (FTC) comments in this proceeding that such an analysis is flawed.[44] NRECA states that commenters have not provided sufficient justification for using a contestable load analysis.

61. With regard to Southern's suggestion that the indicative screens be made voluntary and function as a safe harbor, such that screen failure would simply mean that further review of the seller would be appropriate, but not merit a section 206 investigation, NRECA states that Southern's argument is contrary to law. NRECA argues that, as the proponent of a tariff allowing it to charge market-based rates, the public utility has the burden of proof to demonstrate that its wholesale rates will be disciplined by competition. NRECA submits that failing the indicative screens indicates that the seller has not yet provided " 'empirical proof' " that competition will drive down prices to just and reasonable levels as the FPA requires.[45]

Commission Determination

62. We adopt the proposal in the NOPR to retain both of the indicative screens. The intent of the indicative screens is to identify the sellers that raise no horizontal market power concerns and can otherwise be considered for market-based rate authority. At the same time, sellers that do not pass the indicative screens are allowed to provide additional analysis

[38] Southern argues that, in the context of the indicative screens, the prejudice associated with integrated franchised public utility status is severe and instead of providing a fair or meaningful measure of market power, the market share screen operates to create *a priori* evidentiary presumption of guilt, the screen is improper, creates due process concerns, and should not be adopted for purposes of the final rule.

[39] Southern at 8, 11–13.

[40] PPL reply comments at 8.

[41] Southern at 14–15.

[42] NRECA reply comments at 18.

[43] Morgan Stanley reply comments at 10–11.

[44] APPA/TAPS reply comments at 11, NRECA reply comments at 13–14. The FTC filed comments in this proceeding in January 2006 on the contestable load test. FTC states that "the historical contestable load proposal fails to include a number of potentially important considerations in its framework for assessing horizontal market power, and the elements that it does include are not considered in an economically sound manner. In sum, the proposal does not represent an analytical advance over existing techniques to evaluate horizontal market power, and it falls far short of the economically sound framework for market power analysis presented in the Merger Guidelines." The FTC defines the following specific problems with the contestable load analysis: the price is not considered in the assessment of available supply, contractual and legal restrictions on supply are ignored, and the contestable load analysis ignores transmission discrimination and transmission constraints, which delineate the market.

[45] NRECA reply comments at 20–21.

for Commission consideration. Because the indicative screens are intended to screen out only those sellers that raise no horizontal market power concerns, as opposed to other sellers that raise concerns but may not necessarily possess horizontal market power, we find it appropriate to use conservative criteria and to rely on more than one screen. A conservative approach at the indicative screen stage of the proceeding is warranted because, if a seller passes both of the indicative screens, there is a rebuttable presumption that it does not possess horizontal market power.

63. The rebuttable presumption of horizontal market power that attaches to sellers failing one of the indicative screens is just that—a rebuttable presumption. It is not a definitive finding by the Commission; sellers are provided with several procedural options including the right to challenge the market power presumption by submitting a DPT analysis, or, alternatively, sellers can accept the presumption of market power and adopt some form of cost-based mitigation.[46] Accordingly, we will adopt the proposal to continue to use the two indicative screens and find that failure of either indicative screen creates a rebuttable presumption of market power. We reiterate our finding that ''[f]ailure to pass either of the indicative screens * * * will constitute a prima facie showing that the rates charged by the seller pursuant to its market-based rate authority may have become unjust and unreasonable and that continuation of the seller's market-based rate authority may no longer be just and reasonable.'' [47]

64. This approach, contrary to the claims of several commenters, will help to further competitive markets by allowing sellers without market power to sell power at market-based rates, and it will similarly give customers security that sellers that fail the screens are required to submit to further scrutiny and/or mitigation.

65. The pivotal supplier and market share indicative screens measure different aspects of market power. As the Commission stated in the April 14 Order, the uncommitted pivotal supplier indicative screen measures the ability of a firm to dominate the market at peak periods. The uncommitted market share analysis provides a measure as to whether a supplier may have a dominant position in the market, which is another indicator of potential unilateral market power and the ability of a seller to effect coordinated interaction with other sellers. The market share screen is also useful in measuring market power because it measures a seller's size relative to others in the market, in particular, the seller's share of generating capacity uncommitted after accounting for its obligations to serve native load. The market share screen provides a snapshot of these market shares in each season of the year. Taken together, the indicative screens can measure a seller's market power at both peak and off-peak times.[48] Both market share and pivotal supplier indicative screens are appropriate first steps for the Commission to use in determining if it needs a more robust analysis to determine whether the seller has market power. We conclude that having two screens as backstops to one another will better assist us in determining the existence of potential market power. Accordingly, we reject the suggestion of several commenters to abandon the market share indicative screen. We will retain both the pivotal supplier and market share indicative screens as described in the NOPR, as well as apply the rebuttable presumption of market power for those sellers that fail either indicative screen.[49]

66. In addition, the Commission will not adopt suggestions to alter the indicative screens in order to incorporate a contestable load analysis, as proposed by EEI and others. As noted by the FTC, APPA/TAPS, and NRECA, the contestable load analysis is flawed because, among other things, it does not consider control of generation through contracts. The Commission explained in the April 14 Order that the roles of the indicative screens are meant to be complementary. The pivotal supplier indicative screen indicates whether demand can be met without some contribution of supply by the seller at peak times, while the market share indicative screen indicates whether the seller has a dominant position in the market and may therefore have the ability to exercise horizontal market power, both unilaterally and in coordination with other sellers.[50] The contestable load analysis is essentially a variant on the pivotal supplier screen with differences in the calculation of wholesale load and the test thresholds, because, like the pivotal supplier screen, it addresses whether suppliers other than the seller can meet the demand in the relevant market. Therefore incorporating such an analysis would not improve our ability to establish a presumption of whether a seller has market power. The contestable load analysis therefore would add little useful information, and without the market share indicative screen, the Commission would have insufficient information because there would be no analysis of a seller's size relative to the other sellers in the market, and no information on the seller's market power during off-peak periods.

67. In addition, the contestable load analysis fails to consider the relative price of the competing supplies. Commenters have argued that if available non-applicant supply is at least twice the contestable load, the market is competitive. However, this analysis fails to consider whether the available non-applicant supply is competitively priced and, thus, in the market. This weakness in the contestable load analysis is addressed in the DPT analysis which considers only supply that is competitively priced.

68. We also reject arguments by E.ON U.S. and PNM/Tucson that the wholesale market share screen should be replaced because, they argue, it does not consider the size of the wholesale supply in the relevant market relative to the wholesale demand in that market. E.ON. U.S. and PNM/Tucson are requesting an analysis very similar to the contestable load analysis, whose defining characteristic is measuring the wholesale supply market relative to wholesale demand, which, as stated above, is essentially the same as the pivotal supplier screen, and would therefore add little useful information to the screening process.

69. We reject Duke's claim that because neither of the rationales originally cited by the Commission in support of the market share indicative screen—its ability to identify ''coordinating behavior,'' or its ability to detect the exercise of market power in off-peak periods—has been validated, the wholesale market share indicative screen is unnecessary. Specifically, the Commission believes that the ability of market participants to exercise market power through ''coordinating behavior'' is a legitimate concern under the FPA, in addition to the fact that it has long been recognized by the antitrust

[46] In the April 14 Order, the Commission stated that proposals for alternative mitigation in these circumstances could include cost-based rates or other mitigation that the Commission may deem appropriate. For example, a seller could propose to transfer operational control of enough generation to a third party such that the applicant would satisfy our generation market power concerns. April 14 Order, 107 FERC ¶ 61,018 at n. 142.

[47] April 14 Order, 107 FERC ¶ 61,018 at P 209.

[48] April 14 Order, 107 FERC ¶ 61,018 at P 72.

[49] As we noted in the July 8 Order, a number of those commenters that proposed eliminating the market share screen had supported it as a viable alternative in the past. July 8 Order, 108 FERC ¶ 61,026 at P 87.

[50] April 14 Order, 107 FERC ¶ 61,018 at P 72.

authorities.[51] The Commission also believes it is possible to exercise market power in off-peak periods because during such times the amount of supply in the market may be greatly reduced (*e.g.*, because of planned outages for plant maintenance), meaning that a seller that is not dominant at peak times might be at off-peak.

70. Moreover, we agree with APPA/TAPS that market-based rate assessments are used to determine the ability to exercise, not the exercise of, market power. The Commission need not wait passively until market power is exercised. Rather, it is incumbent on the Commission to set policies that will ensure that rates remain just and reasonable under section 205 of the FPA. Requiring sellers to submit screens that analyze the sellers' potential to exercise market power is consistent with such a policy.

71. We are unpersuaded by E.ON U.S.'s and PNM/Tucson's argument that ''false positives'' arising from the market share screen dampen the vigor of competitive wholesale market participation by unnecessarily curtailing the market-based rate authority of entities that, according to E. ON. U.S. and PNM/Tucson, lack market power. We recognize that a conservative screen may result in some false positives, but must weigh that against the cost of the false negatives that would occur if we adopted a less conservative screen or eliminated the market share indicative screen.

72. E.ON U.S. and PNM/Tucson, to support their point, cite several court cases in which market shares were alleged not to be reliable indicators of market power in regulated markets. However, the cases cited are not relevant to the issue of whether the Commission should retain the wholesale market share screen. The purpose of our indicative screens is to distinguish sellers that may raise horizontal market power concerns and those that do not; the market share screen is not the end of our horizontal market power analysis. In contrast, the cases cited by E.ON U.S. and PNM/Tucson [52] involve allegations of unlawful restraint of trade in violation of the Sherman Act,[53] a Federal antitrust statute prohibiting trade monopolies. The focus in such cases (whether a company has violated the Sherman Act) and the standard for making such a determination is different than the focus of the Commission at the indicative screen stage of the horizontal market power analysis (identifying sellers that require further horizontal market analysis without making a definitive finding regarding market power).

73. On both theoretical and practical grounds, we reject the argument by EEI and others that the market share indicative screen can diminish competition because some sellers that are the subject of a section 206 investigation choose mitigation rather than challenge the presumption of market power. First, mitigating a seller with market power ensures that the other sellers in the market cannot benefit from an artificially high market price due to the seller with market power exercising market power. Second, in our experience, sellers that choose mitigation rather than challenge the presumption of market power have market shares that are likely to indicate a dominant position in a geographic market.[54] In addition, many sellers have successfully rebutted the presumption of market power after failing one of the indicative screens.[55]

74. Further, we will not adopt the suggestion to substitute the HHI for the market share indicative screen or to supplement the indicative screens with the HHI. The indicative screens are used to separate sellers who are presumed to have market power from those that, absent extraordinary and transitory circumstances, clearly do not. We will not substitute the market share screen with an HHI screen because, as we have stated above, the seller's market share conveys useful information about its ability to exercise market power, so eliminating the market share screen in favor of the HHI could increase the risk of false negatives.[56] In addition, a high HHI can be the result of high market shares of sellers in the market other than the seller, and the focus of our analysis is on the seller's ability to exercise market power, so the HHI would provide little additional information to allow us to identify those sellers who clearly do not have market power. Finally, the HHI primarily provides information on the ability of sellers to exercise market power through coordinated behavior, while the market share screen primarily provides information on a particular seller's ability unilaterally to exercise market power. We will not supplement the indicative screens with the HHI screen because the indicative screens are sufficiently conservative to identify those sellers that have a rebuttable presumption of market power, without having to add an additional layer of review at the initial stage.

75. We clarify that sellers and intervenors may present alternative evidence such as a DPT study or historical sales and transmission data to support or rebut the results of the indicative screens. For example, intervenors could present evidence based on historical wholesale sales data or challenge the assumption that competing suppliers inside a balancing authority area have access to the market (such a challenge could take into account both the actual historical transmission usage at the time of the study as well as the amount of available transmission capacity at that time).[57] A seller may present evidence in support of a contention that, notwithstanding the results of the indicative screens, it does not possess market power.[58] However, sellers should not expect that the Commission will postpone initiating a section 206 investigation to protect customers while it examines this supplemental information if screen failures are indicated.[59] Nevertheless, the Commission may factor in this alternative evidence before deciding whether to initiate a section 206 investigation if the alternative evidence is appropriately supported, comprehensive and unambiguous, and

[51] *See* 1992 FTC/DOJ 1992 Horizontal Merger Guidelines sec. 2.1.

[52] *Cost Management*, 99 F.3d 937; *Rebel Oil*, 51 F.3d 1421; *S. Pac. Communications*, 740 F.2d 780; *MCI Communications*, 708 F.2d 1081; *Mid-Tex Communications*, 615 F.2d 1372; and *Almeda*, 615 F.2d 343.

[53] 15 U.S.C. 2, which states: ''Every person who shall monopolize, or attempt to monopolize, or combine or conspire with any other person or persons, to monopolize any part of the trade or commerce among the several States, or with foreign nations, shall be deemed guilty of a felony, and, on conviction thereof, shall be punished by fine not exceeding $100,000,000 if a corporation, or, if any other person, $1,000,000, or by imprisonment not exceeding 10 years, or by both said punishments, in the discretion of the court.''

[54] *See, e.g., Aquila, Inc.*, 112 FERC ¶ 61,307 (2005); *Carolina Power & Light Co.,* 113 FERC ¶ 61,130 (2005); *The Empire District Electric Co.,* 116 FERC ¶ 61,150 (2006); *MidAmerican Energy Co.*, 117 FERC ¶ 61,178 (2006); *Xcel Energy Services Inc.*, 117 FERC ¶ 61,180 (2006).

[55] *See, e.g., Kansas City Power and Light Co.*, 113 FERC ¶ 61,074 (2005); *PPL Montana, LLC*, 115 FERC ¶ 61,204 (2006); *PacifiCorp*, 115 FERC ¶ 61,349 (2006); *Tucson Electric Power Co.*, 116 FERC ¶ 61,051 (2006); *Acadia Power Partners, LLC*, 113 FERC ¶ 61,073 (2005).

[56] For example, in a market with one seller with a 35 percent market share and 13 sellers each with 5 percent market shares, the HHI would be 1,550 (1,225 + 13(25)), which would not fail the 2,500 HHI threshold or even the proposed lower 1,800 HHI threshold. In such a market, a firm with a 35 percent market share could have the ability to exercise market power, which would not be picked up by an HHI screen.

[57] *Id.* at P 37.

[58] *Id.* at n. 11.

[59] *See, e.g., LG&E Energy Mtkg. Inc.*, 111 FERC ¶ 61,153 at P 21, 22 (2005); *Tampa Electric Co.*, 110 FERC ¶ 61,206 at P 24, 25 (2005); *Entergy Services, Inc.*, 109 FERC ¶ 61,282 at P 36 (2004).

conducive to prompt review by the Commission.

76. We will not adopt Southern's suggestion that the indicative screens be made voluntary. We will continue to require that sellers submit the indicative screens or concede the presumption of market power before they file a DPT. However, as discussed above, a seller may submit with its indicative screens a DPT as alternative evidence. As stated above, submission of a DPT analysis as alternative evidence at the same time a seller submits the indicative screens may result in the Commission instituting a section 206 proceeding to protect customers, based on failure of an indicative screen, while the Commission considers the merits of the DPT analysis.

77. We do not agree with Southern's view that failure of the indicative screen(s) does not provide a sufficient basis to establish a rebuttable presumption of market power. The indicative screens are intended to identify the sellers that raise no horizontal market power concerns and can otherwise be considered for market-based rate authority. Sellers failing one or both of the indicative screens, on the other hand, are identified as sellers that potentially possess horizontal market power and for which a more robust analysis is required. The uncommitted pivotal supplier screen focuses on the ability to exercise market power unilaterally. Failure of this screen indicates that some or all of the seller's generation must run to meet peak load. The uncommitted market share analysis indicates whether a supplier has a dominant position in the market. Failure of the uncommitted market share screen may indicate the seller has unilateral market power and may also indicate the presence of the ability to facilitate coordinated interaction with other sellers. It is on this basis that we find that a rebuttable presumption of market power is warranted when a seller fails one or both of the indicative screens. However, we agree with Southern that the DPT is a more definitive means for determining the existence of market power. As a result, we allow sellers that have failed one or both of the indicative screens to rebut the presumption of market power by performing the DPT. Further, because failure of one or both of the indicative screens only creates a rebuttable presumption of market power and sellers have a Commission-endorsed analysis that they can use to rebut that presumption (the DPT), we find without merit Southern's view that the indicative screens create *a priori* evidentiary presumption of guilt, are improper, and create due process concerns.

78. With regard to Southern's suggestion that we use the DPT as the default test, we find that if we were to do so our ability to protect customers while the analysis is evaluated could be compromised. The DPT is a more involved and complex analysis. The Commission has also at times set a DPT analysis for evidentiary hearing which greatly extends the time between when the DPT is submitted to the Commission and when a final decision is rendered. The rates customers are subject to during the time period before the issuance of a Commission order addressing a seller's DPT would not be subject to refund and, accordingly, the customers would be unprotected if the seller ultimately is found to have market power. However, under our current policy, and as adopted herein, if a seller wishes to file a DPT rather than the indicative screens it may do so. In doing so, the seller concedes that it fails the indicative screens, which concession establishes a rebuttable presumption of market power, and the Commission will issue an order initiating a section 206 proceeding to investigate whether the seller has market power and establishing a refund effective date for the protection of customers while the Commission evaluates the filed DPT. In the case of a seller that concedes the failure of one or both of the screens and submits the DPT in the same filing, the Commission is able to establish a refund effective date at an earlier time than if the seller were able to skip the screen stage entirely and file a DPT without conceding a screen failure.

79. We will reject Southern's request that forced outages be deducted from capacity. As we stated in the July 8 Order, ''forced outages are non-recurring events that do not reflect normal operating conditions.''[60] Allowing deduction of forced outages will generally not change indicative screen results, because all sellers will be able to deduct forced outages, offsetting each other. In the unlikely event that forced outage numbers were not completely offsetting, allowing forced outages in the indicative screens would benefit owners of relatively unreliable fleets at the expense of owners of relatively reliable fleets.

[60] July 8 Order, 108 FERC ¶ 61,026 at P 68.

2. Indicative Market Share Screen Threshold Levels and Pivotal Supplier Application Period

Commission Proposal

80. In the NOPR, the Commission proposed to retain the 20 percent threshold for the wholesale market share screen (*i.e.*, with a market share of less than 20 percent, the seller would pass the screen). The Commission stated that since the screens are indicative, not definitive, a relatively conservative threshold for passing them was appropriate. Indeed, pursuant to the horizontal market power analysis, the Commission will not make a definitive finding that a seller has market power unless and until the more robust analysis, the DPT, is considered.

81. The Commission proposed to continue the use of annual peak load in the pivotal supplier analysis and not to expand the pivotal supplier analysis to include monthly assessments. It stated that the pivotal supplier analysis examines the seller's market power during the annual peak, and that the hours near that point in time are the most likely times that a seller will be a pivotal supplier.

a. Market Share Threshold

Comments

82. A number of commenters argue that 20 percent is too low a threshold for the market share indicative screen. Some point out that, given native load requirements, it is very difficult for investor-owned utilities outside of RTOs/ISOs to fall below the 20 percent threshold for the market share indicative screen.[61] Duke also notes that the 20 percent criterion is incompatible with regional planning requirements because, according to Duke, the amount of capacity needed to satisfy regional planning reserve margins ''would place the utility at substantial risk of exceeding the 20 percent threshold.''[62]

83. E.ON U.S. argues that, because the courts have not considered a 20 percent market share to indicate a market power concern, associating a market share indicative screen failure with a presumption of market power is inappropriate.[63] Additionally, Progress

[61] *See*, *e.g.*, Southern at 8–9, Duke at 15–16, EEI at 8–9.

[62] Duke at 17.

[63] *See* E.ON U.S. at 14–15, n.18, *citing PepsiCo, Inc.* v. *Coca-Cola Co.*, 315 F.3d 101, 109 (2d Cir. 2003) (''Absent additional evidence, such as an ability to control prices or exclude competition, a 64 percent market share is insufficient to infer monopoly power.''); *AD/SAT* v. *Associated Press*, 181 F.3d 216, 229 (2d Cir. 1999) (concluding that 33 percent market share is insufficient to show a dangerous probability of monopoly power); *United*

Continued

Energy argues that it is inappropriate to associate failure of the market share screen with a presumption of market power when U.S. Department of Justice (DOJ) merger guidelines state that only firms with 35 percent or more market share have market power.[64]

84. PPL states that it agrees that the 20 percent threshold should be replaced by a 35 percent threshold in the market share screen and argues that such an increase will avoid the false-positive failure rate of the indicative screens, and the cost, time and repercussions in the financial markets of the extended pendency of a market-based rate renewal proceeding while a DPT is conducted and considered.[65]

85. In reply, APPA/TAPS state that there is no reason to raise the market share indicative screen threshold above 20 percent simply because investor-owned utilities have trouble passing the market share indicative screen.[66] NRECA and TDU Systems note that the factors that EEI believes make it difficult to pass the indicative screens—a large amount of reserves and little available transfer capability—are precisely the factors to consider when evaluating whether a market is competitive.[67]

86. Rather than raising the threshold level, TDU Systems propose to lower the threshold to 15 percent for the market share indicative screen, claiming that 20 percent was never justified by the Commission or shown to be the right balance.[68] Citing Commission and judicial precedent, TDU Systems also note that the grant of market-based rate authority cannot be made without the discipline of market forces.[69]

87. These commenters cite a recent decision of the U.S. Court of Appeals for the Ninth Circuit [70] to buttress their positions, arguing that even market shares lower than 20 percent can lead to market manipulation.

88. In reply to these arguments, Duke states that certain commenters' reliance on this is mistaken because that decision addressed market manipulation, not market power.[71] Duke asserts that virtually any supplier, regardless of its market share, has some ability to manipulate market outcomes by engaging in anomalous bidding practices.

Commission Determination

89. The Commission will retain the 20 percent market share threshold for the indicative market share screen. EEI and others argue that the Commission should use a 35 percent threshold as a presumption of market power because the DOJ merger guidelines state that only firms with 35 percent or more market share have market power. As the Commission stated in the July 8 Order, however, in a market comprised of five equal-sized firms with 20 percent market shares, the HHI is 2,000, which is above the DOJ/FTC HHI threshold of 1,800 for a highly concentrated market, and in markets for commodities with low demand price-responsiveness like electricity, market power is more likely to be present at lower market shares than in markets with high demand elasticity.[72] Therefore, we will retain a conservative 20 percent threshold for this indicative screen.

90. When arguing that a 20 percent threshold for the market share screen is too low, E.ON. U.S. and PNM/Tucson ignore that the indicative screens are based on uncommitted capacity, not total capacity. When calculating uncommitted capacity for the market share screen, a seller deducts from its total capacity the capacity dedicated to long-term sales contracts, operating reserves,[73] planned outages, and native load [74] as measured by the appropriate native load proxy. As a result, a substantial amount of seller capacity may not be counted in measures of market share. Therefore, it is inappropriate to compare market shares based on uncommitted capacity to the market shares in the cases that E.ON. U.S. and PNM/Tucson cite.

91. We further note that other commenters have argued that the 20 percent threshold is too high. We disagree. The 20 percent threshold is meant to strike a balance between having a conservative but realistic screen and imposing undue regulatory burdens. The Commission's experience in the context of market-based rate proceedings demonstrates this point. In the three years since the April 14 Order, the Commission has revoked the market-based rate authority of two sellers, thirteen sellers relinquished their market-based rate authority, and six companies satisfied the Commission's concerns for the grant of market-based rate authority at the DPT phase. In addition, intervenors have the opportunity to present other evidence such as historical data in order to rebut the presumption that sellers lack market power.[75] Moreover, no commenter advocating a 15 percent threshold for the market share has shown why it is superior to the current 20 percent threshold. Therefore, we find that the 20 percent market share threshold strikes the right balance in seeking to avoid both "false negatives" and "false positives" and we will not reduce the wholesale market share screen to 15 percent, as suggested by TDU Systems.

92. The Commission does not accept Duke's assertion that the market share indicative screen is incompatible with regional planning requirements. The April 14 Order allows operating reserves necessary for reliability, as determined by State or regional reliability councils,[76] to be deducted from total capacity attributed to the seller.

93. We also reject the argument that the 20 percent threshold is too low because of native load obligations of investor-owned utilities outside of RTOs. First, the calculation of 20 percent is the same regardless of whether a seller is located in an RTO or not. Second, as discussed herein, we allow for a native load deduction in the wholesale market share screen and are increasing the deduction to address concerns raised by investor-owned utilities and others. Given the increased native load deduction, our market share screen adequately incorporates investor-owned utilities' native load obligations while necessarily maintaining the conservative nature of the screens.

b. Pivotal Supplier Application Period

Comments

94. Some commenters recommend that the pivotal supplier indicative screen should be applied monthly, rather than just in a seller's peak month. They reason that sellers, though not pivotal in the highest demand period, might be pivotal at different times of the year or in off-peak periods, such as in the spring or fall when power plants are on planned outages.[77]

Commission Determination

95. The Commission will not require the pivotal supplier indicative screen to be applied monthly, as some commenters suggest, because we believe

*Air Lines, Inc.* v. *Austin Travel Corp.*, 867 F.2d 737, 742 (2d Cir. 1989) (finding that 31 percent market share does not constitute a national monopoly).

[64] Progress Energy at 7, citing EEI at 6–10.

[65] PPL reply comments at 7.

[66] APPA/TAPS reply comments at 12.

[67] NRECA reply comments at 16, TDU Systems reply comments at 10, citing EEI at 8.

[68] TDU Systems at 7.

[69] TDU Systems at 5.

[70] *Pub. Utils. Comm'n of Calif.* v. *FERC*, 462 F.3d 1027, at 1039 (9th Cir. 2006) (*CPUC*) ("As became clear in hindsight, even those who controlled a relatively small percentage of the market [in the California market during 2000 and 2001] had sufficient market power to skew markets artificially.").

[71] Duke reply comments at 18, citing *CPUC*.

[72] July 8 Order, 108 FERC ¶ 61,026 at P 96.

[73] April 14 Order 107 FERC ¶ 61,018 at P 94.

[74] *Id.* at P 100.

[75] *Id.* at P 97.

[76] April 14 Order, 107 FERC ¶ 61,018 at P 96.

[77] See, *e.g.* APPA/TAPS at 66–67, NRECA at 19–20.

it is unnecessary and overly burdensome to do so. Even though conditions of tight supply may occur at other times of the year or in abnormal operating conditions, the combination of the pivotal supplier analysis and the wholesale market share screen is sufficient, because suppliers with market power at such times are also likely to fail at least one of these screens. Moreover, if intervenors believe that a seller is pivotal during non-peak periods, they are permitted to file evidence to that effect. Accordingly, using only the peak month in the pivotal supplier indicative screen is appropriate. We note that if a seller fails the indicative screens and submits a DPT, it is required to provide a pivotal supplier analysis for each season and for both peak and non-peak hours.

3. DPT Criteria

Commission Proposal

96. With regard to the DPT analysis, the Commission proposed to retain the current thresholds (20 percent for the market share analysis and 2,500 for the HHI analysis), as well as the current practice of weighing all the relevant factors presented in determining whether a seller does or does not have horizontal market power. The Commission proposed to continue to do so on a case-by-case basis, weighing such factors as available economic capacity, economic capacity, market share, HHIs, and historical sales and transmission data.[78]

Comments

97. Several commenters suggest changes to the DPT criteria. One suggested change is to emphasize[79] or rely exclusively[80] on the available economic capacity measure, in order to properly account for native load. For example, one commenter argues that the economic capacity prong of the DPT analysis is not a useful indicator of the presence or absence of market power when applied to vertically integrated utilities in their home control areas because that analysis completely disregards native load obligations, making this prong virtually unpassable by such utilities. This commenter also notes that even using the available economic capacity measure, a seller with a market share above 35 percent would fail the DPT ''even though there is no real market power problem because the in-area wholesale customers have access to ample supplies of competitively priced power.''[81] In this regard, he argues that the DPT should be changed to take into account ''competitive alternatives available for wholesale customers.''[82]

98. Several other commenters disagree with the 2,500 HHI threshold for the DPT. Some reason that a 2,500 HHI threshold is not well justified and that an 1,800 HHI threshold is more appropriate because this is the criterion used in a highly concentrated market. They argue that if a 2,500 HHI threshold is used, it should be used with a 15 percent market share because these are the criteria of the oil-pipeline test from which the HHI 2,500 criterion is obtained.[83] State AGs and Advocates note that the Commission has never systematically attempted to correlate the results of the pivotal supplier indicative screen, the market share indicative screen, or the DPT (including HHI results) proposed in the NOPR with actual independently derived data and measures as to the existence of market power in any wholesale electricity market in the U.S.[84] Without having done this type of systematic and quantitative evaluation of the proposed market power tests based on some type of independent verification, State AGs and Advocates contend that the Commission cannot be confident that the three proposed tests are reasonably accurate and, therefore, useful tests to determine the existence of market power in any electricity market. For example, State AGs and Advocates ask how the Commission knows if an HHI corresponds to the point at which market power begins, and whether it varies by factors such as input price, generation mix and different market structures through the country.[85]

99. Furthermore, State AGs and Advocates claim that the DPT is not an adequate tool for assessing market power ''in any context.'' First, they state that the DPT will not discern bidding strategies of different suppliers. In addition, they assert that a DPT does not consider the differences between fundamentally different types of market structures: short-term energy only markets, short-term capacity markets, ancillary service markets, and long-term contract markets for energy and capacity.[86]

100. A number of commenters believe that the HHI threshold sufficient for passage of the DPT should remain at 2,500.[87] PPL states that lowering the HHI threshold to 1,800 will cause more false positives and direct capital away from the generation sector.

101. EEI and Progress Energy recommend that only the pivotal supplier and HHI analyses of the DPT should be retained, particularly if the market share analysis under the indicative screens is retained. They argue that the pivotal supplier and HHI analyses are more than sufficient to determine whether the potential for market power exists.[88]

102. A few commenters are skeptical about the need for a DPT. Southern states that ''granting market-based rates should not require the same analysis as for a merger,'' and that the Commission should reconsider using the DPT.[89] In this regard, Southern argues that unlike mergers, which are difficult and costly to undo, the Commission has the ability to continuously police the exercise of market power. Further, Southern states that the Energy Policy Act of 2005 provides for stiff civil and criminal penalties. Southern adds that the Commission recently issued new rules against market manipulation to thwart exercises of market power.

103. AARP expresses concern about the lack of competition in wholesale electric markets. It argues that market-based rate reviews are intended to determine whether the seller's market-based rates will be just and reasonable, not whether a seller passes the various tests. AARP argues that real-world evidence that may not fit neatly within the specified market-based rate criteria must be considered before the Commission can conclude that a seller lacks market power. AARP states that, as the NOPR recognizes (PP 63–64), both historical and forward-looking evidence should be considered.

Commission Determination

104. The Commission will continue to use the DPT for companies that fail the

[78] *Economic capacity* means the amount of generating capacity owned or controlled by a potential supplier with variable costs low enough that energy from such capacity could be economically delivered to the destination market. *Available economic* capacity means the amount of generating capacity meeting the definition of economic capacity less the amount of generating capacity needed to serve the potential supplier's native load commitments. *See generally* April 14 Order, 107 FERC ¶ 61,018 at Appendix F.

[79] Dr. Pace at 9.

[80] Southern at 20–21, EEI at 15.

[81] Dr. Pace at 11–12.

[82] Dr. Pace at 12–13.

[83] APPA/TAPS at 78–79, TDU Systems at 18, Montana Counsel at 15 (referring to APPA/TAPS comments).

[84] State AGs and Advocates state that by ''independently'' derived measures of market power they mean measures derived using different methodologies (and more accurate methodologies) than the Commission proposed in the NOPR.

[85] States AGs and Advocates at 36–37.

[86] State AGs and Advocates reply comments at 6–7.

[87] MidAmerican reply comments at 2, citing EEI comments; PPL reply comments at 8; EEI reply comments at 23.

[88] EEI at 10–12, Progress at 8.

[89] Southern at 19–20.

market power indicative screens. The DPT is a well-established test that has been used routinely by the Commission to analyze market power in the merger context. The fact that it is used in section 203 cases does not demonstrate that it is inappropriate for market-based rate cases. Rather, it provides a well-established tool for assessing market power that is known and widely used in the electric industry. Moreover, in both contexts, the DPT allows for the calculation of market shares and market concentration values under a wide range of season and load conditions.

105. Sellers failing one or more of the initial screens will have a rebuttable presumption of market power. If such a seller chooses not to proceed directly to mitigation, it must present a more thorough analysis using the DPT. The DPT is also used to analyze the effect on competition for transfers of jurisdictional facilities in section 203 proceedings,[90] using the framework described in Appendix A of the Merger Policy Statement and revised in Order No. 642.[91]

106. The DPT defines the relevant market by identifying potential suppliers based on market prices, input costs, and transmission availability, and calculates each supplier's economic capacity and available economic capacity for each season/load condition.[92] The results of the DPT can be used for pivotal supplier, market share and market concentration analyses.

107. Using the economic capacity for each supplier, sellers should provide pivotal supplier, market share and market concentration analyses. Examining these three factors with the more robust output from the DPT will allow sellers to present a more complete view of the competitive conditions and their positions in the relevant markets.

108. Under the DPT, to determine whether a seller is a pivotal supplier in each of the season/load conditions, sellers should compare the load in the destination market to the amount of competing supply (the sum of the economic capacities of the competing suppliers). The seller will be considered pivotal if the sum of the competing suppliers' economic capacity is less than the load level (plus a reserve requirement that is no higher than State and Regional Reliability Council operating requirements for reliability) for the relevant period. The analysis should also be performed using available economic capacity to account for sellers' and competing suppliers' native load commitments. In that case, native load in the relevant market would be subtracted from the load in each season/load period. The native load subtracted should be the average of the native load daily peaks for each season/load condition.

109. Each supplier's market share is calculated based on economic capacity. The market shares for each season/load condition reflect the costs of the sellers' and competing suppliers' generation, thus giving a more complete picture of the sellers' ability to exercise market power in a given market. For example, in off-peak periods, the competitive price may be very low because the demand can be met using low-cost capacity. In that case, a high-cost peaking plant that would not be a viable competitor in the market would not be considered in the market share calculations, because it would not be counted as economic capacity in the DPT. Sellers must also present an analysis using available economic capacity and explain which measure more accurately captures conditions in the relevant market.

110. Under the DPT, sellers must also calculate the market concentration using the HHI based on market shares.[93] HHIs have been used in the context of assessing the impact of a merger or acquisition on competition. However, as noted by the U.S. Department of Justice in the context of designing an analysis for granting market-based pricing for oil pipelines, concentration measures can also be informative in assessing whether a supplier has market power in the relevant market. ''The Department and the Commission staff have previously advocated an HHI threshold of 2,500, and it would be reasonable for the Commission to consider concentration in the relevant market below this level as sufficient to create a rebuttable presumption that a pipeline does not possess market power.'' [94]

111. A showing of an HHI less than 2,500 in the relevant market for all season/load conditions for sellers that have also shown that they are not pivotal and do not possess a 20 percent or greater market share in any of the season/load conditions would constitute a showing of a lack of market power, absent compelling contrary evidence from intervenors. Concentration statistics can indicate the likelihood of coordinated interaction in a market. All else being equal, the higher the HHI, the more firms can extract excess profits from the market. Likewise a low HHI can indicate a lower likelihood of coordinated interaction among suppliers and could be used to support a claim of a lack of market power by a seller that is pivotal or does have a 20 percent or greater market share in some or all season/load conditions. For example, a seller with a market share of 20 percent or greater could argue that that it would be unlikely to possess market power in an unconcentrated market (HHI less than 1,000). As with our initial screens, sellers and intervenors may present evidence such as historical wholesale sales. Those data could be used to calculate market shares and market concentration and could be used to refute or support the results of the DPT. The Commission encourages the most complete analysis of competitive conditions in the market as the data allow.

112. We will continue to weigh both available economic capacity and economic capacity when analyzing market shares and HHIs. Based on our substantial experience in applying the DPT over the past decade, we have found that both analyses are useful indicators of suppliers' potential to exercise market power, and we are unwilling to rely solely on one measure or the other.[95] For example, in markets where utilities retain significant native load obligations, an analysis of available economic capacity may more accurately assess an individual seller's competitiveness, as well as the overall competitiveness of a market, because available economic capacity recognizes the native load obligations of the sellers. On the other hand, in markets where the

[90] 16 U.S.C. 824b (2000).

[91] Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement, Order No. 592, 61 FR 68,595 (1996), FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 ¶ 31,044 (1996), *reconsideration denied*, Order No. 592–A, 62 FR 33,341 (1997), 79 FERC ¶ 61,321 (1997) (Merger Policy Statement); *see also* Revised Filing Requirements Under Part 33 of the Commission's Regulations, Order No. 642, 65 FR 70,983 (2000), FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 ¶ 31,111 (2000), *order on reh'g*, Order No. 642–A, 66 FR 16,121 (2001), 94 FERC ¶ 61,289 (2001).

[92] Super-peak, peak, and off-peak, for Winter, Shoulder and Summer periods and an additional highest super-peak for the Summer.

[93] The HHI is the sum of the squared market shares. For example, in a market with five equal size firms, each would have a 20 percent market share. For that market, HHI = $(20)^2 + (20)^2 + (20)^2 + (20)^2 + (20)^2 = 400 + 400 + 400 + 400 + 400 = 2{,}000$.

[94] *See* Comments of the United States Department of Justice in response to Notice of Inquiry Regarding Market-Based Ratemaking for Oil Pipelines, Docket No. RM94–1–000 (January 18, 1994).

[95] *See, e.g., Tampa Electric Company,* 117 FERC ¶ 61,311 (2006); *PacifiCorp,* 115 FERC ¶ 61,349 (2005); *Tucson Electric Power Company,* 116 FERC ¶ 61,051(2006); *Duke Power, a Division of Duke Energy Corporation,* 111 FERC ¶ 61,506 (2005); and *Kansas City Power and Light Company,* 113 FERC ¶ 61,074 (2005).

sellers have been predominantly relieved of their native load obligations, an analysis of economic capacity may more accurately reflect market conditions and a seller's relative size in the market.

113. Likewise, we find the HHI market concentration measure to be useful in assessing the market power of individual sellers, and it complements the market share and pivotal supplier measures in the DPT stage of the analysis. Furthermore, no commenter has presented a compelling argument for why the Commission should lower or raise the HHI threshold in the DPT. Accordingly, we will retain 2,500 as the appropriate threshold for passing this part of the DPT for the reasons we stated in the April 14 Order.[96] We will not adopt the suggestion to lower the market share threshold to 15 percent from 20 percent, for the reasons set forth above, in the NOPR and July 8 Order.[97] Commenters have presented no compelling reason to do so, and in our experience since the April 14 Order, we have not seen cases where the HHI was over 2,500 and the seller's market share was between 15 and 20 percent, which would be the type of situation about which APPA/TAPS and others are concerned. Accordingly, such a reform would not likely result in additional findings of market power.

114. State AGs and Advocates claim that the DPT is not an adequate tool for assessing market power because it will not discern bidding strategies of different suppliers. However, State AGs and Advocates miss the point of the analysis: by determining whether a seller has capacity that can compete in the market under various season and load conditions, the DPT provides an accurate picture of market conditions. Examining market conditions allows the Commission to determine whether a seller has market power. The DPT does this by examining short-term energy markets and, in particular, sellers' available generation capacity. In addition, absent entry barriers, and a specific finding of market power, the Commission has said that long-term markets are competitive. With regard to ancillary services, as discussed herein, the Commission requires market power analyses for those services to support a request for market-based rate authority. Assessing competing suppliers' bidding strategies, ex ante, would not illuminate the state of the market and the ability of sellers to alter prices within it.

115. We also reject Southern's argument that the DPT analysis is unnecessary because of the Commission's enhanced civil penalty authority and continuing policing of sellers with market-based rate authorization. While those are critical components of our program to ensure just and reasonable market-based rates, they are not a substitute for an analysis of the potential market power of sellers seeking market-based rate authority. In addition, Southern's argument that rules against market manipulation will thwart all exercises of market power is speculative.

116. We will not change the DPT to take into account competitive alternatives available for wholesale customers as proposed by a commenter. We stated above our reasons for rejecting use of a contestable load analysis in the indicative screens, and we reject it for the DPT for the same reasons.

117. AARP and State AGs and Advocates argue that the Commission should consider evidence from actual market data in determining whether market power exists rather than rely on the results of the DPT to determine whether a seller has market power. We agree that actual market data is an important part of a determination of whether a seller may have market power. In this regard, we look at actual market data, both in the initial analysis and in ongoing monitoring of the EQR data. As the Commission stated in the April 14 Order, ''[a]s with our initial screens, applicants and intervenors may present evidence such as historical wholesale sales. Those data could be used to calculate market shares and market concentration and could be used to refute or support the results of the Delivered Price Test.'' [98] In addition, as part of our ongoing monitoring activities, we examine the EQR data in an effort to identify whether market prices may indicate an exercise of market power.

4. Other Products and Models

Comments

118. ELCON expresses concern over the entire horizontal market power analysis process: indicative screens, followed by DPT or mitigation for those that fail the indicative screens. ELCON notes that the evolution of these practices generally occurred in a series of highly contested proceedings, and did not benefit from the broader and more balanced review afforded by a generic rulemaking. ELCON states that its concern is that the practices unduly shift the burden of proof to potential victims of market power abuse. This concern would only be academic, ELCON continues, if the market structures were truly competitive and there were strong structural protections against the exercise of market power. But the hybrid nature of most regional markets, combined with inadequate infrastructure, creates an environment that discourages trust in market outcomes.[99]

119. Some commenters urge the Commission to allow different product definitions, *e.g.*, short-term power and long-term power, in the calculation of the indicative screens and the DPT. For example, NRECA argues that the Final Rule must require sellers to identify the relevant product markets, including the distinct products for which they seek market-based rate authority, and demonstrate that they lack market power in those product markets.[100] The Montana Counsel argues that the Commission's screens and DPT analysis models measure market power during certain test days for current time periods,[101] and that capacity that is available to make short-term energy sales may not be available for long-term, firm power sales. Thus, the Montana Counsel asserts that the Commission may not rely exclusively on short-term or spot markets to measure whether there are competitive long-term markets.

120. Other commenters remain divided over whether long-term power markets should be included in the market power analysis. PPL urges that long-term markets should not be considered in a market power analysis because of infeasibility and also because it violates the Commission's precedent that there is no long-term market power unless there exist barriers to entry.[102] In contrast, NRECA and TDU Systems state that long-term markets need to be analyzed in the market power analysis because monopolies will probably persist into the future for many consumers [103] and these consumers need protection. TDU Systems suggest using an installed capacity indicative screen for long-term markets.[104]

121. State AGs and Advocates and NASUCA suggest that the Commission adopt behavioral modeling, such as

[96] April 14 Order, 107 FERC ¶ 61,018 at P 111 (explaining that at less than 2,500 HHI in the relevant market for all season/load conditions there is little likelihood of coordinated interaction among suppliers in a market).

[97] July 8 Order at P 95–97 and NOPR at P 41.

[98] April 14 Order, 107 FERC ¶ 61,018 at P 112.

[99] ELCON at 4–5.

[100] NRECA at 16–18.

[101] Montana Counsel at 5–8.

[102] PPL reply comments at 2–3 and n.6, citing *Exelon Corp.,* 112 FERC ¶ 61,011 at P 136 (2005).

[103] NRECA reply comments at 11, TDU Systems reply comments at 5–7.

[104] TDU Systems reply comments at 9.

game theory, rather than structural analysis, because the latter cannot capture market power behavior.[105] NASUCA suggests that the Commission hold a technical conference to consider behavioral modeling. Duke disagrees with NASUCA's and others' calls for behavioral models, contending that they are theoretically complex and data-intensive and do not meet the prerequisite of being simple, easily understood and readily verifiable by the Commission.

Commission Determination

122. We will not generically alter the indicative screens or the DPT to allow different product analyses for short-term or long-term power as some commenters suggest. As the Commission has stated in the past, absent entry barriers, long-term capacity markets are inherently competitive because new market entrants can build alternative generating supply. There is no reason to generically require that the horizontal analysis consider those products that are affected by entry barriers. Instead, we will consider intervenors' arguments in this regard on a case-by-case basis.

123. We reject ELCON's contentions regarding the development of our horizontal market power analysis. While the screens and DPT criteria did arise out of specific cases, there have been numerous opportunities in this rulemaking for interested parties to express any concerns and propose alternatives, including technical conferences and numerous rounds of written comments. We believe that this rulemaking has given all interested parties ample opportunity to voice any and all options for revising the screens and DPT criteria and proposing alternatives, and has given us the opportunity to evaluate whether these tools remain appropriate. We conclude that they do.

124. Finally, we will not adopt the suggestion by some commenters that behavioral modeling be used in addition to, or in place of, the indicative screens and the DPT. Although game theory has been used in laboratory experiments and in theoretical studies where the number of players and choices available to players are limited, we do not consider it a practical approach for the volume of analyses we must perform, particularly since a vast amount of choices are available and many of those are unobservable. The data gathering and analysis burden imposed on sellers and the Commission would be overly burdensome and impractical.

5. Native Load Deduction

a. Market Share Indicative Screen

Commission Proposal

125. To reduce the number of ''false positives'' in the wholesale market share indicative screen, the Commission proposed in the NOPR to adjust the native load proxy for this screen. The Commission proposed to change the allowance for the native load deduction under the market share indicative screen from the minimum native load peak demand for the season to the average native load peak demand for the season. This change makes the deduction for the market share indicative screen consistent with the deduction allowed under the pivotal supplier indicative screen.

Comments

126. TDU Systems argue that the Commission provides no empirical evidence supporting this change—*i.e.*, no evidence of an excessive number of false positives produced by the Commission's current policy. TDU Systems also state that the Commission does not explain why it believes its current proxy ''results in too much uncommitted capacity attributable to the seller.'' [106] In particular, TDU Systems state that the Commission does not explain what factors it used to determine the appropriate level of uncommitted capacity to which it compared the current proxy.

127. APPA/TAPS agree, adding that the Commission proposal appears to be a results-driven effort to eliminate the need for some public utilities to submit a DPT.[107] APPA/TAPS argue that the Commission's ''false positives'' justification loses sight of the stakes involved in the market-based rate determination. They state that the price of a false positive associated with the initial screens will be the seller's submission of the DPT. APPA/TAPS argue that that price pales in comparison to the unreasonably high prices and market power exercise that can result from a false negative. According to APPA/TAPS, it is thus entirely appropriate for the Commission to take a closer look when a utility fails the initial screens, even when the Commission ultimately allows market-based rate authorization.[108]

128. In addition, APPA/TAPS state that, as well as lacking evidentiary basis, the proposed adjustment is not based on sound economic principles. APPA/TAPS argue that when the Commission originally adopted the native load proxy for the market share screen, it said the screen should reflect ''all of the capacity that is available to compete in wholesale markets at some point during the season.'' [109] APPA/TAPS state that now the Commission proposes to eliminate even more of the capacity that is available to compete at some point in the season by increasing the proxy to the average native load peak demand for the season.

129. APPA/TAPS further argue that adoption of the Commission's proposal would mean that the market-based rate screens would make no assessment of off-peak periods, even though the Commission has said that the market share screen is intended to measure market power during off-peak times.[110] They state that ''screens should examine market power for the on-peak and off-peak periods of the different seasons.'' [111]

130. Finally, APPA/TAPS argue that consistency across the two screens defeats the purpose of having more than one screen. The market share screen is intended to reflect capacity that could compete, including during off-peak periods. By contrast, the pivotal supplier screen is specifically intended to measure market power risks at system peak.

131. APPA/TAPS offer that if the Commission nonetheless believes some consistency is desired it can achieve it by using a native load proxy for the market share screen based upon the average minimum loads. Such a proxy would be consistent with the Commission's original intent of a screen that identifies ''all of the capacity that is available to compete in wholesale markets at some point during the season.'' [112]

132. Other commenters generally support the Commission's proposal to use seasonal average native load as the native load proxy for the market share indicative screen. Many state that the proposed native load proxy is a more accurate representation of native load obligations.[113] Several commenters

[105] State AGs and Advocates at 29–30, NASUCA at 14–15.

[106] TDU Systems at 13.

[107] APPA/TAPS at 68, citing *Acadia Power Partners LLC,* 111 F.E.R.C. ¶ 61,239 (2005), and *Kansas City Power & Light Co.,* 111 FERC ¶ 61,395 (2005), where the applying utilities failed the market share screen, but passed the pivotal supplier screen. In both cases, the company opted to submit a DPT, and after consideration, the Commission allowed the utilities to retain their market-based rate authority. *Acadia Power Partners, LLC,* 113 FERC ¶ 61,073 (2005); *Kansas City Power & Light Co.,* 113 FERC ¶ 61,074 (2005).

[108] APPA/TAPS at 68–70.

[109] APPA/TAPS at 69, citing April 14 Order, 107 FERC ¶ 61,018 at P 92.

[110] April 14 Order, 107 FERC ¶ 61,018 at P 72.

[111] APPA/TAPS at 70, citing Kirsch SMA Affidavit at 8–9.

[112] April 14 Order, 107 FERC ¶ 61,018 at P 92.

[113] *See, e.g.*, Ameren at 3, FirstEnergy at 4–5.

suggest excluding weekends and holidays from the proxy native load calculation because these periods are not representative of normal load hours.[114]

133. EEI argues that even with this proposed change, the generation capacity required by a utility to serve its native load is still being understated.[115] It states that utilities are required to meet the peak demands of their native load customers plus maintain a reserve margin for reliability purposes. This requirement directly determines the amount of generation capacity that a supplier can commit to the wholesale opportunity sales market. As such, EEI argues that the change proposed in the NOPR is a step in the right direction in terms of more accurately recognizing the amount of generation capacity required by a utility to meet native load requirements, but still understates the actual requirements.

134. EEI contends that from a generation planning perspective, no one with any expertise in that area doubts the native load proxy described in the April 14 Order underestimates the amount of capacity that a supplier needs to meet native load requirements and therein both overstates the amount of capacity that the supplier has to compete in the wholesale market as well as the supplier's market share. As a result of this overestimation of the capacity that a supplier would have to compete in the wholesale market, EEI contends that non-RTO vertically integrated utilities have failed the market share screen using the current native load proxy when many simply do not have market power.[116] EEI concludes that such a high number of ''e positives'' for market power that have occurred using the current proxy clearly supports the Commission's proposal to move the native load proxy to the average peak load in the season.

Commission Determination

135. We adopt the NOPR proposal to change the native load proxy under the market share indicative screen from the minimum native load peak demand for the season to the average of the daily native load peak demands for the season, making the native load proxy for the market share indicative screen consistent with the native load proxy under the pivotal supplier indicative screen.

136. In this regard, we find that the market share screen should be calculated using as accurate a representation of market conditions for each season studied as possible. We find that using the current native load proxy using the minimum native load level for the season does not provide an accurate picture of the conditions throughout the season.

137. We recognize that increasing the native load proxy will have the effect of reducing the market share for traditional utilities with significant native load obligations, and therefore may result in fewer failures of the wholesale market share screen for some sellers. However, we believe that such a result is justified. We are seeking a screen that provides a reasonably accurate picture of a seller's position given market conditions across seasons, so that we can eliminate those sellers who clearly do not have market power and focus our analysis on those who might. We believe that a native load proxy based on the average of peak load conditions is more representative, and thus more accurate, than a proxy based on extreme (*i.e.*, minimum) peak load conditions. We also believe that basing the native load proxy on the average of the peaks will make the screens more accurate in eliminating sellers without market power while focusing on ones that may have market power.

138. For sellers that contend that the proposed native load proxy will result in too many false positives, we note that under the existing native load proxy, fewer than 25 companies have been the subject of section 206 investigations since the April 14 Order. For entities that fear this change in native load proxy will lead to too many ''false negatives,'' (companies with market power passing under the indicative screens), we note that intervenors can always challenge the presumption of no market power. Moreover, no intervenor in this proceeding has pointed to specific companies that have passed the screens but still have market power.

139. We reject APPA/TAPS' argument that changing the native load proxy would result in the market-based rate screens making no assessment of off-peak periods. In fact, the native load proxy we approve here is based on the average of the native load daily peaks which also include low load days. The use of the average peak demand for the native load proxy provides for an assessment of all periods, peak and off-peak seasons, because such a proxy considers peak native load of each day in each season. Combined with the pivotal supplier screen that captures the annual peak conditions, we find that the two screens adequately capture market conditions over the year.

140. We also reject APPA/TAPS' argument that consistency across the two screens defeats the purpose of having more than one screen. The screens in and of themselves are inherently different methodologies in that the pivotal supplier screen considers whether the seller's generation must run to meet peak load, whereas the market share screen looks at the seller's size relative to other sellers in the market. We are looking for an assessment of the uncommitted seasonal capacity available to sellers to compete in wholesale markets and, as stated above, find that the average of the daily peak loads in a season more accurately reflects seller's commitments.

141. APPA/TAPS suggest that if we do raise the native load deduction, we only raise it to the average minimum for the season, rather than the average native load peak demand for the season. The intent of the wholesale market share screen is to assess market conditions during the season, not only during off-peak hours. APPA/TAPS is misplaced in its assertion that our original intent was for the market share screen to focus solely on off-peak conditions. In the April 14 Order we stated that ''by using the two screens together, the Commission is able to measure market power both at peak and off-peak times.'' [117] Our statement simply recognizes that a seller with a dominant position in the market could have market power in the off-peak as well as the peak. Clearly the pivotal supplier analysis is designed to assess market power at peak times, but that does not imply that the wholesale market share screen is designed only to assess market power in the off-peak period.

142. Finally, we will not exclude weekends and holidays from the market share native load proxy. Since we adopt herein the use of an average peak demand for the native load proxy for the market share screen, the exclusion of weekends and holidays would inappropriately skew the results. Use of an average load addresses the issue of the variability between unusually high or low load days, is more objective, and easily applied. If weekends and holidays are excluded, only approximately 70 percent of total load hours would be accounted for. The

[114] *See, e.g.*, EEI at 17, PG&E at 6–7, Allegheny at 7–8, and Pinnacle at 34, both citing *Pinnacle West Capital Corp.*, 109 FERC ¶ 61,295 (2004). Several commenters disagree with the suggestion that weekends and holidays should be excluded from the native load proxy, stating that it is unsupported and, moreover, excluding these hours means that native load proxy ceases to be average. TDU Systems reply comments at 8–9, NRECA reply comments at 16–17.

[115] EEI at 24–25; *see also* Puget reply comments at 2.

[116] EEI reply comments at 24.

[117] April 14 Order at P 72.

average native load measure that includes weekends and holidays, and which we adopt, is truly an average of all load conditions.

b. Pivotal Supplier Indicative Screen

Commission Proposal

143. In the NOPR, the Commission proposed to retain the pivotal supplier screen's native load proxy at its current level of the average of the daily native load peaks during the month in which the annual peak day load occurs.[118]

Comments

144. Southern states that the pivotal supplier screen is conceptually sound; however, the manner of its current implementation reflects a significant flaw. In particular, Southern claims that the wholesale load (market size) is determined by the difference between the control area's needle peak demand and the average of the daily peaks in that peak month. Southern argues that it is not at all clear how or why this mathematical exercise (which in its opinion reflects an ''apples and oranges'' comparison) provides any meaningful measure of competitive wholesale demand during any relevant period.

145. For example, Southern continues, under some circumstances, all or a large portion of the wholesale load determined in this fashion could be the seller's own native load. Subtracting the average daily peaks in the peak month from a single needle peak to derive a ''proxy'' for competitive wholesale demand necessarily assumes that all of this difference is unsatisfied wholesale market demand that is subject to competition. Southern argues that this is not a valid assumption and the Commission has provided no reason to believe that it is. Southern therefore urges the Commission to abandon this aspect of the interim pivotal supplier analysis and instead use an estimate of actual wholesale load, rather than deriving it indirectly through an arithmetic exercise. For example, the seller's native load peak could be subtracted from the control area peak load on an ''apples to apples'' basis (for example, needle peaks, seasonal peaks, or average daily peaks) to derive, in Southern's view, a much better wholesale load proxy.[119] Southern asserts that such a reform would be relatively easy to implement and would yield much more meaningful results.[120]

146. NRECA disagrees with Southern's proposed modification to the pivotal supplier screen to use actual wholesale load, stating Southern provides no evidence that this modification would provide a more accurate estimate of the wholesale load than the current approach.[121]

Commission Determination

147. We retain the average daily peak native load as the native load proxy used in the pivotal supplier screen, as proposed in the NOPR, and we reject Southern's argument that our method of computing the native load proxy is unreasonable. Southern argues that because the wholesale demand is determined by subtracting the average daily peaks in the peak month from a single needle peak, the Commission is relying on an invalid assumption with regard to the wholesale demand during any relevant period. However, Southern's claim that our deduction of the average of the daily native load peaks from the needle peak is a ''mixing of apples and oranges'' ignores our reasoning in the April 14 Order:

> conditions in peak periods can provide significant opportunity to exercise market power. As capacity is utilized to meet demand there is less available to sell on the margin and often less competition. Only focusing on needle peaks that occur for a single hour and that are only known after the fact does not give an accurate reflection of the competitive dynamics of peak periods. As demand increases during peak periods, buyers and sellers are positioning themselves in the market with similar but incomplete information. Buyers are projecting their needs and trying to secure needed power, while sellers are negotiating to obtain the highest price for that power. With increasing demand, fewer units are available to serve anticipated peak needs and buyers bid to secure dwindling supply load increases. In addition, buyers must be prepared for the contingency that a unit will be forced out and they will need to purchase in a period of even greater scarcity.[122]

148. Further, both native load proxies provide an adequate solution to a complicated issue. Resources used to serve native load fluctuate over the course of the day and through the seasons. As the Commission stated in the April 14 Order, ''we recognize that not all generation is available all of the time to compete in wholesale markets and that some accounting for native load requirements is warranted here. However, wholesale and retail markets are not so easily separated such that a clear distinction can be made between generation serving native load and generation competing for wholesale load. Most utility generation units are not exclusively devoted to serving native load, or selling in wholesale markets.'' [123]

149. For these reasons we continue to believe that the average of the native load peaks in the peak month is a reasonable proxy for the native load deductions under this screen. Moreover, we also find that Southern's proposed method of estimating the actual wholesale load is inappropriate because it would artificially reduce the seller's share of that load. This is because Southern's methodology only deducts the seller's native load peak from the control area peak (not the native load peaks of any other sellers in the control area), leaving the seller with a disproportionately small share of the remaining market.

c. Clarification of Definition of Native Load

Commission Proposal

150. In the NOPR, the Commission expressed its belief that there has been some inconsistency in the way in which sellers have reflected native load in performing both the screens and the DPT analysis. Because the states are under various degrees of retail restructuring, the definition of native load customers has lacked precision. Accordingly, the Commission proposed to clarify that, for the horizontal market power analysis, native load can only include load attributable to native load customers as defined in § 33.3(d)(4)(i) of the Commission's regulations,[124] as it may be revised from time to time.

Comments

151. APPA/TAPS support the native load clarification, without providing additional explanation. A number of other commenters discussed the native load clarification in the context of defining retail contracts or provider of last resort (POLR) load as native load. PPL Companies request that this clarification not be adopted unless the Commission provides further clarification that an entity selling power to a retail customer under a long-term

[118] NOPR at P 44.

[119] Southern notes that this suggested calculation would still overstate the amount of wholesale load open to competition because some portion of that wholesale load would undoubtedly be covered with existing supply arrangements. It states that if it were required to net out the amount of wholesale load covered by those existing supply arrangements, a similar amount should be subtracted from the market resources deemed to be competing to serve the net wholesale load.

[120] Southern at 18–19.

[121] NRECA reply comments at 19–20.

[122] April 14 Order, 107 FERC ¶ 61,018 at P 91.

[123] *Id.* at P 67.

[124] 18 CFR 33.3(d)(4)(i) provides: Native load commitments are commitments to serve wholesale and retail power customers on whose behalf the potential supplier, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate its system to meet their reliable electricity needs.

contract is able to deduct that capacity.[125]

Commission Determination

152. We will adopt the NOPR proposal that, for the horizontal market power analysis, native load can only include load attributable to native load customers as defined in § 33.3(d)(4)(i) of our regulations. We address the comments of PPL Companies' and others below in the ''Other Native Load Concerns'' section.

d. Other Native Load Concerns

Comments

153. Some commenters suggest alterations to the definition of native load or to the circumstances when contract capacity may be deducted from total capacity. One commenter recommends that POLR load be counted as native load.[126] Sempra argues that generators should be allowed to take native load deductions for power supplied to franchised utilities that divested their generation.[127] It argues that allowing such suppliers to claim native load deductions correctly assigns these obligations to the entities that actually commit the generation resources necessary to serve native load and results in a more accurate assessment of the suppliers' remaining uncommitted capacity. It notes that such sales may be for terms of less than one year, and that under the Commission's policy such suppliers cannot deduct those commitments as long-term firm sales. Sempra further points out that franchised utilities do not need a one-year or greater commitment to take a native load deduction. It concludes that marketers and other suppliers should thus be allowed to account for the native load commitments they undertake, regardless of the term of each underlying contract.[128]

Commission Determination

154. We will not adopt suggestions that sellers receive native load deductions for all their POLR contracts or for all contracts that serve utilities that have divested their generation. Even in cases where independent power producers (IPPs) serve what used to be franchised public utilities' native load, IPPs do not serve it under the same terms as those utilities.[129] Unlike franchised public utilities, IPPs may choose to exit the market once the contracts they sell power under have expired. However, we remind IPPs that POLR contracts with a term of one year or more may be deducted from total capacity under some circumstances. As the Commission explained in the July 8 Order, ''applicants may deduct 'load following' and 'provider of last resort' contracts for terms of one year or more under certain conditions. Specifically, we will allow sellers to deduct long-term firm load following contracts to the extent that the seller has included in its total capacity a corresponding generating unit or long-term firm purchase contract that will be used to meet the obligation. The seller's contractual peak load obligation under the contract should be used as the capacity adjustment in the pivotal supplier analysis and the seasonal baseline demand levels served under the contract should be used as the adjustments in the market share analysis. The residual capacity will be considered available for sales in the wholesale spot markets and treated as uncommitted capacity.'' [130] Also, in response to PPL Companies, we note that long-term (one year or more) firm contracts that cede control may always be deducted from total capacity.

155. We will allow IPPs to deduct short term native load obligations if they can show that the power sold to the utility was used to meet native load. We agree with Sempra that allowing such suppliers to claim native load deductions correctly assigns these obligations to the entities that actually commit the generation resources necessary to serve native load and results in a more accurate assessment of the suppliers' remaining uncommitted capacity, and that such sales may be for terms of less than one year. Under our current policy such suppliers cannot deduct those commitments as long-term firm sales, whereas franchised utilities do not need a one-year or greater commitment to take a native load deduction.

6. Control and Commitment

Commission Proposal

156. The Commission noted in the NOPR that uncommitted capacity is determined by adding the total capacity of generation owned or controlled through contract and firm purchases less, among other things, long-term firm requirements sales that are specifically tied to generation owned or controlled by the seller and that assign operational control of such capacity to the buyer.[131] The Commission further stated that long-term firm load following contracts may be deducted to the extent that the seller has included in its total capacity a corresponding generating unit or long-term firm purchase that will be used to meet the obligation even if such contracts are not tied to a specific generating unit and do not convey operational control of the generation.[132]

157. Noting that contracts can confer the same rights of control of generation or transmission facilities as ownership of those facilities, the Commission stated that if a seller has control over certain capacity such that the seller can affect the ability of the capacity to reach the relevant market, then that capacity should be attributed to the seller when performing the generation market power screens. The capacity associated with contracts that confer operational control of a given facility to an entity other than the owner must be assigned to the entity exercising control over that facility, rather than to the entity that is the legal owner of the facility.[133]

158. In the NOPR, the Commission stated that in recent years some owners have outsourced to third parties pursuant to energy management agreements the day-to-day activities of running and dispatching their generating plants and/or selling output. The Commission noted that the agreement may, directly or indirectly, transfer control of the capacity. The Commission expressed concern that under such third-party agreements, there may be instances where control of capacity has changed hands, but this capacity has not been attributed to the correct seller for the purposes of the generation market power screens.[134]

159. In cases examining whether an entity is a public utility, the Commission has examined the totality of the circumstances in evaluating whether the entity effectively has control over capacity that it manages.[135] Likewise, in providing guidance regarding events that trigger a requirement to submit a notice of change in status, the Commission has

[125] PPL Companies at 14–17.

[126] Drs. Broehm and Fox-Penner at 11–12.

[127] Sempra reply comments at 4–5.

[128] PSEG Companies in their reply comments also make similar arguments about native load that are noted above in the ''Control and Commitment of Generation'' section.

[129] *See* 18 CFR 33.3(d)(4)(i) for the definition of native load.

[130] *See* July 8 Order, 108 FERC ¶ 61,026 at P 66.

[131] NOPR at P 46.

[132] *Id.*

[133] *Reporting Requirement for Changes in Status for Public Utilities with Market-Based Rate Authority,* Order No. 652, 70 F. R. 8253 (Feb. 18, 2005), FERC Stats. & Regs., Regulations Preambles 2001–2005 ¶ 31,175 at P 47, *order on reh'g,* Order No. 652–A, 111 FERC ¶ 61,413 (2005).

[134] NOPR at P 48.

[135] *D.E. Shaw Plasma Power, L.L.C.,* 102 FERC ¶ 61,265 at P 33–36 (2003) (D.E. Shaw); *R.W. Beck Plant Management, Ltd.,* 109 FERC ¶ 61,315 at P 15 (2004) (Beck).

indicated that, to determine whether control has been acquired, sellers should examine whether they can affect the ability of capacity to reach the relevant market.

160. The Commission asked in the NOPR whether, in the interest of providing greater certainty and clarity regarding the determination of control, it should make generic findings or create generic presumptions regarding what constitutes control. In particular, the Commission sought comment on whether any of the following functions should merit a finding or presumption of control and, if so, on what basis: directing plant outages, fuel procurement, plant operations, energy and capacity sales, and/or credit and liquidity decisions.[136]

161. Alternatively, rather than focusing on these discrete functions, the Commission asked if it should establish a presumption of control for any entity that has some discretion over the output of the plant(s) that it manages. The Commission asked whether such an approach would promote greater certainty. The Commission also asked, if it adopted such a presumption, how it should address instances where discretion over plant output may be shared between more than one party.[137]

162. The Commission proposed to clarify that, in the event it adopted any such presumptions, an individual seller could rebut the presumption of control on the basis of its particular facts and circumstances. In addition, the Commission proposed to clarify that an entity that controls generation from which jurisdictional power sales are made is required to have a rate on file with the Commission. If the rate authority sought is market-based rate authority, then that entity is subject to the same conditions and requirements as any other like seller.[138]

163. The intent of the Commission's proposals was to provide greater certainty and clarity as to the treatment of capacity that is subject to energy management agreements and outsourcing of functions so that the capacity is properly reported (and studied) and to make clear that any entity to which control is attributed must receive the necessary authorizations under the FPA in order to provide jurisdictional services.[139]

a. Presumption of Control

164. As an initial matter, most commenters support the Commission's desire to provide greater clarity and certainty regarding the determination of control.[140] In this regard, many commenters express concerns that attributing generation capacity to sellers that do not necessarily control that generation may result in the seller falsely appearing to have market power and ultimately result in unnecessary mitigation. Commenters also express the need for the determination of control to be consistent for both the market-based rate authorizations and the change in status filings.

165. However, most commenters also oppose the Commission's proposal to establish generic findings or generic presumptions regarding what constitutes control, arguing that such findings must be made on a case-by-case basis. Others suggest a rebuttable presumption that control lies with the owner unless specific facts indicate otherwise.

i. Fact Specific Determinations

Comments

166. Various commenters argue for a fact specific determination of control.[141] For example, Alliance Power Marketing, a supplier of energy management services, argues that a case-by-case approach provides increased certainty for generators and asset managers who relied upon Commission precedent in developing their current arrangements.[142]

167. Several commenters state that they have some sympathy with the Commission's desire to provide certainty and clarity in this area, however, they do not agree that there should be generic presumptions regarding the indicia of control. One commenter argues that details of each contract vary, depending upon parties and circumstances involved as well as on conditions in the market place, and therefore it must be reviewed and evaluated with care.[143] This commenter suggests that an individual seller should be obligated to submit its contracts to the Commission for review, and allowed to present its case on the basis of its particular facts and circumstances.

168. Similarly, APPA/TAPS believe that the Commission is correct to assign capacity to a seller for purposes of running the screens/DPT; however, they point out that generic findings or presumptions would be helpful only if the particulars of a contract aligned with the factual assumptions underlying a presumption. Otherwise, they state that a presumption could produce wrong results.[144] APPA/TAPS suggest that any arrangement that could create opportunities for sellers to coordinate their behavior with other competitors should be reported and that as part of the seller's assigning control over long-term contracts for purposes of the screens/DPT, the Commission should require a seller to submit the relevant contracts with the market-based rate application or triennial update and identify the contractual provisions that support the seller's control determinations.[145] APPA/TAPS suggest that marketing alliances or joint operating agreements can affect a seller's market position and should be considered in the determination of control.[146]

169. Powerex argues that clarity is particularly important as the new market manipulation rule makes it unlawful "to omit to state a material fact necessary in order to make the statements made, in the light of the circumstances under which they were made, not misleading." [147] In this regard, Powerex urges the development of a single principle or set of principles that need to be met to establish control over an asset. Powerex argues that the development of such principles will help take the guesswork out of compliance and provide greater certainty for the market, as compared to a laundry list of possible contract types. Powerex states that the control principle should focus on physical output as opposed to financial terms, since it is physical output that addresses the Commission's physical withholding concerns and relates to the agency's market screens.[148]

170. EEI, EPSA, and Reliant argue that the Commission should continue to look at the totality of circumstances and attach the presumption of control when an entity can affect the ability of capacity to reach the market.[149]

171. NYISO states that based on its experience in the administration of bid-based markets, what matters in the control of a plant is the ability to determine or significantly influence (a)

[136] *NOPR* at P 49.

[137] *Id.*

[138] *Id.* at P 50.

[139] *Id.*

[140] *See, e.g.,* Constellation at 18; EEI reply comments at 25; Financial Companies at 4; FirstEnergy at 5; Pinnacle at 4; Powerex at 7; SCE at 2.

[141] *See, e.g.,* Constellation at 18; Duke at 24; EPSA at 38; PPL at 9 and reply comments at 11; APPA/TAPS at 76.

[142] Alliance Power Marketing reply comments at 7.

[143] Drs. Broehm and Fox-Penner at 6–7.

[144] APPA/TAPS at 76.

[145] *Id.* APPA/TAPS further note that confidentiality concerns can be addressed with appropriate protective orders.

[146] APPA/TAPS at 77 and 89.

[147] Powerex at 7 (quoting 18 CFR 1c.2(a)(2)).

[148] Powerex at 8.

[149] *See, e.g.,* EEI at 19; EPSA at 37–38; Reliant at 5–6; SoCal Edison at 9.

The levels of the bids from the plant, and (b) the level of output from the plant. Accordingly, the Commission should focus directly on these critical facts, rather than creating presumptions based on indirect indicia of an ability to control these key competitive parameters. NYISO claims that plant engineering or technical operations may be outsourced without conferring an ability to control price or output, so that the outsourcing is not of particular competitive significance. If, however, an entity could determine or significantly influence bids or output, then it would be reasonable for the Commission to place a burden on that entity to demonstrate that it is not in a position to benefit from a possible exercise of market power. NYISO claims that if more than one party is in a position to exercise control over bids or output, then both such parties should have the burden of rebutting this presumption. NASUCA concurs.[150] Because of the fact-specific nature of these issues, the NYISO endorses the Commission's proposal to allow individual sellers to rebut the presumption on the basis of their particular facts and circumstances.[151]

172. Westar argues determinations of control over generating plants are essential elements of the negotiated risk sharing arrangement in virtually every energy management contract and that the Commission should not change its precedent absent clear evidence of market uncertainty or a finding that the established guidelines are inappropriate.[152]

173. Southern suggests that the approach taken in Order No. 652, where the Commission provided an illustrative list of contracts and arrangements that involve changes of control, is reasonable.[153]

Commission Determination

174. As discussed in the sections that follow, the Commission concludes that the determination of control is appropriately based on a review of the totality of circumstances on a fact-specific basis. No single factor or factors necessarily results in control. The electric industry remains a dynamic, developing industry, and no bright-line standard will encompass all relevant factors and possibilities that may occur now or in the future. If a seller has control over certain capacity such that the seller can affect the ability of the capacity to reach the relevant market, then that capacity should be attributed to the seller when performing the generation market power screens.[154]

175. Though we note the widespread support among commenters for the Commission's effort to provide greater clarity and certainty regarding the determination of control, there are differing points of view as to what circumstances or combination of circumstances convey control. These circumstances vary depending on the attributes of the contract, the market and the market participants. Thus, we conclude that it would be inappropriate to make a generic finding or generic presumption of control, but rather that it is appropriate to continue making our determinations of control on a fact-specific basis.

176. We agree with commenters such as Powerex and Westar that the Commission should rely on a set of principles or guidelines to determine what constitutes control. This has been our historical approach and we find no compelling reason to modify our approach at this time. Accordingly, as suggested by EEI, EPSA and others, we will consider the totality of circumstances and attach the presumption of control when an entity can affect the ability of capacity to reach the market. Our guiding principle is that an entity controls the facilities when it controls the decision-making over sales of electric energy, including discretion as to how and when power generated by these facilities will be sold.[155]

177. With regard to suggestions that we require all relevant contracts to be filed for review and determination by the Commission as to which entity controls a particular asset (*e.g.*, with an initial application, updated market power analysis, or change in status filing), we will not adopt this suggestion. Under section 205 of the FPA, the Commission may require any contracts that affect or relate to jurisdictional rates or services to be filed. However, the Commission uses a rule of reason with respect to the scope of contracts that must be filed and does not require as a matter of routine that all such contracts be submitted to the Commission for review. Our historical practice has been to place on the filing party the burden of determining which entity controls an asset. As discussed below, we will require a seller to make an affirmative statement as to whether a contractual arrangement transfers control and to identify the party or parties it believes controls the generation facility. Nevertheless, the Commission retains the right at the Commission's discretion to request the seller to submit a copy of the underlying agreement(s) and any relevant supporting documentation.

ii. Rebuttable Presumption Regarding Ownership

Comments

178. MidAmerican argues that the Commission should adopt a presumption of control based on physical ownership of the generation (as adjusted for long-term sales or purchase power agreements). MidAmerican states that it is physical ownership that typically determines which entity controls the output of the generation and determines its ability to reach relevant markets. While many entities may have partial control over a unit's output, it is the owner that is most likely to affect market power.[156]

179. Morgan Stanley states that as a general rule, when assessing market power, the Commission should specifically adopt a rebuttable presumption that the entity that owns [157] the generation asset controls the generation capacity.[158] This presumption would shift if the asset owner relinquishes to a third-party the final decision-making authority over whether a unit runs (*i.e.*, if the third-

[150] NASUCA reply comments at 15 (quoting NYISO at 6).

[151] NYISO at 5–6.

[152] *See, e.g.*, Westar at 27–28.

[153] Southern at 23 (citing Order No. 652, FERC Stats. & Regs. Regulations Preambles 2001–2005 ¶ 31,175 at P 83.

[154] NOPR at P 47–48 (citing July 8 Order, 108 FERC ¶ 61,026 at P 65.)

[155] Order No. 652, FERC Stats. & Regs. Regulations Preambles 2001–2005 ¶ 31,175 at P 18.

[156] MidAmerican at 4 and 6–7.

[157] Morgan Stanley states that consistent with Commission precedent, the generation owner would not include entities that have a ''passive'' ownership interest where, due to the nature of the interest, the interest holder does not have the right or ability to direct, manage, or control the day-to-day operations of jurisdictional facilities. Citing *D.E. Shaw*, 102 FERC ¶ 61,265, at 61,823 (2003) (noting that passive owners may possess certain consent or veto rights over fundamental business decisions in order to preserve their financial investment, including, but not limited to, the right to grant or withhold consent regarding: (1) Material amendments to an LLC agreement under certain, specified circumstances; (2) issuance of new interests senior to the then-existing member interests in an LLC entity; (3) adoption of a new LLC agreement (or other operative or constituent documents) in connection with mergers, consolidations, combinations, or conversions in certain instances; (4) appointment of a liquidator (but only if the managing member of the LLC does not appoint one); and (5) assignment of investment advisory contracts under certain circumstances); *GridFlorida LLC,* 94 FERC ¶ 61,363, at 62,332 (2001).

[158] Morgan Stanley would define final control over physical output as resting with the market participant that, under normal operating conditions, can override all other entities on the decision of whether to dispatch the generation unit or that can otherwise hold an entity accountable for a dispatch decision. It submits that such authority typically rests with the generation owner. Morgan Stanley at 4.

party can trump the asset owner's dispatch instruction, then the third-party has control over whether the capacity reaches the market). Morgan Stanley states that such final decision-making authority would include authority to schedule outages.[159]

180. FirstEnergy proposes that where a generation owner is a public utility under Part II of the FPA, the Commission should adopt a rebuttable presumption that such owner controls all of the generating capacity that it owns.[160] FirstEnergy asserts that even where another entity is responsible for day-to-day operation of a generating unit, the generation owner generally will retain managerial discretion over the operation of the unit and over the sale of power from that unit into the market.[161]

181. A number of commenters argue that jointly-owned plants should be assigned based on percentage of ownership.[162] For example, Pinnacle states that, in the Southwest region, the joint ownership of base-load generating plants is the norm, and there is typically one party that has operational control over the facility. However, if the Commission refines the criteria for assigning generation to an entity based on factors such as directing plant outages, fuel procurement, and plant operations (or similar factors), there is concern that jointly-owned generation may be attributed in whole to each of the owners if there is joint decision-making on such factors (*e.g.*, if such decisions are made through a consortium of utilities forming a plant's joint operating committee) and result in unintentional double counting. Pinnacle also raises a concern that where joint plant owners appoint one of the joint owners to operate the plant, the entire plant will be attributed to the operator, rather than being attributed to each of the joint owners in shares. According to Pinnacle, the Final Rule should clarify that capacity of jointly-owned plants operated by one of the owners will be assigned to each joint owner based on its percentage interest.[163] Pinnacle states that the current rules under the interim screens with regard to assigning generating capacity to an entity appear to be workable.[164]

182. Many other commenters raise concerns about double counting in cases of shared control.[165] For example, with regard to shared facilities, FirstEnergy states that control of the plant should be attributed to the entity that is deemed to own the energy supplied from the plant. FirstEnergy offers that, if circumstances arise in which discretion over plant output is shared among more than one party, the Commission should permit the affected parties to resolve between themselves the entity to which capacity available in the unit will be attributed. FirstEnergy concludes that if the Commission adopts a regional approach to updated market power analyses, the Commission will be able to monitor those circumstances in which specified generation capacity is attributed to the wrong market participant.[166]

Commission Determination

183. With regard to the suggestion that we adopt a rebuttable presumption that the owner of the facility controls the facility, our historical approach has been that the owner of a facility is presumed to have control of the facility unless such control has been transferred to another party by virtue of a contractual agreement. We will adopt that approach. Accordingly, while we do not specifically adopt a rebuttable presumption that the owners control the facility, we will continue our practice of assigning control to the owner absent a contractual agreement transferring such control.

184. We note that the Commission has developed precedent regarding the contractual arrangements that can transfer control. In these cases, the Commission has stated that control refers to arrangements, contractual or otherwise, that confer control of generation or transmission facilities just as effectively as they could through ownership.[167] The capacity associated with contracts that confer operational control to an entity other than the owner thus must be assigned to the entity exercising control over that facility, rather than to the entity that is the legal owner of the facility, when performing the generation market power screens.[168]

185. With regard to FirstEnergy's suggestion that the affected parties make a determination regarding the entity to whom capacity available in the generating unit will be attributed in order to avoid any unwarranted double counting in the attribution of control,[169] the Commission agrees that this is a constructive and appropriate approach. However, although we wish to avoid double counting as a general matter, the Commission will not rule out the possibility of double counting in circumstances where it is unclear what entity has control. For example, if different parties could control dispatch decisions under various circumstances, to err on the conservative side, the Commission may attribute generation to more than one seller for the purposes of the horizontal analysis.

186. To determine whether there are contracts transferring control to a seller seeking market-based rate authority, similar to the requirements for change in status filings,[170] the Commission will

[159] *See also* Financial Companies at 6.

[160] FirstEnergy similarly argues that there should be a rebuttable presumption that generation capacity purchased by an electric utility from a Qualified Facility (''QF'') as a result of a mandatory power purchase requirement established pursuant to the Public Utility Regulatory Policies Act (PURPA), 16 U.S.C. 824a–3(a), will be attributed to the seller rather than the purchaser. FirstEnergy argues that in many cases, the purchaser has little, if any, discretion over the dispatch of such units or the price at which energy is purchased.

[161] In its reply comments, PPL disagrees stating that, in assessing the entity that should be deemed to control capacity, whether assessing a contract to sell capacity or an asset management contract, the Commission should ask which party can benefit from an exercise of market power with regard to the supply at issue. PPL asserts that the flaw in FirstEnergy's proposal is that when a firm obligation to sell power is in effect, the seller cannot benefit from exercising market power with regard to the MWs sold pursuant to that firm obligation. Likewise, a buyer that can count on delivery of firm power is the ultimate decision-maker as to its resale. The seller will have to buy replacement power (at the prevailing market rate) if its expected source is not available, and therefore cannot benefit from withholding that amount of power. Thus such an approach would overstate one counter party's controlled capacity and understate the other's. PPL reply comments at 11–13.

[162] *See, e.g.*, Duke at 25.

[163] Pinnacle at 4–5. *See also* MidAmerican at 6–7.

[164] EEI agrees that in such a situation, if both owners have input on how and where the capacity is sold, then the asset should be allocated based on ownership percentages. EEI at 20.

[165] *See, e.g.*, Alliance Power Marketing reply comments at 8–9; Constellation at 6; MidAmerican at 6; PG&E at 8.

[166] FirstEnergy at 7–8.

[167] *Citizens Power and Light Corp.*, 48 FERC ¶ 61,210 at 61,777 (1989). *See also Bechtel Power Corp.*, 60 FERC ¶ 61,156 (1992) (finding that an entity that was contractually engaged to provide operation and maintenance services was not an ''operator'' of jurisdictional facilities because the entity did not ''operate'' the facilities at issue but rather, in essence, was functioning merely as the owner's agent with respect to the operation of the jurisdictional facilities); *D.E. Shaw*, 102 FERC ¶ 61,265 at P 33–36 (finding that a power marketer's ''investment adviser'' affiliate was a public utility where it had sole discretion to determine the trades to be entered into by the power marketer, as well as the power to execute the contracts, and therefore operated jurisdictional facilities rather than acted as merely an agent of the owner); *R.W. Beck*, 109 FERC ¶ 61,315 at P 15 (finding R.W. Beck Plant Management, Ltd. (Beck) was a public utility subject to the FPA in connection with its activities as manager of public utility Central Mississippi Generating Company, LLC because Beck effectively governed the physical operation of certain jurisdictional transmission and interconnection facilities and served as the decision-maker in determining sales of wholesale power).

[168] NOPR at P 47–48 (citing July 8 Order, 108 FERC ¶ 61,026 at P 65).

[169] FirstEnergy at 7.

[170] *See Calpine Energy Services, L.P.*, 113 FERC ¶ 61,158 at P 13 (2005) (sellers making a change in status filing to report an energy management agreement are required to make an affirmative statement in their filing as to whether the agreement

require sellers when filing an application for market-based rate authority or an updated market power analysis, to make an affirmative statement as to whether any contractual arrangements result in the transfer of control of any assets, including whether the seller is conferring control to another entity or obtaining control of another entity's assets. Moreover, in addition to requiring such affirmative statements as to whether any contractual arrangements result in the transfer of control of any assets,[171] the Commission will require sellers, when filing an application for market-based rates, an updated market power analysis, or a required change in status report with regard to generation, to specify the party or parties they believe has control of the generation facility and to what extent each party holds control.

187. We understand that affected parties may hold differing views as to the extent to which control is held by the parties. Accordingly, we also will require that a seller making such an affirmative statement seek a ''letter of concurrence'' from other affected parties identifying the degree to which each party controls a facility and submit these letters with its filing. Absent agreement between the parties involved, or where the Commission has additional concerns despite such agreement, the Commission will request additional information which may include, but not be limited to, any applicable contract so that we can make a determination as to which seller or sellers have control.

188. With regard to Pinnacle's concern regarding joint plant owners appointing one of the joint owners to operate the plant, we reserve judgment as a general matter. However, we understand that there may be situations where a jointly-owned generation facility is operated by one of the joint-owners for the benefit of and on behalf of all of the joint-owners. Under these circumstances, it may be reasonable to allocate capacity based on ownership percentages. Such a determination should be made on a case-specific basis.

189. We remind sellers that in performing the horizontal market power analysis all capacity owned or controlled by the seller must be accounted for. In this regard, we expect that sellers, in performing such market power analyses, will clearly identify all assets for which they have control, or relinquished control, through contract.

iii. Energy Management Agreements

Comments

190. Most commenters state that energy management agreements and the functions listed in the NOPR (directing plant outages, fuel procurement, plant operations, energy and capacity sales, and/or credit and liquidity decisions) should not be presumed to convey control. Financial Companies state that a generic presumption of control by energy managers will ''chill a seller's willingness to provide energy management services.'' [172] Others suggest that the Commission should not adopt such a presumption and, in the alternative, should consider the specific aspects of an agreement. Additionally, some commenters request clarification on contract terms that are widely used in energy management agreements and may or may not convey control.

191. Sempra and financial entities argue that the Commission should not adopt a presumption that energy management agreements confer control over generating capacity.[173] They state that energy management and comparable agreements do not convey unlimited discretion and should not shift the presumption of control away from the entity that has final authority to dispatch the physical output of the plant.

192. Constellation agrees that the Commission should focus on whether an energy manager may make decisions about physical operation without final authority from a plant owner.[174]

193. Westar expresses concerns that the NOPR's invitation to consider ultimate control to reside with any entity that has some discretion over the output of a plant would invite confusion and undercut the Commission's declared objective to provide greater certainty and clarity in this area.[175] Alliance Power Marketing also expresses concern that a presumption that some discretion constitutes control will discourage innovation in the market, particularly with regard to option contracts and third-party arrangements.[176]

194. Alliance Power Marketing differentiates between asset/energy managers acting purely as agents and those that do not meet the legal definition of agents, suggesting that a market facilitator meeting the criteria of an agent should be exempt from attribution of control. The agent criteria identified by Alliance Power Marketing are: (1) The entity holds legal indicia of an agent's role; (2) the entity is neither a market participant nor an affiliate of a market participant; (3) the entity has limited, if any, financial stake in power market outcomes; and (4) the entity is subject to supervision or control in its activities on behalf of its principals.[177] Alliance Power Marketing submits that agents do not control generation if they are acting on behalf of their clients, do not assume the risk of transactions, and never take title to power. Constellation notes that the Commission has previously recognized that an agent who is acting subject to the direction of the owner should be not found to have control of a facility.[178]

195. Financial Companies disagree with Alliance Power Marketing's differentiation. They caution the Commission about imposing overly restrictive limitations on which entities qualify as agents or independent contractors and recommend that the Commission reject Alliance Power Marketing's proposal and suggest instead that ultimate decision-making authority is most relevant whether or not an agent is or is not a market participant.[179]

196. In contrast, NASUCA submits that the Commission should presume that energy management agreements convey control when energy managers can control generation output or the price or quantity of service offered.[180] Even more specifically, NASUCA recommends that the Commission reject formulations that would cloak market power of energy managers who control or affect electricity pricing, or the pricing of critical cost components such as fuel. Instead the Commission should adopt a rule that at a minimum encompasses the exercise of control over prices, bids, or output, including the ability to affect the cost of fuel and other inputs to generation.[181]

Commission Determination

197. After careful consideration of the comments, the Commission will not adopt a presumption of control regarding energy management agreements or the functions outlined in

at issue transfers control of any assets and whether the agreement results in any material effect on the conditions that the Commission relied upon in the grant of their market-based rate authority).

[171] Such a statement should include contracts that transfer control to another party as well as contracts that transfer control to the seller.

[172] Financial Companies at 9.

[173] Sempra at 12–13; Morgan Stanley at 5–6; Financial Companies at 7–8 and reply comments at 3–5.

[174] Constellation at 18.

[175] Westar at 28.

[176] Alliance Power Marketing reply comments at 8–9.

[177] *Id.* at 10–11.

[178] Constellation at 20 (citing *Bechtel Power Corp.,* 60 FERC ¶ 61,156 at 61,572 (1992)).

[179] Financial Companies reply comments at 3–4.

[180] NASUCA reply comments at 13 (*citing* NYISO at 6).

[181] *Id.* at 15.

the NOPR.[182] We agree with commenters that energy management and comparable agreements do not necessarily convey unlimited discretion and control away from the entity that owns the plant. In this regard, as noted above, it is the totality of the circumstances that will determine which entity controls a specific asset.

198. Further, the Commission will not adopt a presumption of control in the case of shared discretion over the output and physical operation of a plant. The Commission is aware that varying degrees of discretion may be shared in some cases, and believes that the determination of control in these cases is best addressed on a fact-specific basis. As noted by Sempra, there may always be an element of discretion associated with the implementation of instructions or guidelines included in energy management agreements.[183]

199. With regard to Alliance Power Marketing's differentiation between asset/energy managers acting purely as agents and those that do not meet the legal definition of agents, and suggestion that ''a market facilitator meeting the criteria of an agent should be exempt from attribution of control,'' we find this differentiation in and of itself not determinative. Instead, consistent with our conclusion that the determination of control is appropriately based on a review of the totality of the circumstances on a fact-specific basis such that no single factor or factors necessarily results in control, it is the combination of the rights conveyed that determine control, not whether an entity considers itself to be an agent and not a market participant.

iv. Specific Functions and Contract Terms

Comments

200. With regard to specific functions and specific contract terms, many commenters do not believe that functions such as directing plant outages, fuel procurement, plant operations, energy and capacity sales, and credit and liquidity merit a presumption of control.

201. NYISO and FirstEnergy both suggest that the functions listed in the NOPR may be outsourced without conveying ultimate control. According to EEI, the list of functions described in the NOPR would not provide greater guidance.[184] Rather, EEI believes a focus on the ability to withhold will be more effective than establishing presumptions based on the functions described in the NOPR. In particular, EEI argues that establishing presumptions for these individual functions would be difficult, because often it would be a combination of various functions that would result in the ability to affect bringing the capacity to market.[185]

202. Duke believes that the Commission should avoid simplistic presumptions as to what constitutes control over resources for market power purposes and how and when specific generation should be imputed to market participants for purposes of the screen analysis. Duke argues that in a market power context, such determinations should be fact-driven and based on a pragmatic assessment of which party has the ability to withhold a specific amount of capacity from the market. For example, the Commission should not automatically impute control over capacity based solely on contract language that appears to convey some element of discretion over unit operation to a particular party, notwithstanding the absence of any real world ability for that entity to withhold that capacity from the market. Duke states that the Commission should recognize that the ability to economically or physically withhold output from the market rests with the party that makes the final determination of whether generation (energy and/or capacity) will be offered into the market. Even a purchaser with dispatch rights may not have the ability to withhold supply, if the capacity owner has the right to schedule energy when the purchaser chooses not to do so. Similarly, a party with a contractual right to capacity (as opposed to energy), even with a call option for energy priced at market, does not have operational control over energy. Duke states that any contract in which rights to the energy ultimately revert to the owner/operator or for which energy is available only at a market price leaves control in the hands of the owner/operator. According to Duke, there should not be a blanket presumption that certain types of commercial arrangements or contractual language imply control in all instances.[186]

203. PG&E argues that any presumptions about control over generation should be based on whether a seller controls the dispatch of energy (*i.e.*, can affect the ability of the capacity to reach the relevant market). This general presumption should cover all types of transactions and business arrangements, rather than trying to address every possible function. Such an approach will be more effective than establishing presumptions based on individual functions, as various factors may intersect or combine to provide this control. Relevant factors include authority over the use or provision of fuel to the plant.[187]

204. PPL expresses concern that any arrangement in which a gas supplier could receive the output of a gas-fired generator as payment for the gas it supplies to the generator, if it is the only supplier to that generator, may convey control. PG&E appears to agree, stating that authority over the use or provision of fuel to the plant is a relevant factor with regard to control.[188]

205. EEI also appears to agree that fuel ownership may result in a change in control of plant output when, in the context of what triggers a change in status filing, it states: ''The Commission should continue the current policy that changes in the ownership of fuel supplies in and of themselves need not be reported. Only if the change in ownership of inputs results in a change of control of the output of the plant should a change in status filing be required. If a public utility acquires fuel supplies, there is no need to notify the Commission, unless the business structure, like a tolling agreement, actually results in discretion over the plant output.'' [189]

206. Sempra states that the Commission has generally treated energy management agreements as tolling agreements and requests that the Commission acknowledge the differences between the two.[190] APPA/TAPS state that particularly under tolling arrangements, while the supplier of fuel may not be operating the plant, it controls the plants' production of energy for sale, thus affecting market outcomes.[191] Constellation argues that plant operations and sales of output are functions that may convey control, but notes that the variety of case-specific facts limits the benefit of a blanket presumption of control.

207. Commenters also request that the Commission provide guidance regarding other contract types and terminology

[182] NOPR at P 49.

[183] Sempra at 13.

[184] EEI reply comments at 25.

[185] EEI at 22.

[186] Duke at 24–25.

[187] PG&E at 7.

[188] *Id.*

[189] EEI at 21.

[190] Sempra at 11–12. According to Sempra, under energy management agreements, energy managers typically sell power according to instructions or guidelines provided by the owner, and the energy manager is compensated on a fee-basis. Sempra states that in the case of tolling agreements, the tolling party generally has complete discretion over sales of output and assumes risk of sales transactions with the owner typically receiving a flat compensation and retaining authority over when to operate the facility.

[191] APPA/TAPS at 90.

such as call option contracts (with liquidated damages), contracts that allow variance in volume or delivery point, QF contracts, RMR contracts, capacity contracts, and load obligations.[192]

208. Finally, EEI seeks clarification that energy only contracts over 100 MW for a term greater than one year that do not include rights to specific capacity are one type of contract that does not transfer control.

Commission Determination

209. In Order No. 652, the Commission provided a non-exclusive, illustrative list of contractual arrangements that are subject to the change in status filing requirement. The list includes agreements that relate to ''operation (including scheduling and dispatch), maintenance, fuel supply, risk management, and marketing [of plant output]. These types of arrangements have in some cases also been referred to as energy management agreements, asset management agreements, tolling agreements, and scheduling and dispatching agreements.'' [193] The Commission clarifies that the illustrative list included in Order No. 652 provides guidance with regard to new applications for market-based rate authority and updated market power analyses as well as to change in status filings.

210. With respect to requests for clarification of whether certain contractual arrangements transfer control (such as call option contracts; liquidated damages contracts; contracts that allow variance in volume, source, or delivery point; QF contracts; RMR contracts; capacity contracts; and load obligations), for the reasons stated above, the Commission declines to address particular contractual terminology in isolation. The label placed on a specific contract does not determine whether it conveys control. Such determination necessarily must be made on a fact-specific basis.

211. Similarly, with regard to EEI's request for clarification that energy-only contracts over 100 MW for a term greater than one year that do not include rights to specific capacity are one type of contract that does not transfer control, for the reasons stated above, the Commission declines to address such a specific contractual arrangement generically.

b. Requirement for Sellers To Have a Rate on File

Comments

212. Alliance Power Marketing questions the Commission's proposal to clarify that any entity that controls generation from which jurisdictional sales are made is required to have a rate on file. Alliance Power Marketing believes that this proposal appears more akin to an inquiry than a Proposed Rulemaking.[194] Pinnacle requests clarification as to whether a non-jurisdictional entity is required to have a rate on file if that entity is the operator of a facility jointly-owned by jurisdictional and non-jurisdictional entities.[195]

Commission Determination

213. With regard to comments concerning the Commission's statement in the NOPR as to the need for an entity that controls generation from which jurisdictional power sales are made to have a rate on file, the Commission is reiterating, not modifying, the existing obligation to make rate filings. Under section 205 of the FPA,

> every public utility shall file with the Commission * * * schedules showing all rates and charges for any * * * sale subject to the jurisdiction of the Commission, and the classifications, practices, and regulations affecting such rates and charges, together with all contracts which in any manner affect or relate to such rates, charges, classifications, and services.[196]

Part II of the FPA defines a public utility as ''any person who owns or operates facilities subject to the jurisdiction of the Commission.'' [197] Any entity not otherwise exempted from the Commission's regulations that owns or operates jurisdictional facilities from which jurisdictional power sales are made is a public utility required to have a rate on file with the Commission, unless the Commission has determined that such an entity does not in fact have ''control'' over the jurisdictional facilities sufficient to deem it a public utility (for example, if its ownership is passive, or its operation of facilities is as an agent subject to the control of the owner of the facilities). For any entity that is a public utility, if its rate authority is market-based, then it is subject to the conditions of authorization by the Commission (including the requirement to demonstrate lack of generation market power by the submission of market screens as spelled out in the horizontal market power section of this Final Rule). If an entity is a public utility and making jurisdictional sales without having a rate on file, those sales may be subject to refund, and the entity may be subject to a civil penalty.[198]

214. In response to Pinnacle, we clarify that if an entity has control of a jurisdictional facility and that entity is making jurisdictional sales, it would be a public utility subject to the jurisdiction of the Commission and would be required to have a rate on file with the Commission. However, if an entity is specifically exempted from the Commission's regulation pursuant to FPA section 201(f), it would not be considered a public utility under the FPA and, accordingly, would not be required to have a rate on file.

7. Relevant Geographic Market

a. Default Relevant Geographic Market

Commission Proposal

215. In the NOPR, the Commission proposed to continue to use its historical approach with regard to the relevant geographic market. The Commission stated that the default relevant geographic market is the control area where the generation owned or controlled by the seller is physically located and each of the control areas directly interconnected to that control area (with the exception of a generator interconnecting to a non-affiliate owned or controlled transmission system, in which case the relevant market is only the control area in which the seller is located). The Commission also proposed to continue to designate RTOs/ISOs with sufficient market structure and a single energy market in which a seller is located and is a member as the default relevant geographic market. In such circumstances the Commission would not require sellers to consider the first-tier markets to such RTOs/ISOs as being part of the default relevant geographic markets. In addition, the Commission noted in the NOPR that its experience with corporate mergers and acquisitions indicates that the same RTOs/ISOs that the Commission has identified as meeting the criteria for being considered a single market for purposes of performing the generation market power screens have, at times, been divided into smaller submarkets for study purposes

---

[192] *See, e.g.*, EEI reply comments at 25; EPSA at 38; Financial Companies reply comments at 7; FirstEnergy at 6; Reliant at 5; Duke at 25; PG&E at 7–8; PowerEx at 9–13; PPL at 13; PPL reply comments at 13; PSEG at 13 and 18; Sempra reply comments at 4; SoCal Edison at 10; Southern Company at 23.

[193] Order No. 652, FERC Stats. & Regs. Regulations Preamles 2001–2005 ¶ 31,175 at P 83.

[194] Alliance Power Marketing at 16.

[195] Pinnacle at 5.

[196] 16 U.S.C. 824d(c).

[197] 16 U.S.C. 824(e).

[198] *Vermont Electric Cooperative, Inc.*, 108 FERC ¶ 61,223 (2004), *order on reh'g*, 110 FERC ¶ 61,232 (2005).

because frequently binding transmission constraints prevent some potential suppliers from selling into the destination market. Therefore, the Commission sought comment on its approach under the market-based rate program of considering the entire geographic region under control of the RTO/ISO, with a sufficient market structure and a single energy market, as the default relevant market. We asked whether the Commission should continue its approach of considering the entire geographic region as the default market for purposes of the indicative screens but consider RTO/ISO submarkets for purposes of the DPT.

Comments

216. With regard to the RTO/ISO market, several commenters state that, based on all the protections associated with structured RTO/ISO markets with Commission-approved market monitoring and mitigation, the Commission should continue its current approach of allowing the entire geographic region of an RTO/ISO to be the default relevant market for the horizontal market power analysis.[199] They state that retention of this standard will simplify preparation of market power analyses by sellers within qualified RTOs.

217. Several commenters as well urge the Commission not to consider RTO or ISO submarkets. Sempra states that it recognizes that RTOs are at times divided into submarkets, such as for purposes relating to corporate merger and acquisition analyses, but it submits that the Commission should not consider RTO or ISO submarkets when conducting a market power analysis. Sempra states that the use of submarkets will result in uncertainty, confusion, and increased litigation as to the geographic boundaries of the ''right'' submarket that should be analyzed. According to Sempra, sellers that operate in RTO and ISO markets currently know with certainty the relevant geographic market for purposes of regulatory obligations such as reporting relevant changes in status, and the use of submarkets will eliminate that certainty and will open the door to competing definitions of submarkets. Sempra states that the existence of internal transmission constraints does not justify breaking up RTOs and ISOs into submarkets for purposes of the Commission's market power analysis. Sempra states that notably, only RTOs and ISOs with sufficient market structure and a single energy market can be used as default geographic markets. These attributes allow RTOs, ISOs, and their members to adopt mechanisms, including local markets or mitigation, that address potential concerns about local market power resulting from transmission constraints.[200]

218. Similarly, EPSA, PG&E, PPL, ISO–NE, CAISO and NYISO support use of the entire RTO/ISO as the relevant geographic market where the RTOs/ISOs operate a single centralized market and generally where there are measures for monitoring and oversight.[201]

219. In addition, EPSA offers that changes to the size of markets can be addressed on a case-by-case basis by sellers or when an intervenor presents specific evidence supporting reduction of the relevant geographic market.[202] PG&E states that in the case of a single control area like CAISO, there is little rationale or basis to determine how to subdivide a control area. Where there may be intermittent congestion within certain areas, the control area as a whole has regional planning and monitoring, avoiding the need to subdivide. In addition, the empirical fact that most sellers make no effort to justify an alternate geographic market—whether larger or smaller—supports the control area as the appropriate measure.[203]

220. PPL states that if the Commission were to impose stringent market power tests based upon temporary transmission limitations beyond generators' control (*e.g.*, infrequent intra-control area transmission system limitations), the Commission could make worse an already tenuous financial situation for existing generators in such areas and continue to deter new generation investment. Defining a geographic market smaller than a control area may lead to high failure rates of the screens. PPL states that associated loss of market-based rate authority (if that is the remedy imposed by the Commission) could precipitate economic retirements of those needed generators.

221. Finally, Ameren suggests that, for purposes of the DPT, the relevant geographic market should be the applicable RTO/ISO footprint, just as it is for purposes of the indicative screens, unless the Commission already has found the existence of a submarket in the relevant portion of the RTO/ISO. In such cases, the Commission should give due consideration to any existing Commission-approved market monitoring and mitigation regime already in place within the RTO/ISO that provides for mitigation of the submarket. If the relevant RTO/ISO does not have in place a mitigation program for an identified submarket, the Commission may then consider appropriate submarket-specific mitigation in connection with granting market-based rate authorization.

222. On the other side of the issue, several commenters urge the Commission to consider internal transmission constraints and possible submarkets within RTOs/ISOs. The California Board proposes that the Commission permit RTOs to identify submarkets within their control area, as needed, to help determine possible local market power. The California Board states that if the Commission develops or approves criteria which sellers may use to expand their geographic market, then the same criteria must be applicable in RTOs to limit the size of a geographic market. The New Jersey Board states that intervenors should be allowed to present evidence that the relevant geographic market is smaller (or larger) than the default RTO/ISO market and states that evidence of binding transmission constraints is relevant when examining horizontal market power.[204]

223. State AGs and Advocates state that almost any large default geographic market will have many transmission-constrained areas (load pockets) within it and that the Commission must require applicants for market-based rate authority to do a proper analysis of the degree of market power that is likely to be exercised by all sellers, including the applicants, in all relevant load pockets or transmission-constrained regions or subregions in which the sellers control generation capacity. They state that all load pockets must be considered as appropriate geographic markets whenever they exist.

224. APPA/TAPS state that the presumption of the RTO footprint as the default geographic market must be truly rebuttable, including rebuttals based upon evidence that the RTO itself treats an area as a separate market.[205] APPA/TAPS state that in practice, however, the presumption appears to be irrebuttable. They argue that if known load pockets such as WUMS (or, for example, the Delmarva Peninsula, Southwest Connecticut, or the City of

[199] Wisconsin Electric at 5–7, FirstEnergy at 8–9, PG&E at 8–9, Xcel at 13–14, and Allegheny Energy Companies at 4–6. In addition, Ameren states that the Commission also should consider expanding the default geographic region beyond the footprint of a single RTO/ISO where contiguous RTOs/ISOs have a common market (Amerem at 4–5).

[200] Sempra reply comments at 1–3.

[201] EPSA at 11–12, PG&E at 8–9, and NYISO at 1–2.

[202] EPSA at 11–12.

[203] PG&E at 8–9.

[204] New Jersey Board at 3–4.

[205] APPA/TAPS at 56–63.

San Francisco, among others) do not rebut the geographic market presumption, the rebuttable presumption effectively becomes irrebuttable. APPA/TAPS recommend that in advance of each region's market-based rate review, RTOs should provide market participants with transmission studies that reveal where binding transmission constraints arise so that those data can be used in addressing the proper relevant geographic market. In addition, APPA/TAPS state that in the § 203 context, the Commission has correctly found that transmission constraints lead to distinct geographic markets, at least when those constraints are binding. They submit that no reasonable basis exists to distinguish between the competitive analyses used to establish relevant geographic markets in the section 203 and the section 205 contexts.[206]

225. In response to APPA/TAPS, EPSA states that in cases where the Commission denied a seller's argument to change its relevant geographic market, the Commission carefully considered the positions of parties advocating a different market and simply found their arguments insufficient to warrant a modification to the market definition.[207] EPSA states that it cannot be said that a presumption is irrebuttable simply because the Commission has, to date, deferred to RTO/ISO mitigation mechanisms to this point.

226. With regard to non-RTO areas, APPA/TAPS states that while the control area provides a reasonable starting point, the Commission's obligation to base its market-based rate decision on ''empirical proof'' requires reliance on specific facts that demonstrate whether the relevant geographic market should be the control area, or a smaller or larger area. APPA/TAPS further state that, for non-RTO areas, the seller should affirmatively address whether the geographic market should default to the control area or whether a smaller or larger area is appropriate, and support that result with evidence. They add that intervenors should also be allowed to introduce evidence regarding the question.[208]

227. With regard to both RTO/ISO and non-RTO areas, several other commenters urge the Commission to consider changing its existing policy on the default geographic market. State AGs and Advocates state that the best policy would be to have no ''default'' market criteria, but to have each applicant for market-based rates determine on an analytical basis what market area makes the most sense for its circumstances based on the actual transmission constraints that it faces.[209] NRECA states that using individual control areas or RTOs as the default market for evaluating a transmission provider's market power fails to account for the binding transmission constraints and load pockets that have developed within those markets.[210]

228. Morgan Stanley states that it supports the Commission's practice of relying on control areas and RTO/ISO regions when assessing market power as the default markets, but believes the Commission may be missing instances of market power by failing to also review known events that can create narrower or broader markets. For example, Morgan Stanley states that the Commission acknowledges that binding transmission constraints and the existence of load pockets can cause considerable market power issues. Therefore, Morgan Stanley asserts that the Commission should indeed consider whether a seller may possess the ability to exercise market power in a portion of an otherwise competitive market. To enable the Commission to do so, sellers should address known constraints in their description of the relevant geographic market in their market power filings, particularly in markets for which they are the control area operator.[211]

229. The California Commission states that while it agrees that designating a relevant geographic area will reduce uncertainty to all market participants, designation of a static geographic market in a dynamic market may defeat the purpose of market certainty and may have unintended adverse consequences over time. For example, with the implementation of locational marginal pricing (LMP) in the CAISO control area, there will be many submarket areas known as local areas. This will trigger ''false negatives'' (*i.e.*, absence of market power even when there is market power) in a control area analysis. A seller may pass both screens and receive market-based rate authority when tested against the broader geographic control area, such as the entire CAISO control area market. However, the same seller may not pass the screens when tested against a particular sub-area or local area. Accordingly, the California Commission states that the Commission should be flexible in designating geographic areas to determine market power. The Commission should designate geographic areas by considering current and reasonably foreseeable regional developments, as the Commission currently does in merger cases following DOJ/FTC merger guidelines.[212] Similarly, the Commission should consider the presence or absence of market power due to continuous developments of major market events (*e.g.*, area outages, congestion due to new market developments, and the development of load) that can have significant impact as inputs in the market power screening calculation.

230. In contrast, EEI disagrees with those commenters that would require the seller in each filing to affirmatively address with supporting evidence whether the geographic market should default to the control area or RTO/ISO area. EEI states that this requirement would defeat the purpose of having default areas to expedite and simplify the market-based rate filing process, noting that it is more efficient for any affected party to have the right to challenge the selection of the default market, as exists under the proposed regulations.[213]

Commission Determination

231. The Commission will adopt in this Final Rule its current approach with regard to the default relevant geographic market, with some modifications. In particular, the Commission will continue to use a seller's balancing authority area[214] or the RTO/ISO market, as applicable, as the default relevant geographic market.[215] However, where the Commission has made a specific finding that there is a submarket within an RTO/ISO, that submarket becomes the default relevant geographic market for sellers located within the submarket for purposes of the market-based rate analysis.

232. With regard to traditional (non-RTO/ISO) markets, our default relevant geographic market under both indicative screens will be first, the balancing

[206] APPA/TAPS at 61–62.

[207] EPSA reply comments at 9–11, citing APPA/TAPS at 56.

[208] APPA/TAPS at 53–62.

[209] State AGs and Advocates at 44–48.

[210] NRECA at 12.

[211] Morgan Stanley at 8.

[212] California Commission at 5–6.

[213] 213 EEI reply comments at 26–27.

[214] As we discuss fully below, the Commission will adopt the use of ''balancing authority area'' instead of control area. As a result we use hereon the term balancing authority area. In addition, even though commenters use the term ''control area'' we will use the term ''balancing authority area'' in our response.

[215] In addition, the Commission will continue to require sellers located in and a member of an RTO/ISO to consider, as part of the relevant market, only the relevant RTO/ISO market and not first-tier markets to the RTO/ISO.

authority area where the seller is physically located,[216] and second, the markets directly interconnected to the seller's balancing authority area (first-tier balancing authority area markets).[217] We also clarify that if a transmission-owning Federal power marketing agency (*e.g.*, the Tennessee Valley Authority, Bonneville Power Administration) is the home or first-tier market to the seller, then that seller must treat that Federal power marketing agency's balancing authority area as a relevant geographic market and file market power analysis on it just as it would any other relevant market.[218] Under the indicative screens, we will consider only those supplies that are located in the market being considered (relevant market) and those in first-tier markets to the relevant market. For non-RTO sellers, we adopt a rebuttable presumption that the seller's balancing authority area and each of its neighboring first-tier balancing authority areas are each relevant geographic markets.

233. Although a number of commenters oppose the use of the balancing authority area as the default geographic market in traditional markets, they have submitted no compelling evidence that our historical approach is inadequate or insufficient for the typical situation. Indeed, using balancing authority areas allows the Commission and public to rely on publicly available data provided for balancing authority areas that are relevant to the market-based rate analysis discussed herein. These data are accurate and generally available. We will, however, continue to allow sellers and intervenors to present evidence on a case-by-case basis to show that some other geographic market should be considered as the relevant market in a particular case.[219] We clarify that the seller must provide the Commission with a study based on the default geographic market, and we will allow sellers and intervenors to present additional sensitivity runs as part of their market power studies to show that some other geographic market should be considered as the relevant market in a particular case. This evidence would be an addition to the required study based on the relevant geographic market as referred to in this Final Rule.

234. We do not adopt the suggestion by APPA/TAPS that the seller should affirmatively address whether the geographic market should default to the balancing authority area. We believe that EPSA's argument that such a requirement would defeat the purpose of having default areas and add uncertainty into the market is more persuasive. By defining default geographic markets, we provide the industry as much certainty as possible while also providing affected parties the right to challenge the default geographic market definition and provide evidence in that regard.

235. With regard to RTO/ISO markets, we agree with many commenters that RTOs/ISOs with a sufficient market structure and a single energy market with Commission-approved market monitoring and mitigation provide strong market protections. As a general matter, sellers located in and members of the RTO/ISO may consider the geographic region under the control of the RTO/ISO as the default relevant geographic market for purposes of completing their horizontal analyses, unless the Commission already has found the existence of a submarket.

236. Where the Commission has made a specific finding that there is a submarket within an RTO/ISO, we believe that the market-based rate analysis (both indicative screens and DPT) should consider that submarket as the default relevant geographic market. This is consistent with how the Commission has treated such submarkets in the merger context. For example, in some merger orders, the Commission has found that PJM–East, and Northern PSEG are markets within PJM;[220] Southwestern Connecticut (SWCT) and Connecticut Import interface (CT) are separate markets within ISO–NE;[221] and New York City and Long Island are separate markets within NYISO.[222] Accordingly, we conclude that sellers located in these RTO/ISO submarkets should not use the entire PJM, ISO–NE and NYISO footprints as their relevant geographic markets for purposes of the market-based rate analysis. Instead, they should use as the default geographic market for their market-based rate analysis the submarkets that the Commission already has found constitute separate markets in those RTOs/ISOs.

237. We agree with APPA/TAPS that if the Commission makes a specific finding that the relevant geographic market is one other than the balancing authority area or RTO/ISO geographic region, the Commission's finding should define the default market going forward. For example, if the Commission finds that a submarket exists within an RTO, that submarket becomes the default geographic market for all sellers that own or control generation capacity within that submarket.

238. To the extent that the Commission finds that a submarket exists within an RTO/ISO, intervenors or sellers can provide evidence to the contrary (*i.e.*, the submarket, like our other default geographic markets, is rebuttable). In addition, if a seller or intervenor argues that the seller operates in an RTO/ISO submarket and presents sufficient evidence to support that conclusion, we will consider those arguments even if the Commission has not previously found that a submarket exists.

239. As a general matter, because we recognize the arguments raised by commenters that defining default geographic markets (whether balancing authority area, RTO/ISO footprint or RTO/ISO submarket) may not be appropriate in all circumstances, on a case-by-case basis, we will allow sellers and intervenors to present additional sensitivity analyses[223] as part of their market power analysis to show that some other geographic market should be considered as the relevant market in a particular case. For example, sellers or intervenors could present evidence that the relevant market is broader than a particular balancing authority area. Sellers and intervenors may also provide evidence that because of internal transmission limitations (*e.g.*, load pockets) the relevant market (or markets) is smaller than the balancing authority area, RTO/ISO footprint or RTO/ISO submarket. We believe this is a balanced approach because it establishes a presumption that the Commission will in most cases rely on default geographic markets, while at the same time, the Commission will give sellers and intervenors the opportunity to argue that the facts of a particular

[216] For applications by sellers with no physical generation assets (such as power marketers) that are affiliated with generation asset owning utilities, we will continue to evaluate the affiliate generation owner's market power when evaluating whether to grant market-based rate authority to the power marketer.

[217] Where a generator is interconnecting to a non-affiliate owned or controlled transmission system, there is only one relevant market (*i.e.*, the balancing authority area in which the generator is located.).

[218] *See, e.g., Portland General Electric Co.*, 111 FERC ¶ 61,151 at P 7 (2005); Idaho Power Co., 110 FERC ¶ 61,219 at n.6, P 10 (2005); *Florida Power Corp.*, 113 FERC ¶ 61,131 at P 17 (2005).

[219] We note that the Commission itself may explore whether an alternative geographic market is warranted based on the specific facts and circumstances of a given case.

[220] *Exelon Corp.*, 112 FERC ¶ 61,011, *reh'g denied*, 113 FERC ¶ 61,299 (2005) (*Exelon*). We note that Exelon later terminated the merger.

[221] *Wisvest-Connecticut, LLC*, 96 FERC ¶ 61,101 (2001). The parties later withdrew their application under FPA section 203.

[222] *National Grid plc*, 117 FERC ¶ 61,080 (2006).

[223] These analyses should be in addition to, not in lieu of, the analysis based on the default geographic market.

case support the use of some other geographic area as the relevant market.

240. We also provide, as discussed further below, guidance regarding the type of analysis required to rebut the default geographic markets including default markets for balancing authority areas, RTO/ISO markets, and RTO/ISO submarkets.

241. In this regard, sellers can incorporate the mitigation they are subject to in RTO/ISO markets or RTO/ISO submarkets with Commission-approved market monitoring and mitigation as part of their market power analysis. For example, if a market power analysis shows that a seller has local market power, the seller may point to RTO/ISO mitigation rules as evidence that this market power has been adequately mitigated. We believe the added protections provided in structured markets with market monitoring and mitigation generally result in a market where prices are transparent and attempts to exercise of market power will be sufficiently mitigated.

242. With respect to market concentration resulting within RTO/ISO submarkets, we will continue to consider existing RTO mitigation. The Commission will consider an existing Commission-approved market monitoring and mitigation regime already in place within the RTO/ISO that provides for mitigation of the submarket. For example, New York City will be treated as a separate default market for market-based rate study purposes. However, because it has existing In-City mitigation, we will assess whether any concerns over market power are already mitigated. We agree with Ameren that if the relevant RTO/ISO does not have in place a mitigation program for an identified submarket, the Commission may then consider whether and, if so, to what extent appropriate submarket-specific mitigation is needed.

243. In response to APPA/TAPS' statement that in practice the presumption of the RTO footprint as the default geographic market appears to be irrebuttable, this is simply not the case. The Commission carefully considers the positions and evidence submitted by parties advocating a different geographic market. Although we may have found that arguments made in a particular case were unconvincing, or that market power was adequately mitigated by existing mitigation,[224] we did, and will continue to, provide the opportunity for sellers to rebut the presumption. Moreover, as discussed above, where the Commission has made a specific finding that there is a submarket within an RTO, that submarket (not the RTO footprint) becomes the default relevant geographic market for sellers located within the submarket for purposes of the market-based rate analysis.

244. In this proceeding, we have considered expanding the default geographic region of a single RTO/ISO where contiguous RTOs/ISOs may have a common market as suggested by Ameren and find that there is insufficient support to make a generic finding that any contiguous RTOs/ISOs form a single geographic market.

245. With regard to the California Board's proposal that the Commission permit RTOs to identify submarkets within their balancing authority area, as needed to help determine possible local market power, we agree that this is an appropriate approach. However, we note that this is neither a new nor a novel approach. The Commission has historically considered the views of RTOs/ISOs in this regard and will continue to do so. We note, however, that to the extent RTOs/ISOs believe there is a market power issue within their RTO/ISO, they should notify the Commission promptly and not wait for an application by an entity seeking market-based rate authority or a current seller submitting an updated market power analysis.

246. Finally, to avoid any possible uncertainty or confusion about the RTO/ISO submarket, we identify RTO/ISO submarkets that the Commission to date has found to constitute a separate market. The Commission found submarkets in the PJM market, PJM East and Northern PSEG.[225] *In Wisvest-Connecticut, LLC*, the Commission also found two submarkets, SWCT and CT in ISO–NE.[226] In *National Grid plc*, the Commission again found two submarkets, New York City and Long Island, in NYISO.[227] These RTO/ISO submarkets will be the default geographic markets for purposes of the market-based rate analysis.

b. NERC's Balancing Authority Area and Default Geographic Area

Commission Proposal

247. In the NOPR, the Commission noted that the North American Electric Reliability Corporation (NERC) no longer uses the designation of control area since it approved the Reliability Functional Model (Functional Model). The Commission sought comment as to whether or not the adoption of the NERC Functional Model should change the criteria for specifying the default relevant geographic market, and if so, in what way it should be specified and how readily available the relevant data is.

Comments

248. Several commenters state that since NERC no longer uses control area designations, and its Functional Model refers to ''balancing authority areas,'' the Commission should modify slightly its approach to default geographic markets by simply replacing the term ''control area'' with ''balancing authority area.'' They state that such a change will align the Commission's rules with NERC's Functional Model, thus helping to avoid confusion.[228]

249. NYISO states that the control area is a valid starting point for the analysis of market-based rates. NYISO states that under the most recent version of the Reliability Functional Model posted on the NERC Web site (version 3, April 21, 2006), the ''Balancing'' and ''Market Operations'' functions appear to correlate to the traditional notion of

[224] *See, e.g., Mystic I,* LLC, 111 FERC ¶ 61,378 at P 14–19 (2005) (rejecting challenge to use of ISO–NE market as the relevant geographic market on the basis that local market power mitigation is in place: ''[W]ithout specific evidence to the contrary, we are satisfied that ISO–NE has Commission-approved tariff provisions in place to address instances where transmission constraints would otherwise allow generators to exercise local market power and that these rules and procedures will apply in the NEMA/Boston zone within ISO–NE.''); *Wisconsin Electric Power Co.*, 110 FERC ¶ 61,340 at P 19–20, *reh'g denied*, 111 FERC ¶ 61,361 at P 13–15 (2005) (rejecting challenge to use of Midwest ISO market as the relevant geographic market on basis that local market power mitigation measures exist: ''The tighter thresholds in NCAs such as WUMS in the Midwest ISO, and the resulting tighter mitigation of bids, are local market power mitigation measures'' and should adequately address specific concerns regarding the possibility that Wisconsin Electric can exercise market power in the WUMS region). *Accord AEP Power Marketing, Inc.*, 109 FERC ¶ 61,276 (2004), *reh'g denied*, 112 FERC ¶ 61,320 at P 23–25 (2005), *aff'd, Industrial Energy Users-Ohio* v. *FERC*, No. 05–1435 (D.C. Cir. Feb. 16, 2007) (use of PJM footprint as relevant geographic market; noting existence of Commission–approved market monitoring and mitigation).

[225] *See Exelon*, 112 FERC ¶ 61,011 at P 122.

[226] The Commission stated that ''clearly, during periods when transmission becomes so constrained such that no additional imports from outside the region are possible and generators located inside the region are the only suppliers that can sell inside the region, the region should be defined as a separate relevant geographic market. Such is the case with SWCT and CT in this proceeding.'' SWCT was defined as the area inside the Southern Connecticut Import interface, and CT was defined as the area inside the Connecticut Import interface, which is essentially contiguous with the state of Connecticut itself. *Wisvest-Connecticut, LLC*, 96 FERC ¶ 61,101 at 61,401–02.

[227] In *National Grid plc,* 117 FERC ¶ 61,080 at P 26, the Commission used Sellers' HHI numbers for two of the NYISO submarkets (New York City and Long Island) to assess horizontal market power, and found screen failures in both submarkets under the economic capacity analysis. *Id.* at P 31.

[228] E.ON U.S. at 19, PNM/Tucson at 21, and Indianapolis P&L at 4–5.

a control area operator for purposes of assessing competitive markets. Thus, the adoption of the Functional Model would appear to create issues more of terminology than substance. NYISO states that, whatever the terminology, the process of defining geographic markets should focus on the area in which grid operations generally facilitate the ability of generators to compete in the scheduling and dispatch of resources, and the ability of loads to purchase from such resources.[229]

Commission Determination

250. With regard to the use of the Functional Model by NERC, we agree with commenters that the Commission should modify slightly its approach to default geographic markets by replacing the term ''control area'' with ''balancing authority area.''

251. A balancing authority area means the collection of generation, transmission, and loads within the metered boundaries of a balancing authority, and the balancing authority maintains load/resource balance within this area.[230] Similar to control area, a balancing authority area is physically defined with metered boundaries that we refer to as the balancing authority area. Every generator, transmission facility, and end-use customer must be in a balancing authority area.[231] The responsibilities of a balancing authority include the following: (1) Match, at all times, the power output of the generators within the balancing authority area and capacity and energy purchased from or sold to entities outside the balancing authority area, with the load within the balancing authority area in compliance with the Reliability Standards; (2) maintain scheduled interchange and control the impact of interchange ramping rates with other balancing authority areas, in compliance with Reliability Standards; (3) have available sufficient generating capacity, and Demand Side Management to maintain Contingency Reserves in compliance with Reliability Standards; and (4) have available sufficient generating capacity, Demand Side Management, and frequency response to maintain Regulating Reserves and Operating Reserves in compliance with Reliability Standards.[232] It is the interconnection and coordination between balancing authority areas that provides a foundation for the Commission to analyze transmission limitations and other transfers of energy and provides a reasonable measure of the relevant geographic market under typical circumstances.

252. The Commission adopts in this Final Rule ''balancing authority area,'' instead of ''control area.'' We believe that such a change will align the Commission's rules with NERC's Functional Model, thus helping to avoid confusion.

c. Additional Guidelines for Alternative Geographic Market and Flexibility

Commission Proposal

253. In the NOPR, the Commission proposed to continue to provide flexibility by allowing sellers and intervenors to present evidence that the market is smaller or larger than the default market. The Commission explained that when assessing an expanded geographic market pursuant to the horizontal analysis, it looks for assurance that no frequently recurring physical impediments to trade exist within the expanded market that would prevent competing supply in the expanded area from reaching wholesale customers. The Commission stated that any proposal to use an expanded market should include a demonstration regarding whether there are frequently binding transmission constraints during historical seasonal peaks examined in the screens and at other competitively significant times that prevent competing supply from reaching the customers within the expanded market. The Commission proposed to require that such a demonstration be made based on historical data, and said it would require that a sensitivity analysis be performed analyzing under what circumstances transmission constraints would bind.

254. The Commission explained that it also considers whether there is other evidence that would support the existence of an expanded market, such as evidence that customers can access the resources outside of the default geographic market on similar terms and conditions as those inside the default geographic market. It stated that such evidence could be empirical or it could point to factors that indicate a single market. It noted that the Commission has previously stated that the operation of a single central unit commitment and dispatch function for the proposed geographic market would be an indicator of a single market, but that other evidence of a single market could include a demonstration that: There is a single transmission rate; there is a common OASIS platform for scheduling transmission service across separate control areas; or there is a correlation of price movements between the areas being considered as an expanded geographic market or other information regarding wholesale transactions in the proposed single market. The Commission stated that evidence of active trading throughout the proposed geographic market would also be considered. It stated that in determining whether two or more control areas are a single market it would weigh, on a case-by-case basis, all the factors presented. The Commission noted that once it has been established that historically there were no physical impediments to trade, there are several factors the Commission would consider, and no one factor would be dispositive. The Commission sought comment on this proposed guidance and, in particular, whether there are other factors it should consider when assessing a proposed expanded market and whether there are any factors that should be given more weight or are essential in determining the scope of the market. The Commission also asked whether it should apply the same criteria when determining whether the geographic market is smaller than the default geographic market.

Comments

255. A number of commenters agree that it is appropriate to provide sellers flexibility in presenting evidence that the appropriate geographic market is broader than the default geographic market.[233] Several state that greater Commission guidance is needed so that sellers wishing to argue for a broader market definition have clear objective criteria and can provide evidence that the Commission will find probative.

256. Puget submits that the examples listed in the NOPR provide some guidance but are still too general to be of use to a seller submitting a new market power study. It states that the Commission should: (1) Provide additional guidance on the levels of price convergence and trading activity across a proposed alternative market that will support a seller's filing; (2) be more specific regarding the level of transmission constraints that will preclude a finding of an expanded

[229] NYISO at 2–4.

[230] *See* ''Glossary of Terms Used in Reliability Standards,'' at *http://www.ferc.gov/industries/electric/indus-act/reliability/standards.asp.*

[231] *See* Basic Operating Functions and Responsibilities: A White Paper by the Control Area Criteria Task Force.*http://www.maac-rc.org/reports/documents/cactf_reliability_model_whitepaper_v2.pdf.*

[232] *See* Approved Reliability Standards. *http://www.ferc.gov/industries/electric/indus-act/reliability/standards.asp.*

[233] Indianapolis P&L at 5–6, Puget at 9–11, Ameren at 4–5, Duke at 23–24, and Avista at 5–7.

market; and (3) not rely heavily, if at all, on transmission operation factors—such as common OASIS or common unit commitment and dispatch—that are not necessarily indicative of a common market.[234]

257. Southern states that the Commission's proposed focus on evidence pertaining to frequently binding transmission constraints for purposes of considering a larger geographic market seems appropriate. However, Southern argues that the NOPR's apparent requirement of additional evidence (beyond the absence of transmission constraints) to support a larger geographic market is unnecessary. Moreover, Southern submits that evidence of a single unit commitment and dispatch function, a single transmission rate, and a common OASIS platform is not likely to exist in the absence of an RTO or ISO. Accordingly, making such evidence a requirement for a larger geographic market would render illusory the opportunity for expansion for non-RTO/ISO sellers.[235]

258. Avista agrees that the absence of these factors does not necessarily mean that a market contains impediments to trading or that wholesale customers are unable to secure supply from alternative sources. Avista supports the Commission's proposal to state what type of evidence demonstrates active trading throughout the proposed geographic market. Avista submits that a regional geographic market could and should be established based upon: (1) The presence of an actively traded liquid trading hub within the relevant defined market area; (2) transparent pricing information from that hub being widely available; and (3) the presence of extensive direct or single-wheel transmission access, both for sellers into the competitive hub market and for buyers' access to the hub market for purposes of serving load.[236]

259. Powerex supports the Commission's initial specification of evidence that may be used to support a demonstration of a broader or smaller geographic market. However, Powerex is concerned that the Commission's enumeration of relevant categories of evidence is at present a partial list, and is not sufficiently comprehensive to address the unique circumstances that are likely to be present in various regions. Powerex states that the Commission should clarify that additional types of evidence may also be used to support the propriety of a broader or smaller market definition.

260. One commenter states that the appropriate definition of the relevant geographic market can be (and very often will be) conditional—that is, when there are no binding transmission constraints on imports into the relevant control area, the relevant market appropriately encompasses a broader area than the default geographic market; and when transmission constraints into the control area are binding, the control area is the appropriate geographic market. Accordingly, sellers should be allowed (or encouraged) to present analytical results for several market definitions, dependent on the existence or nonexistence of binding transmission constraints, to sharpen the focus on when market power might be a real concern.[237]

261. APPA/TAPS generally agree that the factors set forth by the Commission for assessing whether an alternative geographic market is appropriate are reasonable, but urge that the factors be non-exclusive and non-prescriptive. In addition to the factors the Commission identified in the NOPR, APPA/TAPS suggest that a seller be allowed to point to any joint transmission planning and coordinated construction processes as evidence that the relevant market should be larger than its own control area.[238] APPA/TAPS state that a seller that is correctly advancing efforts to expand markets deserves to have that recognized and a seller that is not undertaking such efforts should live with the consequences of the resulting smaller market.

262. PPL states that if the Commission is to consider the potential existence of geographic markets smaller or larger than a control area, it should carefully consider the specific circumstances surrounding the control area of concern, and use an objective review process. That is, the Commission should consider these factors through the following means: (1) Evaluation of the historical frequency of, and times when, physical transmission constraints limit the ability to transmit power within and between control areas, RTOs, and other defined regions within which electricity system supply and demand are balanced in real-time; (2) consideration of correlations of electricity prices, and electricity price day-to-day changes, within and between control areas, RTOs, and other defined regions within which electricity supply and demand are balanced in real time; (3) reference to historical evidence of actual transactions (including swaps/exchanges, etc.) wherein power is delivered within, imported to, or exported from, control areas, RTOs and sub-regions of RTOs; and (4) consideration of operational paradigms for obtaining transmission services and the extent to which the system allows for transparent access to transmission services.[239]

263. Several commenters urge the Commission to provide flexibility by suggesting a trading hub for an alternative geographic market. E.ON U.S. and PNM/Tucson state that the Commission should take regional commercial patterns into account when evaluating proposals to use a larger or smaller market, and they support allowing a seller to present a market power analysis specific to a trading hub.[240]

264. Indianapolis P&L asks that the Commission clarify that sellers can propose different geographic definitions in their screen analyses. Indianapolis P&L states that the NOPR is unclear as to whether different geographic markets can be proposed for the indicative screen analyses or only for additional, ''second stage'' analyses, such as the DPT.[241]

265. Powerex seeks clarification on how the definition of ''home control area'' (the control area where the seller is located) applies to an entity that has small-volume contracts in multiple control areas remote from its physical location. Powerex asks whether contracts with third parties, to the extent they confer some level of ''control,'' create a multitude of home control areas. Powerex seeks additional guidance, including whether the answer to the question depends on the quantity of generation available under each contract, the level of control, whether the seller is affiliated with the transmission provider in that control area, or the remoteness of the contracted generation from the sellers' physical location.[242]

266. Duke requests clarification of whether first-tier markets, which are part of a larger RTO/ISO market (with an energy market that has central commitment and dispatch and Commission-approved market monitoring and mitigation) can be represented as the entire RTO/ISO market. For example, in the case of the Duke Energy Carolinas' control area, which is directly interconnected to the AEP transmission system, Duke queries

[234] Puget at 9–11.

[235] Southern at 24–25.

[236] Avista at 5–7.

[237] Dr. Pace at 15–16.

[238] APPA/TAPS at 54.

[239] PPL at 2–6.

[240] E.ON U.S. at 14–15, PNM/Tucson at 8–10.

[241] Indianapolis P&L at 5–6.

[242] Powerex at 13–17.

whether all of PJM would be the relevant first-tier market for purposes of determining the simultaneous import limitations into the Duke Energy Carolinas control area.[243]

Commission Determination

267. As an initial matter, we acknowledge the desire for the Commission to provide greater guidance to sellers wishing to argue for a broader or smaller market definition. We continue to believe that default geographic markets are adequate and sufficient for the typical situation. However, defaults may not be appropriate in all circumstances. Therefore, we will attempt to provide additional guidance and clarification to help inform market participants regarding the factors we believe are significant to consider when defining the market.[244]

268. First, we reiterate that reaching beyond the default geographic market in which an entity is located can mean addressing additional physical and other challenges than when trading within that market. When assessing an alternative geographic market, the Commission looks for assurance that no frequently recurring physical impediments to trade exist within the alternative geographic market that would prevent competing supply in the alternative geographic market from reaching wholesale customers. Any proposal to use an alternative geographic market (*i.e.*, a market other than the default geographic market) must include a demonstration regarding whether there are frequently binding transmission constraints during historical seasonal peaks examined in the screens and at other competitively significant times that prevent competing supply from reaching customers within the proposed alternative geographic market. We will require that a demonstration be made based on historical data and that a sensitivity analysis be performed analyzing under what circumstances transmission constraints would bind. If the seller fails to show that there are no frequently binding constraints at these critical times, then the Commission may not consider other evidence of an expanded market since we regard this as a necessary condition that must be satisfied to justify an expanded market.

269. The Commission also considers whether there is other evidence that would support the existence of an alternative geographic market. In deciding whether customers may be considered as part of an expanded geographic market, the Commission will consider evidence that they can access the resources outside of the default geographic market on similar terms and conditions as those inside the default geographic market.

270. Any such evidence submitted to show that the seller's customers have access to resources outside of their balancing authority area at terms and conditions similar to those at which they can access resources inside the balancing authority area could be empirical or it could point to factors that indicate a single market. For example, the Commission has previously stated that the operation of a single central unit commitment and dispatch function for the proposed geographic market would be an indicator of a single market. However, there are other ways to demonstrate that two or more balancing authority areas are indeed a single market. For example, other evidence of a single market could include a demonstration that: there is a single transmission rate; there is a common OASIS platform for scheduling transmission service across separate balancing authority areas; or there is a correlation of price movements between the areas being considered as an expanded geographic market or other information regarding wholesale transactions in the proposed single market. Evidence of active trading throughout the proposed geographic market would also be considered.

271. In determining whether two or more balancing authority areas are a single market, the Commission would weigh, on a case-by-case basis, all relevant factors presented. As discussed above, there are several factors the Commission would consider once it has been established that historically there were no physical impediments to trade, and no one factor or factors would be dispositive. Rather, all factors will be considered and as a whole will indicate whether there exists a single market.[245]

272. With regard to Puget's request that the Commission provide additional guidance with regard to the levels of price convergence, trading activity, and transmission constraints that define a market, no such generic finding will encompass all possibilities and, therefore, in all instances define the market. Accordingly, we will not attempt to do so here.

273. We also reject Southern's contention that the Commission has somehow rendered ''illusory'' the opportunity for entities outside RTOs and ISOs to demonstrate a larger geographic market.[246] The examples provided by the Commission of ways an entity could demonstrate a larger geographic market were just that: examples.[247] The Commission does not require an entity proposing an alternative geographic market to provide evidence other than historical transmission access. Sellers and intervenors in both RTO/ISO and non-RTO/ISO markets may present any probative evidence based on historical data of transmission availability, wholesale sales, resource accessibility, and market prices.

274. In response to Indianapolis Power & Light's comments, we clarify that when a seller submits its screen analysis, it can also propose an alternative analysis based on the use of a geographic market larger than the default geographic market. However, such proposal should be made in addition to, not in lieu of, the screen analysis based on the default geographic market.

275. With regard to using trading hubs as alternative market areas, the Commission understands that numerous electricity trading hubs have emerged over the past few years. A trading hub is a representative location at which multiple sellers buy and sell power and ownership changes hands, typically with trading of financial and physical products. For physical trades, the hub may represent a specific delivery point or set of points. Currently only select trading hubs account for the majority of physical power trading although there remains the possibility that market demand could initiate trading hubs for each balancing authority area. In evaluating market power, however, trading hub data alone does not provide a foundation for the Commission to analyze transmission limitations and other transfers of energy. Moreover, with regard to trading hubs, the combination of physical and diverse financial products, the low barriers for

[243] Duke at 28.

[244] Although the following discussion generally refers to an expanded market (*i.e.*, arguing that two or more default geographic markets constitute a single market) the same guidance is applicable for arguing that the market is smaller than the default geographic market (*e.g.*, a load pocket).

[245] We agree with Powerex that the Commission's enumeration of relevant factors it would consider is not an exhaustive list. As stated above, no comprehensive list of factors captures all factors that could indicate a single market. Accordingly, the Commission will consider additional types of evidence that may be presented on a case-by-case basis.

[246] Southern at 25.

[247] Thus, we agree with Avista that expansion of the geographic market is not limited to only those instances where there is either: a single transmission rate; a common OASIS; or operation of a single central unit commitment and dispatch function.

entry of new participants, and the unlimited potential for resale of limited physical output may not provide a reasonable measure of the relevant geographic market under typical situations, as a balancing authority area does. Therefore, while trading data may be considered in the illustration of relevant price correlation or of liquid trading activity to demonstrate that two or more balancing authority areas are indeed a single market, the Commission will not allow use of a trading hub to define a relevant geographic market.

276. With regard to one commenter's suggestion that the Commission should allow (or encourage) sellers to present analytical results for several market definitions because the appropriate definition of the relevant geographic market can be conditioned on the existence or nonexistence of binding transmission constraints, the Commission agrees in principle. The Commission provides an opportunity for sellers who fail one or more of the initial screens to present a more thorough analysis using the DPT. As the April 14 Order states ''the [DPT] defines the relevant market by identifying potential suppliers based on market prices, input costs, and transmission availability, and calculates each supplier's economic capacity and available economic capacity for each season/load condition.'' [248] In addition, in the Merger Policy Statement the Commission stated that the flows on a transmission system can be very different under different supply and demand conditions (*e.g.* peak vs. off-peak). Consequently, the amount and price of transmission available for suppliers to reach wholesale buyers at different locations throughout the network can vary substantially over time. If this is the case, the DPT analysis should treat these narrower periods separately and separate geographic markets should be defined for each period.[249]

277. The Commission believes that the DPT can address the dynamic nature of markets. Under the DPT, the amount and price of transmission available for suppliers to reach wholesale buyers at different locations throughout the network during different season/load conditions (*e.g.*, peak vs. off-peak) can be analyzed. For example, an area may become constrained only during the highest load levels, in which case the relevant geographic market could differ across seasons, and separate geographic markets could be defined for each period. However, as discussed earlier, in an effort to provide as much regulatory certainty as possible, the Final Rule adopts as the default geographic market the balancing authority area or the RTO footprint, as applicable, but allows sellers or intervenors to propose alternative markets based on historical transmission and sales data.

278. We clarify in response to Powerex that sellers should do market power studies for each balancing authority area where they own or control assets (*i.e.*, should study all balancing authority areas where generation assets they own or control are located) regardless of the quantity or location of generation they control (subject to the terms adopted herein regarding Category 1 sellers). Also, to the extent a market power study is required, sellers should study each balancing authority area where they own or control assets regardless of whether the seller is affiliated with the transmission provider in that balancing authority area. The Commission also clarifies for Duke that if the first-tier markets for a seller (whether or not the seller is a member of the RTO) are part of a larger RTO/ISO market, all of the RTO/ISO market would be a relevant first-tier market for purposes of determining the simultaneous import limitations.

d. Specific Issues Related to Power Pools and SPP

Commission Proposal

279. In the NOPR, the Commission proposed to continue its practice of designating an RTO/ISO in which a seller is located as the default relevant geographic market if the RTO/ISO has sufficient market structure and a single energy market with Commission approved market monitoring and mitigation.

Comments

280. A number of commenters urge the Commission to consider power pools as geographic market areas. Midwest Energy claims that, ''under current Commission policy, sellers of power in RTOs/ISOs with a full-fledged single central commitment and dispatch system are allowed to treat the full RTO footprint as the relevant geographic market, thereby facilitating qualification for market-based rates. Sellers in a Commission-approved RTO without a single central commitment and dispatch system are relegated to a relevant market defined by their own control area.'' [250] Midwest Energy urges the Commission to consider changing its existing policy to create a presumption that the relevant geographic market for a Commission-approved RTO is the region covered by a single transmission tariff.[251] Alternatively, Midwest Energy states that the Commission could require, in addition to a regional tariff, the implementation of a Commission-approved market monitor and a centrally dispatched energy imbalance market. It states that these changes would allow sellers to treat the Southwest Power Pool (SPP) region as the relevant geographic market.

281. Westar states that the Commission should find that a transmission region with a single OATT, non-pancaked transmission rates, a common OASIS platform for scheduling transmission, and approved market monitoring (*e.g.*, SPP) presumptively qualifies as a single region for purposes of the market power screens. Westar states that although the NOPR identifies single unit commitment and/or centralized dispatch of generation to be an important characteristic of a regional market, the Commission has not always done so. For example, the Commission did not identify this as a defining characteristic when it accepted other RTOs/ISOs as a single region for market-based rate purposes, such as New England. The Commission also did not rely upon centralized dispatch in authorizing market-based power sales across the California, New York or PJM markets. Westar states that the Commission should find that SPP meets the criteria for a single market once its energy imbalance market (EIM) becomes operational.[252]

282. In its reply comments, Southwest Coalition disagrees with those commenters requesting that SPP qualify as a single geographic region for sellers in its region once its EIM is operational. Southwest Coalition states that Westar has not presented any evidence for the Commission to change course with SPP in this rulemaking. It asserts that SPP currently has underway a variety of market implementation proceedings, of which Westar is a party, through which the Commission can make a reasoned decision regarding SPP's status. As such, Southwest Coalition states that this generic rulemaking proceeding is not the appropriate vehicle for considering Westar's request. In addition, Southwest Coalition states that Westar's request represents an improper request for rehearing of the Commission's March 20, 2006 Order in

[248] *AEP Power Marketing, Inc.,* 107 FERC ¶ 61,018 at P 106.

[249] Merger Policy Statement, FERC Stats. & Regs. Regulations Preambles July 1996–December 2000 ¶ 31,044 at 30,132.

[250] Midwest at 1–3.

[251] Midwest at 1–3, 4–8.

[252] Westar at 3–6.

SPP's market implementation proceeding. Southwest Coalition requests that, if the Commission were to consider Westar's request in this proceeding, the Commission should reject Westar's request for a Commission finding that SPP is a single geographic region for purposes of the Commission's market power screens.[253]

283. Puget argues that applying the control area default to utilities in the Pacific Northwest is arbitrary, and does not result in an accurate measurement of a seller's potential market power in the region's energy markets. According to Puget, the relevant geographic market for the purpose of measuring horizontal market power in the Pacific Northwest is the United States portion of the Northwest Power Pool, which is dominated by a transmission system operated by Bonneville Power Administration. Puget submits that many of the criteria outlined in the NOPR—particularly those addressing parallel price movements, single transmission rates, and active trading—are met in this geographic region. Utilities in the Pacific Northwest would like to have the opportunity to make a showing to the Commission that the relevant geographic market for measuring market power in their region is an area other than their home and first-tier control areas.[254]

Commission Determination

284. We decline to address whether additional regions of the country qualify as relevant geographic markets. Through this Final Rule, we set forth several examples of criteria that sellers can use in proposing an alternative geographic market. Individual sellers can challenge our default geographic market and provide evidence to support their proposal. Intervenors will have the opportunity to comment prior to the Commission rendering a decision.

e. RTO/ISO Exemption

Commission Proposal

285. In the April 14 Order, the Commission concluded that it would no longer exempt sellers located in markets with Commission-approved market monitoring and mitigation from providing generation market power analyses, on the basis that requiring sellers located in such markets to submit screen analyses provides an additional check on the potential for market power.[255] The Commission did not address this point in the NOPR.

Comments

286. In their comments in this proceeding, Reliant, NRG and FirstEnergy urge the Commission to reinstate the exemption.[256] Reliant states that reinstating the exemption would be appropriate because real-time market monitoring by an independent market monitor consistent with Commission-approved rules and Commission-approved targeted mitigation address identification of market power concerns as well as mitigation of market power in those markets and, therefore, eliminate the value of any separate market power analysis submitted by an individual seller. Reliant states that Commission-approved market monitoring and mitigation provide the Commission with a better and more sophisticated picture of market power issues in RTO/ISO markets as compared to a seller's market power analysis, which looks only at market power at a fixed moment in time.

287. Reliant states that if the Commission decides not to reinstate the exemption, it is critical that the Commission continue to use RTO/ISO markets as the default geographic market for sellers with generation located in those markets. Reliant states that the key to the determination of relevant geographic markets is the extent to which sellers can compete in the defined market. RTO/ISO markets with centralized markets provide a platform for all sellers located in the pertinent RTO/ISO market to compete. Thus, Reliant states that it is entirely appropriate to consider such markets as the default market unless and until an intervenor can show that this is no longer appropriate (*e.g.*, due to transmission constraints).[257]

288. In its reply comments, PSEG states that while it believes that the RTO/ISO exemption would be warranted at least for regions with pervasive market monitoring unit (MMU) oversight such as PJM, it recognizes that some affected parties may not be comfortable with a blanket exemption. It suggests that the Commission's regulations should take account of the fact that the Commission has approved comprehensive MMU oversight of markets and that MMUs take their duties seriously and routinely exercise their authority. Accordingly, PSEG proposes that evidence of active MMU oversight supply the basis for obviating the need to conduct a market power study for a particular zone or sub-zone of an RTO or ISO.[258]

289. APPA/TAPS, in contrast, state that reinstating the RTO/ISO exemption would represent an abdication of the Commission's responsibilities.[259]

Commission Determination

290. The Commission declines the request that it reinstate the pre-April 14 Order exemption for sellers located in markets with Commission-approved market monitoring and mitigation from providing generation market power analyses. The Commission will continue to require generation market power analyses from all sellers, including those in RTO/ISO markets. All sellers are required to receive authorization from the Commission prior to undertaking market-based rate sales, and as discussed herein, all new applicants for market-based rate authority are required to, among other things, provide a horizontal market power analysis. The first step for a seller seeking market-based rate authority is to file an application to show that it and its affiliates do not have, or have adequately mitigated, market power. Sellers can refer to RTO/ISO monitoring and mitigating as a factor. We believe that a single market with Commission-approved market monitoring and mitigation and transparent prices provides added protection against a seller's ability to exercise market power but cannot replace the generation market power analysis.

291. To address Reliant's concern, we note that, as discussed above, we will use RTO/ISO markets (including Commission findings with regard to RTO/ISO submarkets) as the default geographic market for the indicative screens for sellers with generation in those markets.

8. Use of Historical Data

Commission Proposal

292. The Commission proposed in the NOPR to retain the ''snapshot in time'' approach for the indicative screens, so that sellers are required to use the most recently available unadjusted 12 months' historical data. The

[253] Southwest Industrial Customer Coalition reply comments at 2–9.

[254] Puget at 9–11.

[255] 107 FERC ¶ 61,018 at P 186. The Commission had previously stated that all sales, including bilateral sales, into an ISO or RTO with Commission-approved market monitoring and mitigation would be exempt from the Supply Margin Assessment test and, instead, would be governed by the specific thresholds and mitigation provisions approved for the particular market. *AEP Power Marketing, Inc.,* 97 FERC ¶ 61,219 at P 176 (2001).

[256] Reliant at 6–7; NRG at 7; and FirstEnergy at 33.

[257] Reliant at 6–7.

[258] PSEG reply comments at 5–6.

[259] APPA/TAPS reply comments at 2–3.

Commission stated that historical data are more objective, readily available, and less subject to manipulation than future projections. The Commission proposed to continue to permit sellers to make adjustments to data that are essential to perform the indicative screens provided that the seller fully justifies the need for the adjustments, justifies the methodology used, provides all workpapers in support, and documents the source data.

293. However, the Commission proposed to allow, for the DPT analysis, sellers and intervenors to account for changes in the market that are known and measurable at the time of filing.[260] The Commission noted that this proposal mirrors the Commission's approach in connection with its merger analysis. Sellers and intervenors proposing known and measurable changes to be considered in the DPT analysis would bear the burden of proof for their adjustments to historical data. The Commission sought comment on whether the Commission should provide a limitation on the time period past the historical test period for which sellers can account for changes, what that time period should be, and how flexible or inflexible that limitation should be. In addition, the Commission sought comment on exactly what types of changes should be allowed and under what circumstances.

Comments

294. Various commenters generally support the Commission's proposal to use historical data for the indicative screens and allow known and measurable changes for the DPT.[261] Some suggestions made as to what should be considered known and measurable changes include: Allowing only changes that occur between updated market power analysis filings [262] and allowing only publicly available data or company information.[263] Powerex expresses concern that known and measurable changes may not be publicly available.[264] PG&E suggests that the Commission evaluate on a case-by-case basis whether the seller or intervenor can prove that the change is both foreseeable and reasonable. It says that the Commission should not impose a time restriction on such changes provided that the seller provides the necessary support for changes that it claims are known and measurable.[265]

295. A number of commenters suggest that sellers should be permitted to account for known and measurable changes in both the indicative screens and the DPT.[266] Southern states that the Commission ''should not * * * restrict the ability of parties to provide the Commission with the best possible information and analysis.'' [267] Duke states that in all instances the objective should be to obtain the most accurate and timely assessment of the seller's ability to exercise market power under current market conditions.[268]

296. NRECA states that the screens should incorporate imminent changes and that an example of known and measurable changes that should be included in initial applications and triennial filings is the capacity freed up by expiring long-term contracts. It submits that these contracts will expire on a known schedule and, if the market is competitive, the seller should not be allowed to assume that the capacity will remain committed to the buyer.[269]

297. PPL argues that long-term contracts should retain the current definition as those expiring in one year or more, and recommends not considering contracts that take effect after one year but before the triennial update is due. It argues that buyers could withhold signing contracts and force a market power finding. PPL also notes that a notice of change in status must be filed at the expiration of contracts that increase the seller's capacity by 100 MW or more and that the Commission can initiate a section 206 investigation at that point if need be.[270]

Commission Determination

298. We will continue to require the use of historical data for both the indicative screens and the DPT in market-based rate cases. The indicative screens are designed as a tool to identify those sellers that raise no generation market power concerns and can otherwise be considered for market-based rate authority. Accordingly, the indicative screens are conservative in nature and not generally subject to debates over projected data, which may unnecessarily prolong proceedings and create regulatory uncertainty. However, in light of adopting a regional approach with regard to regularly scheduled updated market power analyses, we will require the use of the actual historical data for the previous calendar year. Requiring all sellers in a region to provide analyses using the same data set further enhances the Commission's ability to evaluate market power and identify any discrepancies between market studies.

299. After careful consideration of the comments received, the Commission will not adopt the NOPR proposal that the DPT analysis allow sellers and intervenors to account for changes in the market that are known and measurable at the time of filing. Instead, the Commission will adopt its current practice that sellers are required to use, in the preparation of a DPT for a market-based rate analysis, unadjusted historical data and, consistent with the above discussion, the Commission will require the use of the actual historical data for the previous calendar year. The Commission has stated that historical data are more objective, readily available, and less subject to manipulation than future projections.

300. We acknowledge that the Commission's approach in its merger analysis requires applicants and intervenors to account for changes in the market that are known and measurable at the time of filing. However, we find that the purpose of using the DPT in market-based rate proceedings is different from that in merger analysis. Intrinsically, a merger analysis is forward-looking to identify what effect, if any, there will be on competition if the proposed merger is consummated. Even though the Commission has the ability to reopen a merger proceeding under its section 203(b) authority, it is difficult and costly to undo a merger, so the Commission is cognizant of the need to analyze what might happen as a result of a proposed merger and put any necessary mitigation in place prior to consummation of the merger.

301. In contrast, the market-based rate analysis is a ''snapshot in time'' approach. When the Commission evaluates an application for market-based rate authority, the Commission's focus is on whether the seller passes both of the indicative screens based on unadjusted historical data. Likewise,

[260] *See* 18 CFR 35.13(a).

[261] *See, e.g.*, EEI at 23, PPL at 17–19; Powerex at 18–19.

[262] *See, e.g.*, Ameren at 6. Ameren proposes that if a seller chooses to rely on an historical period with no changes, the Commission should honor that choice and not allow intervenors to introduce suggested known and measurable changes. Conversely, if a seller proposes to adjust the historical period for certain known and measurable changes, Ameren states that the Commission should permit intervenors to introduce competing known and measurable changes. *Id.* at 6–7.

[263] Drs. Broehm and Fox-Penner at 12–13 (any adjustments to historical base year must be known and measurable at the time of filing; new capacity additions should only be accounted for if they are on-line or under construction).

[264] Powerex at 18–19.

[265] PG&E at 9–10.

[266] PG&E at 2; Southern at 25–26; Duke at 26; NRECA at 21–23.

[267] Southern at 26.

[268] Duke at 26.

[269] NRECA at 21–23. *See also* APPA/TAPS at 13–15.

[270] PPL reply comments at 3–4.

when a seller fails one of the screens and the Commission evaluates whether that seller passes the DPT, the Commission's focus is on whether the seller passes the DPT based on unadjusted historical data. The Commission's grant of market-based rate authority is conditioned, among other things, on the seller's obligation to inform the Commission of any change in status from the circumstances the Commission relied upon in granting it market-based rate authority. As such, the Commission's market-based rate program is designed to require sellers to report, and enable the Commission to examine, changes in facts and circumstances on an ongoing basis. Such a reporting requirement provides the Commission with ongoing monitoring in addition to its right to require any market-based rate seller to provide an updated market power analysis at any time. Accordingly, the market-based rate change in status reporting requirement allows the Commission to evaluate changes when they actually happen rather than relying on projections, making it unnecessary and redundant for the Commission to allow sellers to account for known and measurable changes in the DPT for market-based rate purposes. For these reasons and the reasons explained in the April 14 and July 8 Orders and existing Commission precedent, the Commission reaffirms that the indicative screens and DPT analyses should be based on unadjusted historical data.

9. Reporting Format

Commission Proposal

302. In the NOPR, the Commission proposed to require all sellers to submit the results of their indicative screen analysis in a uniform format to the maximum extent practicable and appended a proposed format. This format, provided in Appendix C of the NOPR, was intended to promote consistency and aid the Commission in the decision-making process. The Commission sought comment on this proposal.

Comments

303. Although only a few comments were received on this topic, those comments support the proposal to adopt a uniform reporting format for the indicative screens. APPA/TAPS suggest that the proposed uniform format should help all market participants, especially when assessing the filings of a number of public utilities as part of the proposed regional review process. APPA/TAPS state that the uniformity should also help the Commission analyze market-based rate filings on a consistent basis, thus increasing market participant confidence in those assessments.[271] Other commenters concur with the Commission's proposal for a uniform reporting format. They state that a uniform reporting format will increase consistency and thus aid the Commission in its decision making process.[272]

304. One commenter suggests formatting and presentation changes to the NOPR's Appendix C reporting form. These changes include creating sections for items such as the calculation of seller and market uncommitted capacity and rearranging some in a more logical fashion.[273]

Commission Determination

305. We will adopt the reporting format as proposed in the NOPR, maintaining the same order of items as in the form provided in Appendix C of the NOPR, but note that this form now appears as Appendix A of this Final Rule. We believe standardizing the submission format has benefits to all market participants. As noted, it appears that commenters as well are generally supportive of this proposal to require all sellers to submit the results of their indicative screen analyses in a uniform format.

306. Also, we will adopt many of the formatting changes suggested in the comments. The row letter will be the first column and a better delineation of sections will increase the comprehensibility of the form. The revised form can be found in Appendix A.[274]

10. Exemption for New Generation (Formerly Section 35.27(a) of the Commission's Regulations)

a. Elimination of Exemption in Section 35.27(a)

Commission Proposal

307. The Commission's regulations provide that any public utility seeking authorization to engage in market-based rate sales is not required to demonstrate a lack of market power in generation with respect to sales from capacity for which construction commenced on or after July 9, 1996.[275] In the NOPR, the Commission noted that when it established the exemption in Order No. 888 it indicated that it would consider whether a seller citing § 35.27(a) nevertheless possesses horizontal market power if specific evidence is presented by an intervenor.[276]

308. The Commission stated in the NOPR that although it remains committed to encouraging new entry of generation, it is concerned that the continued use of the § 35.27(a) exemption may become too broad and, over time, would encompass all market participants as all pre-July 9, 1996 generation is retired. Accordingly, the Commission proposed in the NOPR to eliminate the exemption in § 35.27(a) and to require that all new sellers seeking market-based rate authority on or after the effective date of the Final Rule and all sellers filing updated market power analyses on or after the effective date of the Final Rule must provide a horizontal market power analysis of all of their generation, whether or not it was built after July 9, 1996. Because the Commission allows a seller to make simplifying assumptions where appropriate and to submit a streamlined analysis, the Commission explained that any additional burden imposed on sellers by this reform would be minimal. In addition, the Commission anticipated that those entities that otherwise would have relied on the exemption would, in most cases, qualify as Category 1 sellers and therefore no longer be required to file updated market power analyses as a routine matter. The Commission sought comment on this proposal.

Comments

309. Many commenters support the Commission's proposed elimination of the § 35.27(a) exemption, stating that there should be a level playing field for market-based rate sellers so that all market participants would be required to perform the generation market power screens.[277] A number of commenters support the Commission's position that there is a valid concern that over time the exemption would encompass all generation as older generating units are

[271] APPA/TAPS at 35.

[272] Drs. Broehm and Fox-Penner at 12.

[273] Dr. Pace at 8–9.

[274] The ''Workpapers'' column is meant to provide an easy way to find sources and ensure that all submissions are properly sourced. Hence, the items in that column (*e.g.*, ''Workpaper 5'') were merely meant to be illustrative and do not require that information be submitted on specific workpapers or that workpapers be submitted in a particular order.

[275] 18 CFR 35.27(a). The regulation reads: ''Notwithstanding any other requirements, any public utility seeking authorization to engage in sales for resale of electric energy at market-based rates shall not be required to demonstrate any lack of market power in generation with respect to sales from capacity for which construction has commenced on or after July 9, 1996.

[276] NOPR at P 67.

[277] Progress Energy at 2; PG&E at 10; FirstEnergy at 9; TDU Systems at 2; New Jersey Board at 2; NASUCA at 7; Drs. Broehm/Fox-Penner at 13.

retired and new generation is built.[278] Several commenters state that the Commission correctly observes that the indefinite continuation of the exemption would ultimately result in the automatic grant of market-based rate authority to all sellers as pre-1996 generation is retired.[279] They further state that eliminating the exemption will not impose significant new burdens, deter new entry into a market, or create any unreasonable disincentive or impediment for the construction of future generating capacity.[280] Contrary to the assertions of several commenters, FirstEnergy states that the elimination would encourage merchant power developers to expand generation in markets where they do not already have a dominant position which, in turn, would dilute market power concerns in these markets.

310. NRECA and APPA/TAPS maintain that, despite EPSA's, Mirant's, and PPL's assertions to the contrary,[281] the Commission did not create the exemption as an incentive to encourage new generation investment.[282] APPA/TAPS elaborates further, agreeing with the Commission that many new entrants would qualify as Category 1 sellers and, therefore, would not have to submit updated market power analyses and that other entrants could make simplifying assumptions to demonstrate that they qualify for market-based rate authority.[283] These commenters contend that the benefits of eliminating the exemption far outweigh any added burdens to ensure that all market participants are treated equally and to ensure that rates for jurisdictional sellers are just and reasonable.[284]

311. In support of the elimination of the § 35.27(a) exemption, NASUCA acknowledges that under current procedures, if all the generation owned or controlled by an applicant for market-based rate authority and its affiliates in the relevant control area is new generation, such seller is not required to provide a horizontal market power analysis because of the exemption under § 35.27(a).[285] NASUCA asserts that under the current rule, there is no limit on the amount of post-July 9, 1996 generation that could be exempt from the Commission's analysis of market power. In addition, a commenter explains that the potential to exercise market power has no relation to whether generating plants were built before or after 1996.[286] ELCON suggests that generators that were built after July 9, 1996 are capable of exercising market power.[287] In addition, FirstEnergy points out that merchant power plant developers have begun to aggregate fleets of newer generating plants to which this exemption is applicable, and may now be able to exercise generation market power.[288] PG&E adds, ''in situations where all generation owned or controlled by an applicant and its affiliates in the relevant market is new generation, should they control sufficient generation, the applicants and its affiliates may freely exercise market power.'' [289] In addition, Morgan Stanley supports elimination of the exemption, stating that maintaining the exemption would have unintended consequences going forward.[290]

312. Among those who oppose elimination of the exemption, Constellation asserts that it would send an unfavorable signal to market participants that the rules may be changed with a retroactive effect, which in turn would deter investment.[291] Constellation also contends that the Commission offers no support and/or analysis to demonstrate its inference that older generating units will be retired in significant quantities to make a substantial difference to the screening analysis of any seller. PPL submits, among other ill-effects, that the elimination will deter investment in areas where there is a limited supply and the new entrant may be deemed pivotal. In addition, PPL contends that some sellers relied on the presumption that they would not need to demonstrate a lack of market power in financing, constructing, and operating their new power plants.[292]

313. EPSA opposes the elimination of the exemption under § 35.27(a). EPSA states that the electric industry needs incentives for new generation and does not need disincentives if capital is to be invested on a timely basis to meet future demand and enhance competition.[293] EPSA asserts that the exemption encourages the development of competitive supply outside of organized markets.[294] Similarly, NRG contends that the elimination of the § 35.27(a) exemption will delay and deter investment in load pockets. NRG also argues that eliminating the exemption runs counter to the Commission's policy of encouraging investment in electric power infrastructure to enhance reliability and market liquidity.[295]

314. In addition, EPSA argues that the purpose of the exemption was to encourage new generation investment by competitive suppliers, especially in areas of the country that are mostly dominated by utility-owned generation.[296] Specifically, EPSA explains that it is in these regions of the country where affiliated generation is largely treated as native load and, thus, is excluded from the market power analysis even though it represents most of the capacity in the region.[297] EPSA explains that, even if a small increment of competitive supply is introduced into the market, the analysis might detect market power when measured against relatively small existing generation. Therefore, without the exemption, a new competitive supplier would fail the test and would have to utilize cost-based rates.[298]

315. Allegheny argues that the Commission overlooks the reason why it initially adopted the exemption. Allegheny states that, in Order No. 888, the Commission determined that long-term generation markets are competitive.[299] Allegheny further argues that ''the Commission cannot 'gloss over' its prior reasoning without discussion, and without showing that there has been a fundamental change in facts and circumstances that have [sic] caused long-term markets to be no

[278] *See* PG&E at 10; APPA/TAPS at 27; NRECA at 11; Carolina Agencies at 1.

[279] APPA/TAPS at 27; NRECA at 11; Carolina Agencies at 1.

[280] *See* FirstEnergy at 10; APPA/TAPS at 27; NRECA at 11; Carolina Agencies at 1.

[281] EPSA at 12–13; Mirant at 11; PPL at 19–20.

[282] NRECA reply comments at 11; APPA/TAPS reply comments at 16–17.

[283] *See* APPA/TAPS at 27.

[284] APPA/TAPS at 27; NRECA at 11; Carolina Agencies at 1.

[285] NASUCA at 7.

[286] Drs. Broehm/Fox-Penner at 13.

[287] ELCON at 6.

[288] *See* FirstEnergy at 9–10.

[289] PG&E at 10.

[290] Morgan Stanley at 13–14.

[291] Constellation at 30.

[292] PPL at 19–20.

[293] EPSA at 12.

[294] EPSA reply comments at 6.

[295] NRG at 2.

[296] EPSA at 13.

[297] In its reply comments NASUCA disagrees, submitting that there are other regions where a seller with a fleet of newer exempted generating plants could exercise market power or bid the output strategically to drive prices up. NASUCA reply comments at 4–5.

[298] EPSA at 13.

[299] Allegheny at 8–9 (citing *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities,* Order No. 888, FERC Stats. & Regs., Regulations Preambles, January 1991–June 1996 ¶ 31,036 at 31,657 (1996), *order on reh'g,* Order No. 888–A, FERC Stats. & Regs. Regulations Preambles July 1996–December 2000 ¶ 31,048 (1997), *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 part and rev'd in 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)).

longer competitive.'' [300] PPL asserts that the Commission in Order No. 888 recognized the power that the opportunity of free entry has to eliminate market power concerns and stated that open access advancements removed structural impediments for new entrants competing with existing market participants.[301]

316. Mirant and EPSA expand on arguments that eliminating the exemption will deter investment. They argue that, when reserve levels are tight in a control area where the host utility has lost or forgone its market-based rate authority, a competitive supplier would have to weigh the risks as to whether the Commission would authorize it to make market-based rate sales if it were to build a new asset in that control area.[302] They contend that there is no incentive for a competitive supplier to build new generation if its sales will be mitigated at some level of cost-based rates.[303] In particular, Mirant explains that if a municipal utility issued a request for proposals (RFP) for 600 MW of power commencing in 2010 and terminating in 2020, with the current exemption competitive suppliers could bid on the RFP knowing that the supplier would be authorized to sell the output of its new generating station at market-based rates. However, Mirant asserts that if the exemption were eliminated, a supplier would have to get Commission approval for market-based rate sales prior to bidding on the RFP. [304]

317. Mirant disagrees with the Commission's contention that eliminating the exemption would not affect many sellers and that the cost of compliance would be minimal. Mirant states that five of its subsidiaries would have to file updated market power analyses if the exemption were eliminated because they own more than 500 MW in the relevant market or control area and would not qualify as Category 1 sellers. Mirant argues that its cost of compliance would increase because it would have to prepare four updated market power analyses, each costing $20,000 to prepare and file.[305] In its reply comments, APPA/TAPS state that Mirant's increased cost is paltry compared to the over $3.4 billion in generation revenues reported by Mirant in 2005, which APPA/TAPS suggest is in no small part due to Mirant's market-based rate sales.[306]

318. Some commenters contend that the Commission's concern that over time all older generation will be retired and the Commission will be unable to analyze sellers for market power is not a valid concern in the immediate or mid-term; they state that the most recent retirement announcements concern generation assets that were built in the 1940s and 1950s.[307] PPM and Allegheny argue that the Commission offers no evidence or observations to quantify the magnitude of future retirements.[308] Some commenters assert that, in order for this speculative concern to become realistic, the retirement of generating units that were constructed in the 1980s would have to become commonplace, and it will take decades for this situation to materialize. As such, they suggest that the Commission revisit this issue in 5 to 10 years rather than act prematurely.[309]

319. PPM suggests that, if the Commission wishes to limit the overall amount of generation that is exempt for purposes of conducting a horizontal market power analysis, an alternative approach would be to keep the exemption and phase in exempted units over time. Thus, units that were built after 1996 but before 1999 would lose the exemption in 2010, while facilities built in 2001 would lose it in 2015, and so on.[310]

Commission Determination

320. The Commission adopts the proposal set forth in the NOPR and eliminates the exemption provided in § 35.27(a). All sellers seeking market-based rate authority, or filing updated market power analyses, on or after the effective date of this Final Rule must provide a horizontal market power analysis for all of the generation they own or control. As a number of commenters recognize, over time the exemption would become too broad and would encompass all market participants as pre-July 9, 1996 generation is retired. In addition, we note that even assuming for the sake of argument that there are not a large number of retirements, the current exemption would allow sellers to grow unabated as load increases and could result in such sellers gaining a dominant position in the market without being subject to any horizontal market power analysis. Thus, continuing the exemption would result in unintended consequences where all sellers would be given an automatic presumption that they lack market power in generation. Accordingly, the Commission finds that eliminating the exemption in § 35.27(a) and requiring every new seller to submit a generation market power analysis will allow the Commission to ensure that the seller does not have market power in generation.[311]

321. We do not believe that this change will have an adverse effect on the majority of sellers that have previously relied on the § 35.27(a) exemption. The sellers that have taken advantage of the exemption will largely qualify as Category 1 sellers, and thus will be unaffected to the extent that they will not be required to file a regularly scheduled updated market power analysis. For those sellers seeking market-based rate authority for the first time (*e.g.*, building new generation facilities), and those that do not qualify as Category 1 sellers, there are several mechanisms or alternatives that can help to minimize the burden of submitting a horizontal market power analysis. For example, a seller, where appropriate, can make simplifying assumptions, such as performing the indicative screens assuming no import capacity or treating the host balancing authority area utility as the only other competitor.[312] We expect that, for most sellers, the cost of compliance and document preparation occasioned by the elimination of § 35.27(a) will not be burdensome. To the extent that there are greater costs for some sellers, we find that the benefit of ensuring that markets do not become less competitive over time outweighs any additional costs. Equally important, the elimination of § 35.27(a) will place all sellers on the same footing. On this basis, we disagree with commenters that eliminating the exemption would send an unfavorable

[300] Allegheny at 9 (citation omitted).

[301] PPL at 20.

[302] Mirant at 11–12; EPSA at 13–14.

[303] EPSA at 13; Mirant at 12.

[304] Mirant at 11–12. Mirant elaborates: ''In calculating the pivotal supplier and market share screens, an applicant is allowed to deduct from its installed capacity the amount of capacity that is committed under a long-term sale, but the seller is presented with a Catch-22. The seller cannot enter into a long-term sales contract at market-based rates without prior Commission authorization, but the seller cannot pass the applicable indicative screens without deducting the amount of the capacity sold under long-term contract. Retaining the exemption eliminates this problem and is consistent with Commission precedent regarding competitive forward markets.'' *Id.* at 12.

[305] Mirant at 11.

[306] APPA/TAPS reply comments at 17.

[307] Mirant at 10; EPSA at n.2, citing for example: *http://pjm.com/planning/project-queues/gen-retirements/20060601-pjm-gen-retir-list-public-future.pdf.*

[308] PPM at 6; Allegheny at 8.

[309] EPSA at 15; Mirant at 10.

[310] PPM at 6.

[311] We note that the Commission may change its policy if it provides, as it does here, a reasoned analysis indicating that prior policies are being deliberately changed and the basis for that change. *E.g., B&J Oil and Gas* v. *FERC*, 353 F.3d 71 (D.C. Cir. 2004).

[312] *See* April 14 Order, 107 FERC ¶ 61,018 at P 69, 117.

signal to market participants and deter investment.

322. We also disagree with commenters that find our rationale for adopting the exemption in 1996 necessarily constrains our decision making at this time. In light of our experience over the past decade and our desire to have a more rigorous market-based rate program, combined with the concern that over time generation will be retired, we believe a more conservative approach for granting market-based rate authority is appropriate and will provide us a better means to ensure that customers are protected.

323. We find unpersuasive Mirant's concern that, if the § 35.27 exemption were eliminated, a seller would have to get Commission approval for market-based rate sales prior to bidding on an RFP. If Mirant is concerned that certain RFPs require, among other things, that all bidders have in place all regulatory requirements including any applicable market-based rate authority, we find that RFPs typically afford bidders ample opportunity to put together their bids and put in place any necessary regulatory approvals. In this regard, we note that if a potential seller wishes to participate in an RFP but does not have market-based rate authority, the seller can file for such authorization and request expedited treatment and the Commission will use its best efforts to process the request as quickly as possible.

324. With regard to the specific argument raised by Mirant, if a prospective seller wins an RFP, then the capacity would be counted as committed capacity, and therefore would not adversely affect the results of the seller's generation market power screen (which analyzes uncommitted capacity). If the entity loses the RFP, then it would not build the plant. In either case, the need for market-based rate authorization does not appear to discourage new investment by competitive suppliers as Mirant suggests.

325. Some commenters assert that the retirement of generating units that were constructed in the 1980s would have to become commonplace before the Commission's concern is realized that over time all older generation will be retired. Others contend that it will take decades for this situation to materialize. However, commenters have provided no evidence that the elimination of § 35.27(a) will create a regulatory barrier to new construction or otherwise depress the building of new generation facilities, and we need not wait for an inevitable adverse circumstance to materialize.

326. Finally, we will not implement PPM's suggestion that we retain the exemption and apply a phasing in approach whereby generating units would lose the exemption over time based on the date on which the units were built. Such an approach would create several ''classes'' of generation facilities which would result in confusion for both the Commission and market participants. This confusion would become more acute in situations where market participants may own a number of generating facilities located in the same balancing authority area or relevant geographic market, each of which may be considered a different ''class'' of generator in terms of filing horizontal market power analyses. Moreover, given the regional review and schedule for updated market power analyses discussed below in this rule, we believe that a phased-in approach would become overly problematic and unmanageable for market participants as a whole. Therefore, we will not accept PPM's suggestion.

b. Grandfathering

Comments

327. EPSA and Mirant suggest grandfathering units for which construction commenced between July 9, 1996 and May 19, 2006, the date of issuance of the NOPR, when generation owners were put on notice that the Commission was considering eliminating the exemption in § 35.27(a).[313] Constellation proposes that the exemption not be eliminated entirely but be limited to generation with construction that commenced on or after July 9, 1996, but before the effective date of the Final Rule in this proceeding.[314] Constellation and EPSA also contend that this would be consistent with the Commission's prior decision to grandfather from PJM's mitigation any generating units that were built in reliance on the post-1996 exemption.[315]

328. Although NASUCA agrees with the Commission's proposal to eliminate the new generator exemption, NASUCA raises a concern about the prospective treatment of sellers with generating plants built after July 9, 1996 that initially received market-based rate authority without any generation market power assessment. NASUCA notes that its understanding is that, ''the Commission would effectively ''grandfather'' the market-based rate status for owners of these newer power plants,[316] at least until the time of the next applicable triennial review, when a market power analysis would be required for continuation of market-based rate authority.'' [317] Specifically, NASUCA explains that a Category 2 seller who recently obtained market-based rate authority, could have up to three years of future market-based rate sales with no review of its horizontal market power, while any that fall into Category 1 would be exempted entirely from the triennial review process and thus ''grandfathered'' indefinitely and able to sell at market-based rates without passing any market power test. If this ''grandfathering'' is not intended, then, according to NASUCA, the Commission should clarify that new market power assessments must be made now for those sellers whose market power has never been reviewed.[318] Otherwise, NASUCA contends that their rates could be vulnerable to challenge because they are established solely on the basis of market price.[319]

Commission Determination

329. We will not adopt commenters' proposals with regard to the grandfathering of any generating units that were built relying on the exemption in § 35.27(a). As discussed above, we find establishing ''classes'' of generation facilities would result in confusion for both the Commission and market participants. In this regard, no

[313] EPSA at 15; Mirant at 13.

[314] *See* Constellation at 31; PPL reply comments at 20.

[315] Constellation at 31, citing *PJM Interconnection, LLC,* 110 FERC ¶ 61,053 at P 60–62 (grandfathering the exemption from mitigation for generating units for which construction commenced on or after the date the exemption became effective and before the date when PJM filed its proposal to eliminate the exemption for all generation units) (*PJM*), *order on reh'g,* 112 FERC ¶ 61,031 at P 38 (2005) (*PJM II*), *order on reh'g,* 114 FERC ¶ 61,302 (2006); EPSA at 16–17.

[316] NASUCA at 10 n.12, ''[T]he Commission would require that all *new* applicants seeking market-based rate authority on or after the effective date of the final rule issued in this proceeding, whether or not all of their or their affiliates' generation was built after July 9, 1996, must provide a horizontal market power analysis of their generation.'' *Citing* NOPR at P 71 (emphasis added).

[317] *Id.* at n.13, ''[W]ith regard to triennial reviews, the Commission's proposal to eliminate the section 35.27(a) exemption would require that, in its triennial review, a seller must perform a horizontal market power analysis of all of its generation regardless of when it was built, thus eliminating any special treatment of generation built after July 9, 1996.'' *Citing* NOPR at P 72.

[318] NASUCA at 10–11.

[319] *Id.* at 11, *citing FPC* v. *Texaco, Inc.,* 417 U.S. 380 (1974) (stating that the prevailing price in the marketplace cannot be the final measure of just and reasonable rates) (*Texaco*). *See also* NASUCA reply comments at 7–8 (asserting that for any grandfathered sellers the market is the final determinant of price, an impermissible result under *Texaco*.)

commenter has demonstrated that harm would result from having to submit a horizontal market power analysis, and no commenter has claimed that it would lose its financing or that its financing would be adversely affected as a result of the elimination of the exemption in § 35.27(a). Moreover, as the Commission stated in Order No. 888, intervenors could present evidence that a seller seeking market-based rates for sales from new generation possesses market power, and sellers were aware that they may have to submit a horizontal market power analysis even if their generation fell within the exemption.[320] Therefore, we will require that all sellers seeking market-based rate authority for the first time on or after the effective date of the Final Rule in this proceeding must provide a horizontal market power analysis that includes all generation that the seller owns or controls.

330. All existing sellers that fall in Category 2 must provide a horizontal market power analysis that includes all generation that each seller owns or controls when it files its regularly scheduled updated market power analysis. To the extent a Category 1 seller acquires enough generation to be reclassified as a Category 2 seller, that seller will be required to submit a change in status report and provide a horizontal market power analysis.

331. Further, with regard to *PJM,* in establishing whether units constructed after July 9, 1996 should be exempt from PJM's existing market power mitigation rules, we initially approved the post-1996 exemption based on the concern that the price cap regulation or the mitigation rules in PJM might deter market entry and would create certain equity issues. However, we reconsidered our position and found that the exemption was unduly discriminatory by creating two classes of reliability must run generators: one that is price or offer capped and another that is not. Equally important, other RTOs/ISOs applied local market mitigation rules to all generation within their respective areas regardless of when the generator was built, and we determined that comparable authority for PJM would allow it to address local market power issues.[321] We concluded that units built on or after July 9, 1996 had the same ability to exercise market power as counterparts that were built prior to July 9, 1996. Accordingly, the Commission terminated the blanket exemption, but in the case of units that were built with the expectation that they would not be subject to mitigation, the Commission allowed the exemption to be grandfathered.[322]

332. Our reasons for grandfathering units in PJM are dissimilar enough that our holding in the *PJM* orders should not affect our decision here. The factors that led to the establishment and later the termination of the exemption from mitigation in PJM are unrelated to the reasons for instituting and, now, eliminating the express exemption in § 35.27(a). In *PJM* and *PJM II,* the Commission considered whether local market power mitigation might deter new entry and whether new units were built with the expectation that they would not be subject to mitigation. The Commission grandfathered units that could reasonably have relied on the exemption after it went into effect in their zone.[323] In contrast, in this proceeding the Commission desires a more rigorous market-based rate program and is concerned that over time generation will be retired leaving less and less generation subject to our horizontal analysis or sellers relying on the § 35.27 exemption will otherwise grow to a degree that they have market power in the relevant market in which they are located. The Commission's primary statutory obligation under FPA sections 205 and 206 is to ensure that rates are just and reasonable, and we believe the elimination of the exemption will better provide us with the ability to screen all market participants' ability to exercise horizontal market power regardless of whether their generation units were constructed before or after July 9, 1996. Therefore, we will not allow any grandfathering as part of this proceeding.

333. NASUCA's concerns regarding entities that originally enjoyed the § 35.27 exemption are addressed by our decision, discussed below in the Implementation Process section of this Final Rule, to require a seller that believes it qualifies as Category 1 to make a filing with the Commission at the time that its updated market power analysis for the seller's region would otherwise be due (based on the regional schedule set forth in Appendix D). That filing should explain why the seller meets the Category 1 criteria and should include a list of all generation assets (including nameplate or seasonal capacity amounts) owned or controlled by the seller and its affiliates grouped by balancing authority area. Thus, a seller that previously qualified for the § 35.27 exemption and that believes it qualifies as a Category 1 seller would be required to provide support for its claim to Category 1 status. This filing will give the Commission and interested parties an opportunity to review and, if appropriate, challenge a seller's claim that it qualifies as a Category 1 seller. To the extent that an intervenor has concerns about a seller's potential to exercise market power, the Commission will entertain them at that time.[324] In addition, a seller that previously qualified for the § 35.27 exemption and that believes it qualifies as a Category 2 seller will be required to file an updated market power analysis based on the regional schedule set forth in Appendix D.

334. While it is true that a portion of these sellers will continue to sell at market-based rates for a time until their updated market power analyses (in the case of Category 2 sellers) or their filings addressing qualification as Category 1 sellers are due, no commenter has submitted compelling evidence that Category 1 sellers have unmitigated market power. We will rely on our change in status requirements that require, among other things, all sellers that obtain or acquire a net increase of 100 MW in owned or controlled generation to make a filing with the Commission and to provide the effect, if any, such an increase in generation has on the indicative screens. Additionally, all sellers must file EQRs of transactions no later than 30 days after the end of each reporting quarter. Furthermore, the Commission retains the ability to require an updated market power analysis from any seller at any time. With these procedures in place, we believe NASUCA's concerns are addressed.

c. Creation of a Safe Harbor

Comments

335. NRG urges the Commission to create a ''safe harbor'' such that ''if the generation owner controls less than 20 percent of the capacity in an organized market, the Commission should irrebuttably presume that the new entry will not contribute to market power and thus no demonstration is required to obtain market-based rate authority for the new capacity.'' [325] NRG states that

[320] *See* Order No. 888–A, FERC Stats.& Regs. Regulations Preambles July 1996–December 2000 ¶ 31,048 at 30,188 (''[T]he policy eliminates the [generation dominance] showing only as a matter of routine in each filing.'')

[321] *PJM, 110 FERC ¶ 61,053* at P 59.

[322] *PJM II, 112 FERC ¶ 61,031* at P 38.

[323] Nevertheless, the Commission stated that the units would still be subject to mitigation if PJM or its market monitor concluded that they exercised significant market power. *Id.* at P 60.

[324] Moreover, if specific concerns regarding market power exist, interested persons may file a complaint pursuant to FPA section 206.

[325] NRG at 5 & n.8, suggesting that the use of a 20 percent market share in the safe harbor proposal replicates one of the two screens that the

only where an owner controls more than 20 percent of capacity in a relevant market should the presumption be rebuttable and subject to challenge by intervening parties. It is NRG's contention that the creation of such a ''safe harbor'' retains most of the benefits of the Commission's current policy under § 35.27(a), while preserving its flexibility to investigate where a seller adding generating capacity already has a large market share. NRG believes that this codifies the general approach the Commission took in Order No. 888 [326] and responds to the Commission's evolving concerns in this area, while at the same time facilitating new entry in the organized markets where sufficient safeguards exist.[327] NRG contends that new generation, timely developed and brought online, is imperative; thus, a ''safe harbor'' for new generation is necessary.

336. Ameren agrees that there is a need for the Commission to address the § 35.27 exemption before it encompasses all generating capacity; however, Ameren submits that the Commission should allow an exemption for new generation under certain circumstances. Ameren argues that ''the Commission should amend its regulations to provide that new generation that represents less than 20 percent of the uncommitted capacity at peak in the relevant geographic market be exempt from the requirement of a horizontal market power analysis, so long as the owner of, or entity that controls, such capacity and its affiliates own no other generation or transmission facilities (other than interconnection facilities) in the relevant market.'' [328] Ameren submits that the Commission should allow the seller to file a letter which identifies: (1) The transmission system it is interconnected to; (2) the amount of uncommitted capacity it controls; and (3) the Commission-approved market power study that it relied on to determine that its uncommitted capacity is less than twenty percent of the net uncommitted capacity in the relevant geographic market. Ameren contends that this abbreviated process would reduce a seller's cost of compliance and administrative burdens.[329]

Commission Determination

337. The Commission will not create a safe harbor.[330] For the reasons set forth in the April 14 Order and reiterated in the July 8 Order, there will be no safe harbor exemption from the generation market power screen based upon a seller's size.[331] While there is no safe harbor exemption from the screens based on the seller's size, any seller, regardless of size, has the option of making simplifying assumptions in its analysis where appropriate that do not affect the underlying methodology utilized by these screens.

338. Further, while we eliminate the § 35.27 exemption in this Final Rule, we note that sellers that have enjoyed that exemption historically have been required to address the other parts of the market-based rate analysis, vertical market power, affiliate abuse, and other barriers to entry.[332] Therefore, the Commission believes that, on balance, any additional cost of compliance or administrative burden due to this change will not be substantial compared to a seller's investment and revenues.[333]

11. Nameplate Capacity

Commission Proposal

339. In the NOPR, the Commission proposed to allow sellers the option of using seasonal capacity instead of nameplate capacity, as is currently required. The Commission indicated that the seller must be consistent in its choice and thus must choose either seasonal or nameplate capacity and use it consistently throughout the analysis. The Commission stated that it believed the use of seasonal capacity ratings more accurately reflects the seasonal real power capability and is not inconsistent with industry standards and, therefore, it may be more convenient for sellers to acquire and compile the associated data. The Commission added that it did not think the use of such ratings will materially impact results. The Commission sought comment on this proposal, including comment as to whether this information is publicly available to all market participants.

Comments

340. Many commenters on this topic express strong support for the proposal to substitute seasonal capacity for nameplate capacity.[334] The reason most commonly cited is that seasonal capacity is a more accurate representation of actual output. Several commenters state that firms should be allowed to use net seasonal capacity,[335] which allows for station service requirements and energy consumed by environmental equipment. MidAmerican points out that station usage, including environmental equipment, can approach 10 percent of overall output in steam plants.[336] EEI states that coal plants, which make up 51 percent of generation in the United States, are required to comply with both Federal and State regulations that mandate emission reductions. The plants are equipped with scrubbers and other emissions reduction technology that require a portion of the power produced by the plant in order to operate, thereby reducing the output available to serve customers. For companies with a large percentage of their generation coming from coal, the reduced output from such equipment could be significant.[337] PG&E favors using seasonal capacity if it could be filed confidentially, because it maintains that it is commercially sensitive information.[338]

341. PG&E requests clarification that if sellers are allowed to submit seasonal capacity, they are allowed to de-rate

Commission proposes in the NOPR to use as a general screen for market power in all markets reviewed for market-based rate authority. NRG argues that a 20 percent market share screen is well-established and appropriate for use in reviewing the market power implications associated with the addition of new generation. The use of a lightened, single screen approach to review the market power implications of new generation is appropriate, argues NRG, in that new generation expands the supply available in a market. According to NRG, for organized markets administered by RTOs that have in place Commission-approved market monitoring and mitigation authority, subjecting new generation only to a 20 percent market share screen is appropriate in light of the existing controls over the exercise of market power.

[326] *Id.* at n.9, citing Order No. 888, FERC Stats. & Regs., Regulations Preambles, January 1991—June 1996 ¶ 31,036 at 31,657.

[327] *Id.* at n.10. Under NRG's proposal, the Commission would also need to apply the safe harbor analysis to the notice of change of status for the suppliers' existing generation, when the notice of change is triggered by the addition of new generation capacity. Failure to do so would mean the lightened review appropriate for new generation would not, in effect, produce the intended lessening of regulatory burden.

[328] Ameren at 7–8.

[329] *Id.*

[330] We note that although Category 1 sellers are not required to provide a regularly scheduled updated market analysis, such an approach does not establish a safe harbor because all sellers will be required to perform the indicative screens as part of their initial applications, make change in status filings and file EQRs.

[331] *See* April 14 Order, 107 FERC ¶ 61,018 at P 69, 117; July 8 Order, 108 FERC 61,026 at P 107 (the Commission explained that small sellers are able to use simplifying assumptions).

[332] As described in this Final Rule, we consolidate the transmission market power and other barriers to entry analyses into one vertical market power analysis. In addition, we discontinue considering affiliate abuse as a separate part of the analysis and instead codify affiliate restrictions in our regulations.

[333] NOPR at P 71.

[334] Duke at 22; First Energy at 10; Southern at 26; SoCal Edison at 8.

[335] EEI at 18; PNM/Tucson at 10; Allegheny at 7–8; Pinnacle West at 5–6; PPL at 17.

[336] MidAmerican at 8.

[337] EEI at 18.

[338] PG&E at 10–11.

hydroelectric capacity resources based on historical output for the past five years, as specified in the April 14 Order.[339] Powerex supports seasonal ratings as more accurate, because hydroelectric systems are often able to generate in excess of nameplate ratings and these ''peak capability'' ratings are typically reflected in seasonal determinations, and seasonal ratings better reflect operating conditions that can impact the capacity ratings of renewable resources.[340]

342. APPA/TAPS support the adoption of seasonal capacity ratings if they are consistently used, and request that the Commission clarify that the seasonal capacity ratings be used for all plants in a geographic region ''so that the consistency benefits of the regional reviews are not diminished.'' [341]

Commission Determination

343. We will adopt the NOPR proposal that allows sellers to use seasonal capacity. We clarify that each seller must be consistent in its choice and thus must choose either seasonal or nameplate capacity and use it consistently throughout the analysis. In addition, a seller using seasonal capacity must identify in its submittal from what source the data was obtained.[342] We also note and adopt the Energy Information Administration (EIA) definition of seasonal capacity as it is reported on Form EIA–860, Schedule 3, Part B, Line 2, which provides that seasonal capacity is the ''net summer or winter capacity.'' [343] EIA instructions elaborate that ''net capacity should reflect a reduction in capacity due to electricity use for station service or auxiliaries,'' [344] which includes scrubbers and other environmental devices.

344. With regard to energy-limited resources, such as hydroelectric and wind capacity, in lieu of using nameplate or seasonal capacity in their submissions, we will allow such resources to provide an analysis based on historical capacity factors reflecting the use of a five-year average capacity factor including a sensitivity test using the lowest capacity factor in the previous five years, and in recognition of Powerex's concern that hydroelectric systems can generate in excess of nameplate ratings and these ''peak capability'' ratings, the highest capacity factor in the previous five years. Our approach in this regard will more accurately capture hydroelectric or wind availability.[345]

345. We will not adopt APPA/TAPS' suggestion that we require use of either nameplate capacity or seasonal capacity throughout a region. While we appreciate APPA/TAPS' concern for data consistency for analysis purposes, we note that although we adopt a regional approach for the filing of updated market power analyses, the horizontal market power analysis itself continues to focus on the seller seeking to obtain or retain market-based rate authority. We find that consistency of data is critical within each individual analysis as results could vary depending on the assumptions taken. However, because we are not necessarily analyzing the entire region within a single study, we will not mandate the use of either nameplate capacity or seasonal capacity on a regional basis, but instead will allow sellers to choose either nameplate or seasonal capacity, and require them to identify the choice and use it consistently throughout the analysis.[346]

12. Transmission Imports

346. In the NOPR, the Commission proposed to continue to measure limits on the amount of capacity that can be imported into a relevant market based on the results of a simultaneous transmission import capability study. A seller that owns, operates or controls transmission is required to conduct simultaneous transmission import capability studies for its home control area and each of its directly-interconnected first-tier control areas consistent with the requirements set forth in the April 14 Order, as clarified in Pinnacle West Capital Corp.[347] These studies are used in the pivotal supplier screen, market share screen, and DPT to approximate the transmission import capability. When centering the generation market power analysis on the transmission providing utility's first-tier control area (*i.e.*, markets), the transmission-providing seller should use the methodologies consistent with its implementation of its Commission-approved OATT, thereby making a reasonable approximation of simultaneous import capability that would have been available to suppliers in surrounding first-tier markets during each seasonal peak. The transfer capability should also include any other limits (such as stability, voltage, Capacity Benefit Margin, or Transmission Reliability Margin) as defined in the tariff and that existed during each seasonal peak. The ''contingency'' model should use the same assumptions used historically by the transmission provider in approximating its control area import capability.

347. The Commission also proposed to reaffirm the exclusion of control areas that are second-tier to the control area being studied. In addition, it proposed that a seller's *pro rata* share of simultaneous transmission import capability should be allocated between the seller and its competitors based on uncommitted capacity. The Commission sought comment on this proposal.

a. Use of Historical Conditions and OASIS Practices

Comments

348. Montana Counsel states that transmission capability used in the tests should not be greater than the capability measures that are shown on the OASIS or that are used to measure ATC into markets unless there is a demonstrated change in available transmission capability.[348] In particular, Montana Counsel states that the Commission's requirement that sellers follow historical OASIS practice during each historical seasonal peak is essential; otherwise, companies could submit screens using transmission availability numbers that differ substantially from those which sellers and transmission

[339] April 14 Order, 108 FERC ¶ 61,018 at P 126. The July 8 Order allowed this method to be used for wind resources as well. July 8 Order, 108 FERC ¶ 61,026 at P 129.

[340] Powerex at 20.

[341] APPA/TAPS at 35.

[342] In the July 8 Order, the Commission stated that ''[w]ith respect to data that is only available from commercial sources, we clarify that commercial sources may be used to the extent the data is made available to intervenors and other interested parties. Applicants utilizing commercial information to perform the screens should include it in their filing.'' July 8 Order, 108 FERC ¶ 61,026 at P 121.

[343] EIA–860 Instructions are available at *http://www.eia.doe.gov/cneaf/electricity/forms/eia860/eia860.pdf*.

[344] Tip Sheet for Reporting on Form EIA–860, ''Annual Electric Generator Report'' at item ''III. Schedule 3B, Line 2 and Schedule 3D, Line 2: Net Capacity'' available at *http://www.eia.doe.gov/cneaf/electricity/forms/eia860/tipsheet.doc*.

[345] In the April 14 Order, we explained that commenters expressed concerns regarding the appropriate measure of the capacity of hydroelectric units given that hydroelectric facilities are energy-limited units. Our experience with Western markets shows that market outcomes can be significantly different during low water years. We agree with the comments raised by Western market participants and conclude that properly accounting for water availability will provide a better picture of competitive conditions in the West. Moreover, while not as critical in other parts of the country as in the West, the same principle regarding water availability applies to all electricity markets, and we will permit all sellers to de-rate hydroelectric capacity in the analysis.

[346] When submitting a change in status filing regarding horizontal market power, sellers should use the same assumptions they used (*e.g.*, use of nameplate or seasonal ratings) in their most recent market power analysis.

[347] 110 FERC ¶ 61,127 (2005).

[348] Montana Counsel at 4.

providers use in day-to-day activities in providing transmission market access.[349] In Montana Counsel's view, one cannot rely on capacity being able to reach a market based upon hypothetical transmission availability, as the Commission appropriately recognizes.

349. In response to Montana Counsel's assertion to use OASIS postings, PPL Companies maintain that the Commission should continue to use simultaneous import limit studies. OASIS postings do not adjust for transmission rights controlled by unaffiliated resources that may be used to compete against the seller in wholesale markets. PPL Companies state: ''The Commission should reject this proposal and continue to rely on [SILs]. The Commission properly has found that using actual OASIS postings understates import capability because OASIS postings do not take into account the capacity that may be imported as a result of existing reservations.''[350]

350. EEI and Southern request clarification of a perceived conflict in Appendix E, which instructs sellers to use Commission criteria for calculating simultaneous import capability and also to strictly follow their OASIS practices.[351] They recommend that the Commission clarify that if historical practices are different from Appendix E, historical practices should be used to calculate simultaneous transmission import capability and to allocate this transmission capability.

351. Duke asserts that scaling methods for calculating simultaneous transmission import capability should not be solely limited to historical practices used by the seller to post ATC on OASIS. Duke proposes a collaborative method involving the seller and transmission customers. Duke states: ''the Commission should allow applicants flexibility to use the appropriate methodology for SIL determinations including collaborative, regional efforts—so that screen results for control area markets can be accurate. For example, the Commission should not be overly prescriptive as to the scaling methodology to be used in such a collaborative effort, as long as the methodology is clearly defined and supported by the applicants.''[352] PPL Companies support the collaborative effort proposed by Duke, stating that sellers should have ''the option of proposing alternative [SILs] for first-tier markets, but would have to justify and document the proposed deviations.''[353]

352. Southern states that the SIL study requires ''blind'' scaling (scaling that does not consider economic dispatch) because only generation that is ''on-line'' is used. Southern states that to the extent a transmission provider does not customarily employ blind scaling, its use would not be consistent with historical practice. It asserts that a problem with blind scaling is that it does not necessarily reflect reality and therefore has the potential to understate, perhaps significantly, the simultaneous import limit.[354] EEI seeks clarification that the Commission is not requiring blind scaling in a manner that requires proportionate increases and decreases to generation resources. EEI requests clarification that scaling is allowed to include expert judgment reflecting how generation resources would likely be scaled up or down in a real-time operating environment. EEI contends that expert judgment in some cases may determine simultaneous import capability by scaling load rather than generation resources. EEI requests that the Commission defer to expert judgment in scaling and not be overly prescriptive as to whether generation or load is scaled to determine simultaneous import capability.[355]

353. PPL Companies contend the simultaneous import capability should not be limited by load in a control area. Since generators within the control area may sell power within or outside the control area, the Commission should consider the market prices of surrounding regions. If the prices are 105 percent or less, compared to control area prices, then the Commission should assume the resident control area resources will remain within the control area and not result in economic withholding within the seller's area.[356]

Commission Determination

354. The Commission will continue to require sellers to submit the Appendix E analysis, *i.e.*, the SIL study, to calculate aggregated simultaneous transfer capability into the balancing authority area being studied.[357] The Commission reaffirms that the SIL study is ''intended to provide a reasonable simulation of historical conditions''[358] and is not ''a theoretical maximum import capability or best import case scenario.''[359] To determine the amount of transfer capability under the SIL study, ''historical operating conditions and practices of the applicable transmission provider (*e.g.*, modeling the system in a reliable and economic fashion as it would have been operated in real time) are reflected.''[360] In addition, the ''analysis should not deviate from'' and ''must reasonably reflect'' its OASIS operating practices[361] and ''the techniques used must have been historically available to customers.''[362] We also reaffirm that the power flow cases (which are used as inputs to the SIL study) should represent the transmission provider's tariff provisions and firm/network reservations held by seller/affiliate resources during the most recent seasonal peaks.[363]

355. The Commission will also continue to allow sensitivity studies, but the sensitivity studies must be filed in addition to, and not in lieu of, an SIL study. We clarify that sensitivity studies are intended to provide the seller with the ability to modify inputs to the SIL study such as generation dispatch, demand scaling, the addition of new transmission and generation facilities

[349] *Id.* at 14.

[350] PPL Companies reply comments at 9–11.

[351] EEI at 27–29; Southern at 32.

[352] Duke at 27–28.

[353] PPL Companies reply comments at 9–11

[354] Southern at 35 and 36.

[355] EEI at 24.

[356] PPL Companies at 8.

[357] Benefits of using a uniform transmission import model include: Transparency, consistency, clarity, and reasonable assurance that system conditions have been adequately captured.

[358] In this regard, actual flows during the study periods may be used as a proxy for the simultaneous transmission import limit.

[359] NOPR at P 77.

[360] *Id.*

[361] By OASIS practices, we mean sellers shall use the same OASIS methods and studies used historically by sellers (in determining simultaneous operational limits on all transmission lines and monitored facilities) to estimate import limits from aggregated first-tier control areas into the study area. In this sense, sellers are modeling first-tier balancing authority areas as if they are the transmission operator/security coordinator (monitoring reliability) operating an OASIS for the aggregated first-tier footprint. We recognize that sellers are not the balancing authority area operators of first-tier balancing authority areas and in some instances, sellers may not be familiar with all aspects of their first-tier balancing authority areas' transmission system limits. However, sellers should be familiar with major constraints, path limits, and delivery problems in these neighboring transmission systems. If a seller participates in regional planning studies and day-to-day coordination with neighboring first-tier balancing authority areas then this will provide a reasonable basis for including transmission system constraints of first-tier balancing authority areas in SIL study calculations. In using OASIS practices the SIL study shall capture real-life physical limitations of first-tier balancing authority areas that impede power flowing from remote first-tier resources into the seller's study.

[362] *Id.* at P 77, 78.

[363] Network reservations include any grandfathered transmission rights applicable to the seller or its affiliated companies.

(and the retirement of facilities), major outages, and demand response.[364]

356. The Commission agrees with Montana Counsel and clarifies for PPL Companies that a SIL study must reflect transmission capability no greater than the capability measures that were historically shown on the OASIS or that were historically used to measure transmission capability into markets unless there is a demonstrated change in transmission capability, and account for the actual practice of posting ATC to OASIS in order to capture a realistic approximation of first-tier generation access to the seller's market. Further, and in response to EEI and Southern's comments, the Commission clarifies that when actual OASIS practices conflict with the instructions of Appendix E, sellers should follow OASIS practices and must provide adequate support in the form of documentation of these processes.

357. We disagree with Duke's argument that a seller's (generation or load) scaling methods should not be limited to historical OASIS practices when conducting an SIL. Using historical practices provides an appropriate method to obtain a transparent and measurable analysis of a seller's actual balancing authority area transmission conditions and practices. Improper or theoretical scaling methods which do not represent a seller's actual transmission practices may have the effect of allowing more competing generation into the balancing authority area than could actually be accommodated. This in turn has the effect of reducing a seller's generation market share and perhaps causing the seller to inappropriately pass the market share screen (a false negative).[365] In addition, relying on historical OASIS practices gives a seller the data needed to support its conclusions.

358. With regard to Duke and PPL's request that the Commission allow sellers to submit a flexible SIL study based on regional collaboration, the Commission finds that such an approach does not satisfy our concerns and may result in an unrealistic representation of the market.

359. Southern states that to the extent a transmission provider does not customarily employ blind scaling, its use would not be consistent with historical practice.

We agree and, as noted herein, the horizontal analysis and the SIL study are designed to study historical and realistic conditions during peak seasons. Accordingly, in this circumstance, sellers should follow their OASIS practices and must provide adequate support in the form of documentation of these processes.

360. With regard to EEI's argument that the Commission should consider allowing expert judgment in predicting real-time scaling techniques that will likely be used in real-time market environments, the Commission requires the use of a study that captures historical transmission operating practices. The SIL study is not a prediction of import possibilities; rather, it is a simulation of historical conditions. We assume that such historical conditions are the result of ''expert judgment'' used when determining generation dispatch and/or scaling techniques to make transmission capacity available during actual system conditions. Accordingly, this expert judgment is captured when conducting an SIL study that is based on historical operating practices.

361. In response to PPL's comments that the SIL should not be limited by load in a balancing authority area, the Commission reiterates that the SIL study is a benchmark of historical conditions, including peak load. It is a study to determine how much competitive supply from remote resources can serve load in the study area. Increasing the load in the study area beyond historical peak levels makes the study less realistic and can bias the study.[366] The Commission does, however, consider sensitivity studies on a case-by-case basis, when submitted in addition to the SIL study and supported by record evidence. For example, in Puget Sound Energy, Inc.'s (Puget) updated market power analysis filing, Puget demonstrated that the simultaneous transmission import limit was greater than the peak load in its balancing authority area, and the Commission allowed Puget to use a simultaneous transmission import limit based on its peak load.[367]

362. PPL also contends the simultaneous import capability should not be limited by load in a balancing authority area since generators within the balancing authority area may sell power within or outside the balancing authority area. Accordingly, PPL believes that the Commission should consider the market prices of surrounding regions. The Commission disagrees. We base the SIL on historical conditions that actually existed during the study periods. In this regard, PPL has provided no compelling reason for the Commission to abandon historical evidence in favor of a theoretical estimation of what could have occurred. We find that PPL's approach would make the studies more subjective and thus less accurate and more prone to dispute and controversy.

b. Use of Total Transfer Capability (TTC)

Comments

363. Southern asserts that the Commission's assumption that all TTC values posted on OASIS platforms are non-simultaneous is not correct. Southern states that although many TTC values may be calculated on a point-to-point non-simultaneous basis, some TTC values are simultaneous, thus accounting for ''loop flow'' created by other paths. Southern contends that those transmission providers that post simultaneous TTC values on OASIS should have the flexibility to add these TTC values to calculate simultaneous transmission import capability for the control area. Southern believes that conflicts can occur between the generic methods presented in the Appendix E interim market screen order and actual OASIS practices used by transmission providers to post TTC.

Commission Determination

364. Southern's suggestion that the Commission allow the use of simultaneous TTC values is consistent with the SIL study provided that these TTCs are the values that are used in operating the transmission system and posting availability on OASIS. The simultaneous TTCs[368] must represent more than interface constraints at the balancing authority area border and must reflect all transmission limitations within the study area and limitations within first-tier areas. The source (first-tier remote resources) can only deliver power to load in the seller's balancing authority area if adequate transmission is available out of its first-tier area, adequate transmission is available at the seller's balancing authority area

[364] We note that several sellers from the Western Interconnection have relied on Western Electricity Coordinating Council (WECC) path ratings for their SIL studies. The Commission has accepted these ratings when sellers have demonstrated that they are simultaneously feasible and take into account any interdependencies between paths.

[365] *See, e.g., Pinnacle West Capital Corp.,* 117 FERC ¶ 61,316 (2006).

[366] We note that there may be a circumstance where additional supplies could be imported above the market's study year peak load. If such a circumstance occurs, we will allow the seller to submit a sensitivity analysis in this regard and we will consider such an analysis on a case-by-case basis.

[367] *Puget Sound Energy, Inc.,* 111 FERC ¶ 61,020 at P 13 (2005).

[368] The simultaneous TTCs include seller's balancing authority area and aggregated first-tier areas.

interface, and transmission is internally available. Thus, the TTC must be appropriately adjusted for all applicable (as discussed below) firm transmission commitments held by affiliated companies that represent transfer capability not available to first-tier supply. Sellers submitting simultaneous TTC values must provide evidence that these values account for simultaneity, account for all internal transmission limitations, account for all external transmission limitations existing in first-tier areas, account for all transmission reliability margins, and are used in operating the transmission system and posting availability on OASIS.

c. Accounting for Transmission Reservations

Comments

365. Duke and EEI propose that short-term firm reservations should not be subtracted from simultaneous import limits because longer firm reservation requests can displace control of these transmission holdings.[369] EEI explains, ''it is inappropriate to net out transmission capacity that is not reserved to commit long-term generation resources to load. Short-term firm transmission reservations, some as short as one week in duration, provide flexibility to the market and will not necessarily persist for the duration, or even large portions, of the MBR authorization period. Therefore, they should not be used to reduce the estimate of simultaneous import capability.''[370]

366. Southern agrees, referring to the nature of short-term reservations as ''transient and unpredictable.'' [371] Southern states: ''In most cases, short-term purchases by the applicant essentially allow the market to provide generation within the applicant's control area instead of the applicant utilizing its 'owned' generation capacity. Alternatively, the associated import capability is released to the market. In either case, these short-term reservations should not be used to inflate artificially the applicant's market share in conjunction with a screen or DPT evaluation.'' [372]

367. APPA/TAPS state that the Commission should revisit the treatment of firm transmission reservations held by third parties. In the July 8 Rehearing Order (at P 49), the Commission stated that the SIL study assumed that ''all reservations historically controlled by non-affiliates would have been used to compete to inject energy into the transmission provider's control area market if market power or scarcity was driving market prices above other regional prices.'' However, if the holder of the reservation is using the transfer capability to serve its own load, it will not be available to third parties to respond to a price increase on the part of the transmission provider/sellers. APPA/TAPS state that presumably the capacity resources associated with the import will be reflected in the capacity total of the party that controls the resource's output. Excluding the transfer capability associated with the resource will not result in a double-deduction. Rather, failing to exclude the transfer capability will result in a double-counting of competing supply. Thus, APPA/TAPS assert that the Commission should revise the treatment of transfer capability held by third parties on a firm basis.[373]

Commission Determination

368. The Commission agrees with Duke, EEI and Southern that short-term firm reservations can be unpredictable, driven by real time system conditions, and do not necessarily indicate that the associated transmission capacity is not available for competing supplies (or to import seller's supplies during the study periods). Accordingly, we conclude that, in calculating simultaneous transmission import limits, short-term firm reservations of 28 days or less in effect during the study periods need not be accounted for.[374] While we find that firm transmission reservations less than or equal to 28 days in duration are usually unpredictable, we believe that firm transmission reservations of a longer duration are not related to the unpredictable nature of real time events and are based upon planned and predictable events. Therefore, the Commission will require sellers to account for firm and network transmission reservations having a duration of longer than 28 days.[375]

369. With regard to APPA/TAPSs' concern, we clarify that the seller's firm, network, and grandfathered transmission reservations longer than 28 days, including reservations for designated resources to serve retail load, shall be fully accounted for in the simultaneous import limit study. We further clarify that reservations held by third parties to import power into the seller's home area should be accounted for by allocating transmission import capability to those parties, and then allocating the remaining SIL pro rata.

d. Allocation of Transmission Imports Based on Pro Rata Shares of Seller's Uncommitted Generation Capacity

Comments

370. Duke and EEI support the Commission proposal to allocate imports on a pro rata basis into a study area based on uncommitted capacity in surrounding areas.[376]

371. However, Powerex expresses concern that pro rata allocation of uncommitted capacity is not a realistic representation of the physical capability of the system, since *pro rata* allocation assumes that the system can import up to the simultaneous import limit over any combination of transmission paths. Powerex argues that, in reality, some paths become constrained before others, so the allocation of import capability should take account of the physical limitations of the transmission system. Powerex asks that the Commission allow sellers to use allocation methods that are consistent with physical system limitations, where sellers provide documentation showing that the allocation methods used in the screens are realistic or conservative.[377]

372. Morgan Stanley asks the Commission to clarify its proposal of allocating transmission imports *pro rata* between the seller and its competitors based on uncommitted capacity. Morgan Stanley wonders if the Commission made a typographical error and intended to propose an allocation based on committed capacity. Morgan Stanley believes only the transmission provider (seller) would have uncommitted capacity.[378]

Commission Determination

373. The Commission agrees with Duke and EEI that the current practice of allocating simultaneous import

[369] Duke at 26–29.

[370] EEI at 25–26.

[371] Southern at 36–37.

[372] *Id.* at 37.

[373] APPA/TAPS at 53.

[374] We understand that short-term firm reservations are often used for unpredictable events and real-time system conditions. We note that most unpredictable conditions that sellers hold short-term firm reservations for, including generator forced outages and weather events, are less than one month in duration. Accordingly, we will allow applicants to not account for short-term firm reservations of one month or less, and since the shortest month is 28 days long, we are setting this limit at 28 days. Any firm reservation longer than 28 days in duration must continue to be accounted for in the SIL study.

[375] The simultaneous import limit study must account for short-term firm transmission rights including point-to-point on-peak/off-peak transmission reservations (firm or network transmission commitments) which have been stacked, or successively arranged, into an aggregated point-to-point transmission reservation longer than 28 days.

[376] Duke at 26–29, EEI at 25–26.

[377] Powerex at 24–25.

[378] Morgan Stanley at 15.

capability *pro rata* to sellers based on uncommitted capacity should be continued.[379] However, some clarification may be helpful.

374. Powerex raises concern over the *pro rata* allocation of uncommitted generation capacity and asserts that this is not a realistic representation of the physical capability of the system since *pro rata* allocation assumes that the system can import up to the simultaneous import limit over any combination of transmission paths. In this regard, we note that *pro rata* allocation of transmission capacity based on first-tier uncommitted generation capacity is an approximation and is consistent with the manner in which we conduct the SIL study. In particular, when determining the simultaneous import limit, first-tier balancing authority areas are combined into a single area. The import capability of the study area is the simultaneous transfer limit from the aggregated first-tier market area into the study area.[380] We then allocate imports based on transmission capacity (limited by the physical capabilities of the transmission system as determined by the SIL study) *pro rata* based on sellers' first-tier uncommitted generation capacity.[381] We recognize that such an approximation may not fit all cases. Accordingly, with regard to allocating transmission imports, sellers can submit additional sensitivity studies based on factors suggested by Powerex, and intervenors may rebut the allocations of import capability made by seller. The Commission will consider such arguments on a case-by-case basis.

375. Morgan Stanley asks if the Commission made a typographical error and intended to propose an allocation based on committed capacity rather than uncommitted capacity. The Commission clarifies that *pro rata* allocation is used to assign shares of simultaneous transmission import capability to uncommitted generation capacity in the aggregated first-tier balancing authority areas to determine how much uncommitted generation capacity can enter the study area. Morgan Stanley appears to confuse our use of the term uncommitted capacity, apparently believing we are referring to uncommitted transmission capacity. That is not the case as we are referring to uncommitted generation capacity. The reason the use of uncommitted generation capacity is appropriate is because our screens analyze seller's relative uncommitted generation capacity rather than installed generation capacity or, as suggested by Morgan Stanley, committed generation capacity. In particular, the SIL study determines the amount of simultaneous transmission capacity available to be imported by competing supplies from remote resources in first-tier markets. The supplies that are available to be imported and thus compete are necessarily ''uncommitted.'' Further, it is our experience that uncommitted generation capacity can be held by any number of market participants based on market conditions at a given time. In other words, we do not agree with an assumption that the transmission provider is likely to be the only market participant with uncommitted power supplies.

e. Miscellaneous Comments

Comments

376. PG&E states that RTOs/ISOs having knowledge and control over the entire control area are best suited to perform SIL studies. PG&E requests that the Commission allow an exemption where, in the absence of an accepted SIL study by an RTO/ISO, the seller may substitute historical import levels in place of the SIL study. In addition, PG&E requests that the Commission confirm that sellers that pass screens for each relevant geographic market without considering imports need not provide a simultaneous import analysis.[382]

377. Powerex has concerns about how feasible it is for marketers to obtain non-public data from their transmission provider that is needed to conduct a screen (*e.g.*, a SIL study) on their own. Powerex notes that Bonneville Power Administration (BPA) and Northwest Power Pool (NWPP) do not, as a practice, conduct and post simultaneous transmission import capability studies. Therefore, Powerex asserts that the Commission should maintain the current flexibility of allowing marketers to submit credible proxy study calculations based on publicly available information.[383]

Commission Determination

378. The Commission will continue to require the SIL study for the indicative screens and DPTs in order to assure that restrictions regarding importing first-tier supply are captured for seasonal peak conditions. Benefits of using a uniform transmission import model include: Transparency, consistency, clarity, and reasonable assurance that system conditions have been adequately captured. As also stated above, the Commission provides sellers flexibility to provide sensitivity analyses by modifying inputs to the SIL study.

379. In regard to PG&E's belief that RTOs/ISOs are best equipped to conduct SIL calculations, the Commission will continue to require transmission-providing sellers to perform the SIL studies as necessary. To the extent that an RTO/ISO conducts transmission studies and makes that information available, a seller may rely on the information obtained from its RTO/ISO to conduct its SIL study. Further, the Commission clarifies that to the extent the transmission-owning seller can demonstrate it passes the screens for each relevant geographic market without considering imports, it need not submit a SIL study.[384]

380. Powerex requests that it be able to submit proxies in place of a SIL study. The Commission notes that transmission-providing sellers are required to be the first to file SIL studies, which makes the required data available to non-transmission owning sellers for use in performing their generation market power analyses.[385] However, as the Commission stated in the April 14 Order,

> an applicant may provide a streamlined application to show that it passes our screens. Thus, with respect to simultaneous import capability, if an applicant can show that it passes our screens for each relevant geographic market without considering imports, no such simultaneous import analysis needs to be provided. Further, we recognize that certain applicants will not have the ability to perform a simultaneous import capability study. Accordingly, if an applicant demonstrates that it is unable to perform a simultaneous import study for the control area in which it is located, the applicant may propose to use a proxy amount for transmission limits. We will consider such proposals on a case-by-case basis.[386]

381. In this regard, we note that we have accepted proxy amounts for

[379] Allocation of the simultaneous transmission import capability, into the seller's market, to affiliated and unaffiliated uncommitted first-tier generation is done in the indicative screen, after conducting the SIL study, in order to estimate uncommitted capacity market shares from first-tier balancing authority areas.

[380] April 14 Order, 107 FERC ¶61,018 at Appendix E.

[381] The SIL study also accounts for transmission reservations when determining the amount of imports available to reach the study area as discussed herein and in the April 14 and July 8 Orders.

[382] PG&E at 11–12. PG&E also requests that the Commission clarify how to perform the simultaneous import limitation to avoid the need for repetitive studies. However, PG&E did not specify what clarification was sought in this regard.

[383] Powerex at 5–25.

[384] April 14 Order, 107 FERC ¶ 61,018 at P 85.

[385] July 8 Order, 108 FERC ¶ 61,026 at 46.

[386] April 14 Order, 107 FERC ¶ 61,018 at P 85.

transmission limits and will continue to consider such requests on a case-by-case basis.[387]

f. Required SIL Study for DPT Analysis

Comments

382. EEI and Southern propose that the Commission not mandate SIL studies as the only method for calculating import limits for DPT analysis. EEI states that while such a study may be an appropriate tool for indicative screens, the DPT is a more comprehensive study and the Commission should allow for more precise, non-standardized approaches for calculating simultaneous import capability for use in the DPT.[388] Southern states that the apparent purpose of Appendix E is to provide a somewhat standardized approach to assessing simultaneous import capability that goes hand-in-hand with the simplified tools used to develop a preliminary assessment of generation market power. It argues that where a seller presents a more thorough generation analysis pursuant to a DPT, it should be permitted to offer a more thorough analysis of transmission import capability.[389]

383. NRECA responds that the Commission should not allow sellers to substitute alternative measures of simultaneous import capability in the DPT. NRECA states that while a seller should be allowed to conduct a SIL study that is more refined than the one required of all sellers, ''the applicant's alternative analysis should be submitted in addition to, and not in lieu of, the required analysis'' in the DPT.[390] It argues that otherwise, each seller will do the analysis a bit differently so that the analysis will favor passing the tests. According to NRECA, the worst-case scenario is that there will be no standardized approach, which would exacerbate the existing problems created by inadequate access to the data underlying the sellers' market power analysis and the lack of standard reporting and increase the burdens on intervenors and the Commission staff in evaluating applications for market-based rates and market power updates. NRECA states that one advantage of requiring all sellers to use a standard analysis, in addition to whatever other analysis they may choose to offer, is that it can more effectively bring to light the problems now hidden from view in the seller's historical practices, resulting in increased transparency.

Commission Determination

384. For the reasons stated herein regarding the need to as accurately as possible account for transmission limitations when considering power supplies that can be imported into the relevant market under study, the Commission adopts the requirement for use of the SIL study as a basis for transmission access for both the indicative screens and the DPT analysis.

385. The lack of flexibility in creating a simultaneous transmission import limit has been identified by several commenters. However, the Commission believes it has provided sellers sufficient flexibility to adequately represent their process for making transmission available to unaffiliated supply. The Commission shares NRECA's concerns that opening the process to alternative study methods without a specified standard may result in deviations from reasonable depictions of transmission limits historically applied to first-tier suppliers and will likely bias such studies to the benefit of the seller.

386. With regard to the DPT analysis, there are several primary reasons for the continued use of simultaneous transmission import limit studies: Uniformity of modeling affiliated and unaffiliated supply, consideration of simultaneity, consideration of seller and affiliate transmission commitments and reservations, consideration of all internal transmission limitations, consideration of all external transmission limitations existing in first-tier areas, consideration of the seller's (or the seller's transmission provider's) practices for posting ATC, and consideration of peak seasonal conditions. By requiring the SIL study in the DPT analysis, the Commission assures that all factors important in determining transmission access to the seller's market are taken into account.

13. Procedural Issues

Commission Proposal

387. In the NOPR, the Commission noted that Order No. 662[391] addressed concerns that CEII claims in market-based rate filings are overbroad. In Order No. 662, the Commission stated that it is willing to consider on a case-by-case basis requests for extensions of time to prepare protests to market-based rate filings where an intervenor demonstrates that it needs additional time to obtain and analyze CEII. In Order No. 662, the Commission encouraged the parties in cases in which CEII is filed to promptly negotiate a protective order governing access to the CEII, or privately negotiate for the submitter to provide the data to interested parties pursuant to an appropriate non-disclosure agreement. The Commission sought comments in the NOPR on whether CEII designations remain a concern since issuance of Order No. 662.

388. The Commission also sought comments regarding whether the comment period (generally 21 days from the date of filing) provided for parties to file responses to the indicative screens and DPT analyses is sufficient. The Commission asked what would be an appropriate comment period if it were to establish a longer period for submitting comments on indicative screen and DPT analyses.

Comments

389. A number of commenters note that intervenors should be given adequate time to respond to CEII designations. APPA/TAPS suggest that the Commission provide a process to allow interested market participants to obtain CEII authorization in advance of a region's triennial updates. They submit that such authorization would apply to all sellers in the region where market-based rate authority is up for review and would necessitate that the requester file only one request.[392] Montana Counsel states that intervenors should also be given adequate time to respond to confidentiality claims with regard to non-CEII data.[393]

390. A number of commenters support extending the comment period for market-based rate filings. Ameren supports a 30-day comment period on the basis that 30 days has proven to be a sufficient comment period for section 203 filings.[394] Morgan Stanley recommends a 45-to 60-day comment period if the Commission adopts a regional approach for updated market power analyses.[395] NRECA states that under a regional filing process, a 21-day comment period is inadequate when several updated market power analysis filings are reviewed at once, and instead advocates a 90-day comment period from the notice of the filing or from the

[387] *See, e.g., Tampa Electric Co.,* 110 FERC ¶ 61,026 at P 32 (2005) (using the largest ATC into the control area at the time the study is conducted is a conservative assumption for import capability and an acceptable proxy for the SIL study).

[388] EEI at 24–25.

[389] Southern at 4, 37–38.

[390] NRECA reply comments at 24–25.

[391] *Critical Energy Infrastructure Information,* Order No. 662, 70 FR 37031 (June 28, 2005), FERC Stats. & Regs. Regulations Preambles 2001–2005 ¶ 31,189 (June 21, 2005).

[392] APPA/TAPS at 35–36.

[393] Montana Counsel at 23–24.

[394] Ameren at 8.

[395] Morgan Stanley at 14.

date of a completed filing if additional data is requested by the Commission.[396]

Commission Determination

391. In this Final Rule, we adopt procedures under which intervenors in section 205 proceedings may obtain expedited access to CEII or other information for which privileged treatment is sought. A request for access to information for which CEII status or privilege treatment has been claimed generally takes a few weeks for the Commission to process under the standard process found in 18 CFR 388.112 and 388.113.[397] Such a delay in receiving such information may make it difficult for an intervenor to submit timely comments.

392. An expedited process does exist for section 203 filings. Section 33.9 of the Commission's regulations[398] states that a seller seeking to protect any part of its application from public disclosure must also submit a proposed protective order. Parties may sign the proposed protective order and obtain CEII or privileged materials in a more timely manner, without having to spend time negotiating the terms of a protective order or waiting for the Commission to process the request through its standard request process.

393. In order to ensure that intervenors have access in a timely manner to relevant information for which privileged treatment is claimed, we will adopt language similar to § 33.9 in this Final Rule, to be codified at 18 CFR 35.37(f). We intend that the proposed protective order will be self implementing and not require action by the Commission; once a party signs the proposed protective order and returns it to the party submitting protected material, the submitter is expected to provide the material promptly to the requester. We note that the Commission's Model Protective Order is available on the Commission's Internet site and may be used as a guide in preparing proposed protective orders.[399] To expedite processing, the regulation will require that the seller provide the CEII or privileged material to the requester within five days after the protective order is signed and submitted to the seller.

394. With respect to APPA/TAPS's suggestion to make CEII authorization region-wide to coincide with region-wide analysis, we do not believe such a step is necessary or advisable at this time. Our goal with CEII has always been to limit access to those with a legitimate need for the information. We do not expect that all market participants in a region will want to comment on all updated market power analyses within that region. Moreover, we anticipate that our regulatory change requiring submission of a proposed protective order will go a long way to resolving past difficulties in obtaining non-public information in a timely manner.

395. With regard to the comment period for parties to file responses to updated indicative screens, we believe, as we discuss below in the section on Implementation, that extending the comment period for regional updated market power analyses will allow intervenors a better opportunity to review and comment on those filings, especially considering the large number of filings that will be submitted at one time. Hence, we will establish a 60-day comment period for updated market power analyses that are filed in accordance with the schedule in Appendix D.

396. With regard to the comment period for initial applications and for DPT analyses ordered as part of a section 206 proceeding, the Commission will retain the current 21-day comment period. However, we remain willing to consider on a case-by-case basis requests for extensions of time beyond 21 days to submit comments on these filings.

*B. Vertical Market Power*

397. In the NOPR, the Commission proposed to replace the existing four-prong analysis (generation market power, transmission market power, other barriers to entry, affiliate abuse/reciprocal dealing) with an analysis that focuses on horizontal market power and vertical market power. Accordingly, it proposed that issues relating to whether the seller and its affiliates have transmission market power or whether they can erect other barriers to entry be addressed together as part of the vertical market power part of the analysis.

Comments

398. As a general matter, commenters expressed support for the proposed consolidation of the transmission market power and other barriers to entry prong into one vertical market power analysis.[400] According to EPSA, analyzing vertical market dominance in one single prong could be a positive step, provided that the elements of the prong are explicitly specified and effectively enforced.[401] No commenter opposed the Commission's proposal in this regard.

Commission Determination

399. In light of the reasons discussed in the NOPR and the comments received, the Commission will adopt the NOPR proposal to consolidate the transmission market power analysis and other barriers to entry analysis into one vertical market power analysis.

1. Transmission Market Power

Commission Proposal

400. In the NOPR, the Commission noted that it recognized that Order No. 888 did not eliminate all potential to engage in undue discrimination and preference in the provision of transmission service,[402] and that it had issued a Notice of Inquiry and a NOPR regarding whether reforms are necessary to the Order No. 888 *pro forma* OATT.[403] The Commission concluded that any concerns regarding the adequacy of the OATT should be addressed in that proceeding and not in the MBR Rulemaking proceeding. Therefore, in the NOPR the Commission proposed to continue to find that, where a seller or any of its affiliates owns, operates or controls transmission facilities, a Commission-approved OATT, as modified as a result of the OATT Reform Rulemaking, will adequately mitigate transmission market power.

401. In the NOPR, the Commission further stated that the finding that an

[396] NRECA at 29.

[397] This is due, in part, to the fact that the Commission's regulations require notice and an opportunity for the submitter to comment on the request. The Commission recently consolidated the notice and opportunity to comment provision in 18 CFR 388.112(d) with the notification prior to release found in 18 CFR 388.112(e). *See Critical Energy Infrastructure Information,* Order No. 683, FERC Stats. & Regs. ¶ 31,228 (2006).

[398] 18 CFR 33.9.

[399] *See http://www.ferc.gov/legal/admin-lit/model-protective-order.pdf*.

[400] *See* Duke at 30; Southern at 38–40; EPSA at 18–19.

[401] EPSA at 18–19.

[402] In Order No. 2000, the Commission found that "opportunities for undue discrimination continue to exist that may not be remedied adequately by [the] functional unbundling [remedy of Order No. 888]* * *" *Regional Transmission Organizations*, Order No. 2000, FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 ¶ 31,089 at 31,105 (1999), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 ¶ 31,092 (2000), *aff'd sub nom. Public Utility District No. 1 of Snohomish County, Washington* v. *FERC*, 272 F.3d 607 (D.C. Cir. 2001).

[403] See *Preventing Undue Discrimination and Preference in Transmission Service*, 70 FR 55796 (Sept. 23, 2005), FERC Stats. & Regs., ¶ 35,553 (2005); *Preventing Undue Discrimination and Preference in Transmission Service*, Notice of Proposed Rulemaking, 71 FR 32636 (Jun. 6, 2006), FERC Stats. & Regs. ¶ 32,603 (2006); *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 FR 12266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241 (2007), *reh'g pending*.

OATT adequately mitigates transmission market power rests on the assumption that individual sellers comply with their OATTs. If they do not, violations of the OATT may be cause to revoke market-based rate authority or to subject the seller to other remedies the Commission may deem appropriate, such as disgorgement of profits or civil penalties.[404] However, before the Commission will consider revoking an entity's market-based rate authority for a violation of the OATT, there must be a nexus between the OATT violation and the entity's market-based rate authority.

402. In addition, the Commission proposed that, if it determines, as a result of a significant OATT violation, that the market-based rate authority of a transmission provider will be revoked within a particular market, each affiliate of the transmission provider that possesses market-based rate authority will have it revoked in that same market on the effective date of revocation of the transmission provider's market-based rate authority.[405]

a. OATT Requirement

Comments

403. Several commenters state that merely having an OATT on file does not sufficiently mitigate vertical market power and that a utility's interpretation and implementation of its OATT can effectively eviscerate market power protections.[406] Some commenters do not believe that tariff changes alone will effectively mitigate vertical market power in the future and therefore request a post-implementation proceeding one year after the issuance of a final rule in the OATT Reform Rulemaking to explore the effectiveness of the updated OATT in assessing vertical market power.[407]

404. EPSA states that the outcome of the OATT Reform Rulemaking will determine the strength and efficacy of the vertical market power screen and stresses the interrelationship of that proceeding to this proposed rule; EPSA continues to advocate that the reform of Order No. 888 and the ability of the OATT to mitigate against market power effectively be evaluated on an ongoing basis.[408]

405. APPA/TAPS similarly state that, for purposes of the vertical market power analysis, it is too early to tell whether the OATT, as modified in the OATT Reform Rulemaking, will mitigate transmission market power.[409] TDU Systems argue that the proposals governing transmission planning and expansion in the OATT Reform Rulemaking are inadequate to mitigate the vertical market power of transmission-owning public utilities.[410]

406. The New York Commission states that the presence of an OATT may mitigate a seller's transmission market power, but only with respect to generator access to the transmission system. It submits that vertically integrated utilities may be able to exercise transmission market power in a manner that would not necessarily violate their OATTs, such as through outage scheduling (*e.g.*, delaying repair and maintenance of transmission lines in a load pocket in which an affiliated generator is located), transmission investment (*e.g.*, delaying or minimizing its investment in the bulk electric transmission system in a load pocket in which an affiliated generator is located), or voltage support (*e.g.*, inadequate support of voltage requirements and being slow to correct voltage support shortcomings).[411] EPSA agrees with the New York Commission that the Commission cannot assume that any transmission provider with a Commission-approved OATT on file has adequately mitigated transmission market power and that ''the Commission should require these utilities to demonstrate that they do not have the incentive or ability to engage in such behavior, before they are granted MBR status.''[412]

407. On the other hand, several commenters support the Commission's proposal to maintain the long-standing presumption that a Commission-approved OATT will adequately mitigate transmission market power.[413] EEI states that the comprehensive approach that the Commission has taken to reform the OATT in the OATT Reform Rulemaking is the best approach to assess the adequacy of the OATT to mitigate transmission market power. EEI states that the Commission should continue to find that a Commission-approved OATT, as modified as a result of the OATT Reform Rulemaking, adequately mitigates transmission market power.[414]

Commission Determination

408. The Commission will adopt the NOPR proposal that, to the extent that a public utility with market-based rates, or any of its affiliates, owns, operates, or controls transmission facilities, the Commission will require that a Commission-approved OATT be on file before granting such seller market-based rate authorization. We recognize that the Commission has granted a number of entities waiver of the requirement to file an OATT where the filing entity satisfies the Commission's standards for the grant of such waivers.[415] The Commission will continue to grant waiver of the OATT requirement on a case-by-case basis, and will continue to allow sellers to rely on the grant of such waiver to satisfy the vertical market power part of the analysis. If a seller that previously received waiver of the OATT requirement seeks to continue to rely on that waiver to satisfy the vertical market power part of the analysis, it must make an affirmative statement in its updated market power analysis that it previously received such a waiver, that such waiver remains appropriate, and the basis for that claim. In addressing our vertical market power concerns, a seller, including its affiliates, that does not own, operate or control transmission facilities must make an affirmative statement that neither it, nor any of its affiliates, owns, operates or controls any transmission facilities.

409. In the NOPR, we stated that concerns regarding the adequacy of the OATT should be addressed in the OATT Reform Rulemaking. The Commission received over 6,000 pages of comments relating to potential reforms to the *pro forma* OATT in that proceeding, and on February 16, 2007 issued a Final Rule adopting numerous improvements to the *pro forma* OATT that will further limit opportunities for transmission providers to unduly discriminate against transmission customers. As a result, we do not address in this Final Rule specific reforms to the OATT. In addition, the Commission declined in Order No. 890 to establish a one-year review period for the reformed *pro forma* OATT. The Commission stated it will continue to actively monitor compliance with its orders and, as necessary, institute further proceedings

[404] NOPR at P 91 (citing *The Washington Water Power Co.*, 83 FERC ¶ 61,282 (1998)).

[405] NOPR at P 91.

[406] *See, e.g.*, Suez/Chevron at 6; Reliant at 8.

[407] Suez/Chevron at 6; EPSA at 20.

[408] EPSA reply comments at 2, 5.

[409] APPA/TAPS at 6.

[410] TDU Systems at 24.

[411] New York Commission at 2–4.

[412] EPSA reply comments at 5–6 (citing New York Commission at 2–4).

[413] Duke at 29–32; EEI at 44–45; Southern at 38–40; MidAmerican reply comments at 2.

[414] EEI reply comments at 31–35.

[415] *Black Creek Hydro, Inc.*, 77 FERC ¶ 61,232 at 61,941 (1996) (granting waiver of Order No. 888 for public utilities that can show that they own, operate, or control only limited and discrete transmission facilities (facilities that do not form an integrated transmission grid), until such time as the public utility receives a request for transmission service).

to meet its statutory obligation to remedy undue discrimination.[416]

410. In response to the concerns of the New York Commission and EPSA that vertically integrated utilities may exercise vertical market power without violating their OATTs through actions such as outage scheduling, investment decisions and inadequate voltage support, we note that the OATT does address such matters as the planning and expansion of facilities, the duty to provide firm and non-firm service and good utility practice. These provisions impose definite obligations on transmission providers. As additional examples, outage scheduling aimed at affecting market prices may constitute market manipulation, and inadequate voltage support may violate a reliability standard under FPA section 215. These provisions adequately address the concerns of the New York Commission and EPSA.

b. OATT Violations and MBR Revocation

Comments

411. A number of commenters agree with the Commission that market-based rate authority should not be revoked unless and until the Commission finds a direct nexus between the OATT violation and the entity's market-based rate authority.[417] EEI states that the Commission should not presume that an OATT violation is sufficient cause to revoke a transmission provider's market-based rate authority because there is no basis for such a presumption.[418] Instead, EEI argues that the Commission should carefully review all facts and circumstances before determining that an OATT violation was a willful exercise in undue discrimination intended to benefit a seller's sales at market-based rates.[419]

412. EPSA asserts that any violation of an entity's OATT in order to favor its own sales or its affiliates would create a nexus to the entity's market-based rate authority. If the Commission does not clarify this point, EPSA requests explanation regarding what exactly would constitute a nexus between an OATT violation and an entity's market-based rates.[420]

413. TDU Systems state that it is unclear what the nexus requirement entails. They propose that if the transmission provider or one of its affiliates has market-based rate authority, there should be a rebuttable presumption that a violation of the OATT has the requisite nexus to support revocation of the market-based rate authority of the transmission provider and its affiliates.[421] TDU Systems state that it should be up to a seller to rebut that presumption.

414. APPA/TAPS assert that the nexus standard adds an unnecessary and counter-productive test.[422] APPA/TAPS submit that if an OATT violation denies, delays, or diminishes the availability of transmission service or raises its costs, that alone should suffice for consideration of revocation of market-based rate authority. They argue that whether the violation had a nexus to the seller's market-based rate sales may be irrelevant. APPA/TAPS state that a nexus requirement could divert the Commission and injured parties through needless disputes about whether the alleged violator used the OATT violation to enable a specific sale under its market-based rate tariff authority, ignoring the larger picture painted by the transmission provider's anticompetitive conduct and exercise of transmission market power. Thus, instead of the ''nexus'' standard, APPA/TAPS states that the Commission should require that the OATT violation be ''material,'' *i.e.*, one that denies customers the just, reasonable and non-discriminatory and comparable transmission service that is essential to mitigation of transmission market power.[423]

415. Reliant suggests that the Commission should strengthen its vertical market power analysis by looking at the extent to which a transmission provider has denied transmission access to competing suppliers and should seek justification for such denials.[424] For those transmission providers seeking market-based rate authority, Reliant asserts that any suppliers unable to reach a customer as a result of an inappropriate denial should not be included as competing generation in the transmission provider's horizontal market power screens until the transmission provider remedies the problem.[425]

416. Duke urges the Commission to clarify that a seller's market-based rate authority should not be subject to limitation or revocation if it participates in an RTO that is the subject of an OATT violation. According to Duke, once the transmission owner transfers control over its facilities to an RTO, adherence to the OATT is in the control of the RTO, not the transmission owner.[426]

Commission Determination

417. We will adopt the NOPR proposal to revoke an entity's market-based rate authority in response to an OATT violation only upon a finding of a nexus between the specific facts relating to the OATT violation and the entity's market-based rate authority, and reiterate our statement in the NOPR that an OATT violation may subject the seller to other remedies the Commission may deem appropriate, such as disgorgement of profits or civil penalties.[427] As stated in the NOPR, the finding that an OATT adequately mitigates transmission market power rests on the assumption that individual entities comply with the OATT and there may be OATT violations in circumstances that, after applying the factors in the Enforcement Policy Statement,[428] merit revocation or limitation of market-based rate authority. We find, however, that it is inappropriate to revoke a seller's market-based rate authority for an OATT violation unless there is a nexus between the specific facts relating to the OATT violation and the seller's market-based rate authority. This will ensure that our actions are not arbitrary or capricious and that they are based on an adequate factual record. We will not, as TDU Systems suggest, adopt a rebuttable presumption that any OATT violation has the requisite nexus to support revocation of market-based rate authority. There is a wide range of types of OATT violations, including ones that may be inadvertent and ones that are neither intended to affect, nor in fact affect, the market-based rate sales of the transmission provider or its affiliates. We therefore believe adoption of a general rebuttable presumption of a nexus for any and all OATT violations is not justified.

418. Several commenters sought clarification regarding what would constitute a sufficient nexus between the specific facts relating to the OATT violation and the seller's market-based rate authority. Determining what

[416] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 42.

[417] EEI reply comments at 31–35; MidAmerican reply comments at 2. *See also* Duke at 29 (OATT violation should be a material violation and related in some way to the seller exercising market power).

[418] EEI reply comments at 31–35.

[419] EEI reply comments at 34; PNM/Tucson at 10–12.

[420] EPSA at 23–24.

[421] TDU Systems at 21–23.

[422] APPA/TAPS at 81–82.

[423] *Id.* at 82.

[424] *See* Reliant at 8–9.

[425] *See id.*

[426] Duke at 29–32.

[427] NOPR at P 91 (citing *The Washington Water Power Company,* 83 FERC ¶ 61,282 (1998)).

[428] *Enforcement of Statutes, Orders, Rules and Regulations,* Policy Statement on Enforcement, 113 FERC ¶ 61,068 (2005) (Enforcement Policy Statement).

constitutes a sufficient factual nexus is best left to a case-by-case consideration. The wide range of positions among commenters on how to define a sufficient factual nexus itself suggests that this finding is best made after review of a specific factual situation. Some commenters assert that a finding of a ''material'' violation of the OATT would be sufficient. We disagree. While a seller's inconsequential OATT violation would not serve as a basis for revoking that entity's market-based rate authority, our view is that revocation is warranted only when an OATT violation has occurred and the violation had a nexus to the market-based rate authority of the violator or its affiliates.

419. The Commission emphasizes that we have discretion to fashion remedies for OATT violations that relate to the violator's market-based rate authority in instances in which we do not find sufficient justification for revocation of that authority. For example, in appropriate circumstances, we may modify or add additional conditions to the violator's market-based rate authority or impose other requirements to help ensure that the violator does not commit future, similar misconduct. We also will consider whether to impose sanctions such as assessment of civil penalties for particularly serious OATT violations in addition to revocation of the violator's market-based rate authority.

420. We agree with Duke that a seller's market-based rate authority should not be subject to limitation or revocation if it participates in an RTO that is the subject of an OATT violation committed by the RTO. We note, however, that if the seller itself is involved in an OATT violation, the Commission will investigate the seller's actions where appropriate, and may revoke market-based rate authority even though the seller is in an RTO.

421. With regard to Reliant's suggestion that the Commission should examine the extent to which a transmission provider has denied transmission access to competing suppliers as part of its vertical market power analysis, we will allow intervenors on a case-by-case basis to file evidence if they believe they have been denied transmission access in violation of the OATT. Depending on specific facts, such denials could constitute an OATT violation and could warrant remedies such as a reduction of competing supplies for purposes of the horizontal analysis.

c. Revocation of Affiliates' MBR Authority

Comments

422. Some commenters oppose the proposal to revoke the market-based rate authority of all affiliates of a transmission provider within a particular market, regardless of whether they were involved in the transmission provider's violation of its OATT. These commenters argue that the proposal to revoke all affiliates' market-based rate authority ignores the principles of the Commission's code of conduct and standards of conduct, including provisions restricting the sharing of market information and requiring separation of functions.[429] They argue that, in light of the separation of a company's marketing function and transmission function under the standards of conduct, a company's market-based rates should not be revoked because of an OATT violation by an affiliated transmission owner unless there has also been a violation of the standards of conduct, and there is a nexus between the standards of conduct violation and the OATT non-compliance.[430] They assert that, unless there is a violation of the standards of conduct, merchants will have no involvement in the actions of transmission providers.[431]

423. Xcel submits that, before imposing a penalty that would effectively penalize the merchant function, the Commission should require a demonstration that a utility's transmission function violated the OATT so as to knowingly benefit the activities of its merchant function.[432] Xcel and Allegheny Energy state that the Commission should not penalize the merchant side of an entity when the OATT violation by the transmission provider causes no harm, was not the result of deliberate manipulative conduct, was not part of a pattern of misconduct, or did not involve senior management of the transmission provider.[433] Similarly, Indianapolis P&L advocates punishment of a marketing or generation-only affiliate only to the extent such affiliate colludes or conspires with such OATT mis-administration or if such an affiliate financially benefits from such an act.[434]

[429] *See* Ameren at 8–11; PNM/Tucson at 10–12; EEI reply comments at 33–35; Avista at 12–13; EEI at 54; Indianapolis P&L at 6–7.

[430] *See* PG&E at 3, 12–14; Xcel at 2 and 16.

[431] PG&E at 13.

[432] Xcel at 16–17. *See also* Avista at 12–13; PNM/Tucson at 10–12.

[433] Allegheny Energy at 9–10; Xcel at 16–17.

[434] Indianapolis P&L at 6–7.

Commission Determination

424. In response to concerns raised by commenters, we do not adopt the proposal from the NOPR to revoke the market-based rate authority of each affiliate of a transmission provider that loses its market-based rate authority within a particular market as a result of the transmission provider's OATT violation. Rather, we will create a rebuttable presumption that all affiliates of a transmission provider should lose their market-based rate authority in each market in which their affiliated transmission provider loses its market-based rate authority as a result of an OATT violation. We will allow an affiliate of a transmission provider to retain its market-based rate authority in a market area if the affiliate overcomes the rebuttable presumption with respect to that market area.

425. This issue generally will arise when a transmission provider merits revocation of its market-based rate authority as a result of an OATT violation. We have long held that the existence of an OATT is deemed to mitigate vertical market power by a transmission provider and its affiliates in a particular market. An OATT violation by a transmission provider that merits revocation of the transmission provider's market-based rate authority in a particular market will, at a minimum, raise the question whether the transmission provider's affiliates continue to qualify for market-based rates in that market under the standards that we have established.[435]

[435] We observe that specific situations in which transmission providers have agreed to resolve staff allegations that they engaged in OATT violations have involved transactions with affiliates. *See Idaho Power Company, et al.*, 103 FERC ¶ 61,182 (2003) (settlement of, among other issues, a practice whereby a transmission provider permitted its merchant function to request non-firm transmission to enable the merchant function to make off-system sales that by definition were not used to serve native load, so that the transmission did not qualify for the ''native load'' priority specified in section 28.4 of the transmission provider's OATT); *Cleco Corporation, et al.*, 104 FERC ¶61,125 (2003) (settlement between Enforcement staff and a transmission provider (and others in the corporate family) that provided a unique type of transmission service for its affiliate that was neither made available to non-affiliates nor included in its FERC tariff); *Tucson Electric Power Company,* 109 FERC ¶ 61,272 (2004) (operational audit in which staff found that, among other matters, a transmission provider permitted its wholesale merchant function to purchase hourly non-firm and monthly firm point-to-point transmission service using an off-OASIS scheduling procedure while the transmission provider did not post on its OASIS the availability of capacity on these paths); *South Carolina Electric & Gas Company, et al.*, 111 FERC ¶ 61,217 (2005) (settlement of Enforcement staff allegation that a transmission provider made available firm point-to-point transmission service to its affiliated merchant function that did not submit

Continued

As a result, we believe that it is appropriate to establish a rebuttable presumption that if we find that a transmission provider should lose its market-based rate authority in a particular market, all affiliates of the transmission provider should also lose their market-based rate authority in the same market.

426. We are mindful, however, that the circumstances of a particular affiliate may not always justify the imposition of a remedy so severe as revocation of market-based rate authority in a particular market when its affiliated transmission provider loses its market-based rate authority in that market as a result of an OATT violation. To ensure that a determination to revoke market-based rate authority in a particular market for a transmission provider and all of its affiliates that possess such authority is adequately based upon record evidence, we will allow an opportunity for each such affiliate to make a showing that it should retain its market-based rate authority or that enforcement action against it should be less severe than revocation. The determination whether an affiliate has overcome the rebuttable presumption depends on an analysis of specific facts in the record. Relevant facts would include, for example, whether (1) The affiliate knew of, participated in, or was an accomplice to the OATT violation, (2) the affiliate assisted the transmission provider in exercising market power, or (3) the affiliate benefited from the violation.

427. Consistent with our approach to revocation of a transmission provider's market-based rates, the Commission clarifies that a decision to revoke the market-based rate authority of the transmission provider's affiliates in the affected market will also be based on a finding that the transmission provider's violation of its OATT has a nexus to the market-based rate authority of those affiliates.

transmission schedules with specific receipt points for the service as required by section 13.8 of the transmission provider's OATT); and *MidAmerican Energy Company*, 112 FERC ¶ 61,346 (2005) (operational audit in which staff found, among other things, that a transmission provider permitted its wholesale merchant function to (a) Use network transmission service to bring short-term energy purchases onto its system while it simultaneously made off-system sales, inconsistently with the preamble to Part III of the transmission provider's OATT and section 28.6 of its OATT; and (b) confirm firm network transmission service requests without identifying a designated network resource or acquiring an associated network resource, in some instances using this service to deliver short-term energy purchases used to facilitate off-system sales, inconsistent with section 29.2 or section 30.6 of the transmission provider's OATT).

2. Other Barriers to Entry

Commission Proposal

428. The Commission proposed in the NOPR that, in order for a seller to demonstrate that it satisfies the Commission's vertical market power concerns, it must demonstrate that neither it nor its affiliates can erect other barriers to entry (*i.e.*, barriers other than transmission). In this regard, the Commission proposed to continue to require a seller to provide a description of its affiliation, ownership or control of inputs to electric power production (*e.g.*, fuel supplies within the relevant control area); ownership or control of gas storage or intrastate transportation or distribution of inputs to electric power production; and ownership or control of sites for new generation capacity development. The Commission also proposed to require sellers to make an affirmative statement that they have not erected barriers to entry into the relevant market and that they cannot do so.

429. In addition, the Commission proposed to provide additional regulatory certainty by clarifying which inputs to electric power production the Commission will consider as other barriers to entry in its vertical market power review, and sought comments on this proposal. Specifically, the Commission proposed that the analysis continue to include the consideration of ownership or control of sites for development of generation in the relevant market, fuel inputs such as coal facilities in the relevant market, and the transportation, storage or distribution of inputs to electric power production such as intrastate gas storage and distribution systems, and rail cars/ barges for the transportation of coal.

430. The Commission also clarified that sellers need not address interstate transportation of natural gas supplies because such transportation is regulated by this Commission.[436] The Commission explained that its open access regulations adequately prevent sellers from withholding interstate pipeline capacity. In addition, interstate pipeline capacity held by firm shippers that is not utilized or released is available from the pipeline on an interruptible basis. As to the commodity, the Commission noted that Congress has found the natural gas market competitive.[437]

431. The Commission also sought comment on whether ownership or control of other inputs to electric power production should be considered as potential barriers to entry and, if so, what criteria the Commission should use to evaluate evidence that is presented.

Comments

432. Several commenters state that the Commission's other barriers to entry criteria are long-standing, well established and thus no expansion of current policy is necessary.[438] They submit that the requirement that the analysis include the consideration of ownership or control of sites for development of generation in the relevant market, fuel inputs such as coal supplies in the relevant market, and the transportation, storage or distribution of inputs to electric power production such as intrastate gas storage and distribution systems, and rail cars/ barges for the transportation of coal, is broad and provides sufficient information for the Commission to assess the seller's potential to erect barriers to entry. They assert that this information, coupled with the proposal to require sellers to make an affirmative statement that they have not erected barriers to entry into the relevant market and that they cannot do so, provides the Commission with appropriate information.[439]

433. APPA/TAPS suggest that the proposed entry barriers affirmation should be signed and affirmed by a senior corporate official.[440] However, APPA/TAPS state that the Commission should not codify the specific entry barriers that it will consider given the ever-changing nature of electricity markets.[441] They submit that while illustrations of entry barriers can provide guidance to sellers and market participants, the Commission should not limit the kinds of entry barriers it will consider.

434. Sempra states that, to the extent the new analytic framework (the consolidation of the former transmission market power and other barriers to entry factors into the vertical market power analysis) would recognize existing

[436] NOPR at P 93 (citing *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations*, Order No. 636, 57 FR 13267 (Apr. 16, 1992), FERC Stats. & Regs. Regulations Preambles January 1991–June 1996 ¶ 30,939 (Apr. 8, 1992)).

[437] NOPR at P 93 (citing Natural Gas Wellhead Decontrol Act of 1989, Pub. L. 101–60, 103 Stat. 157 (1989); Natural Gas Policy Act of 1978, section 601(a)(1), 15 U.S.C. 3431 (deregulating the wellhead price of natural gas)).

[438] Allegheny Energy at 9–10; Southern at 38–40; EEI at 44–45.

[439] *See, e.g.*, New Jersey Board at 3.

[440] APPA/TAPS at 6, 85.

[441] APPA/TAPS at 6, 84–85.

precedent and not work to place additional burdens on market-based rate sellers, Sempra would support it.[442]

435. Several sellers support continuation of the Commission's policy that sellers need not address natural gas and its interstate transportation as part of their vertical market power analysis.[443] In contrast, a commenter states that the Commission should not make a blanket exemption for sellers or their affiliates who own or control natural gas pipeline capacity. Notwithstanding the Commission's statement that natural gas interstate pipelines are regulated by the Commission and that the regulations adequately prevent sellers from withholding capacity, this commenter argues that the natural gas open access rules do not adequately mitigate vertical market power in all situations. It encourages the Commission to require sellers with significant firm interstate pipeline capacity rights to demonstrate that they do not have vertical market power.[444]

436. APPA/TAPS state that the Commission should clarify that it will consider control over interstate natural gas transportation if the issue is raised in a market-based rate proceeding.[445] APPA/TAPS state that even if sellers do not have to address interstate gas transportation as part of the vertical market power test, intervenors should not be precluded from raising concerns and introducing evidence regarding a seller's position in the interstate natural gas transportation market as a potential entry barrier and APPA/TAPS seek clarification in this regard.[446]

437. Several commenters state that the markets for the other inputs to generation factor (*e.g.*, fuel supply other than natural gas, transportation and storage) are workably competitive and provide few opportunities for a seller to raise entry barriers. They therefore suggest that the Commission create a rebuttable presumption that the markets for other factor inputs such as coal, oil and distillate commodity markets, the transportation and storage of these fuels, sites for new plants, etc., are workably competitive. They urge that, absent a showing to the contrary, ownership or control of such assets need not be analyzed.[447] In this regard, Duke states that the Commission should allow sellers to make the representation that they cannot erect such barriers, while allowing other parties to introduce evidence challenging such an assertion.[448]

438. PG&E states that, similar to the rules for interstate transportation of natural gas supplies (under which Commission open access regulations adequately prevent sellers from withholding interstate gas pipeline capacity), State regulation of access to gas storage, natural gas pipelines, or natural gas distribution should be a basis for finding that an entity with ownership or control of such assets cannot erect barriers to entry or otherwise hold or exercise vertical market power in the generation market.[449]

439. SoCal Edison urges the Commission to clarify that, with regard to sites for building generation, mere ownership of real estate does not reasonably support an inference of a barrier to entry, and that sellers are not required, in the first instance, to make any affirmative demonstration of the absence of potential that their real estate holdings might constitute a theoretical barrier to entry. Rather, the Commission should clarify that it would pursue such inquiry only to the extent colorable issues are raised by way of protest or intervention.[450] Sempra states the Commission should modify the regulatory text in three respects. First, the Commission should explicitly exclude from the definition of ''inputs to electric power production'' in proposed § 35.36(a)(4) interstate transportation of natural gas supplies (both ownership/control of facilities as well as ownership/control of capacity) and the gas commodity itself. Second, the Commission should also exclude from the definition of ''inputs to electric power production'' intrastate natural gas facilities or distribution facilities, particularly where such facilities are operated under pervasive State regulations and in accordance with open access principles. Third, the Commission should make clear in this provision and at § 35.27(e) of its proposed regulations (pertaining to a seller's vertical market power analysis), that the only ''inputs'' that need to be addressed are those present in the seller's relevant geographic market(s).[451]

Commission Determination

440. As discussed above, the Commission will adopt the NOPR proposal to consider a seller's ability to erect other barriers to entry as part of the vertical market power analysis, but we will modify the requirements when addressing other barriers to entry. We also provide clarification below regarding the information that a seller must provide with respect to other barriers to entry (including which inputs to electric power production the Commission will consider as other barriers to entry) and we modify the proposed regulatory text in that regard.

441. In this rule, the Commission draws a distinction between two categories of inputs to electric power production: One consisting of natural gas supply, interstate natural gas transportation (which includes interstate natural gas storage), oil supply, and oil transportation, and another consisting of intrastate natural gas transportation, intrastate natural gas storage or distribution facilities; sites for generation capacity development; and sources of coal supplies and the transportation of coal supplies such as barges and rail cars.

442. With regard to the first category, based upon the comments received and further consideration, the Commission will not require a description or affirmative statement with regard to ownership or control of, or affiliation with an entity that owns or controls, natural gas and oil supply, including interstate natural gas transportation and oil transportation.

443. In the case of natural gas, prices for wellhead sales were decontrolled by Congress.[452] Further, the Commission has granted other sellers blanket authority to make sales at market rates. In the case of transportation of natural gas, pipelines operate pursuant to the open and non-discriminatory requirements of Part 284 of the Commission's regulations.[453] These regulations mandate that all available pipeline capacity be posted on the pipelines' Web site, and that available capacity cannot be withheld from a

[442] Sempra at 6–7.

[443] *See* Constellation at 25; Duke at 30; PG&E at 13; Sempra at 6.

[444] Drs. Broehm and Fox-Penner at 14–15.

[445] APPA/TAPS at 82–85.

[446] APPA/TAPS at 6.

[447] *See, e.g.*, Duke at 30–32; Constellation at 23–27.

[448] Duke at 30–32.

[449] *See* PG&E at 3, 13–14.

[450] SoCal Edison at 2, 19.

[451] Sempra at 6.

[452] *INGAA* v. *FERC*, 285 F.3d 18 (D.C. Cir. 2002); Natural Gas Decontrol Act of 1989, H.R. Rep. No. 101–29, 101st Cong., 1st Sess., at 6 (1989).

[453] *See, e.g., Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations*, Order No. 636, 57 FR 13267 (Apr. 16, 1992), FERC Stats. & Regs. Regulations Preambles January 1991–June 1996 ¶ 30,939 (Apr. 8, 1992); *Regulation of Short-Term Natural Gas Transportation Services and Regulation of Interstate Natural Gas Transportation Services*, Order No. 637, FERC Stats. & Regs. Regulations Preambles July 1996–December 2000 ¶ 31,091 (Feb. 9, 2000); *order on reh'g*, Order No. 637–A, FERC Stats. & Regs. Regulations Preambles July 1996–December 2000) ¶ 31,099 (May 19, 2000); *reh'g denied*, Order No. 637–B, 92 FERC ¶ 61,062 (2000); *aff'd in part and denied in part.*

shipper willing to pay the maximum approved tariff rate.

444. Similarly, we note that oil pipelines are common carriers under the Interstate Commerce Act, specifically under section 1(4), and are required to provide transportation service ''upon reasonable request therefore'' [454] and that Congress has not chosen to regulate sales of oil.

445. In response to APPA/TAPS' request for clarification, we note that as an initial matter, to the extent intervenors are concerned about a seller's market power from ownership or control of interstate natural gas transportation, this would be actionable first in a complaint proceeding under section 5 of the Natural Gas Act before turning to market-based rate consequences.

446. With regard to the second category, in light of the comments received, and upon further consideration, the Commission adopts a rebuttable presumption that sellers cannot erect barriers to entry with regard to the ownership or control of, or affiliation with any entity that owns or controls, intrastate natural gas transportation, intrastate natural gas storage or distribution facilities; sites for generation capacity development; and sources of coal supplies and the transportation of coal supplies such as barges and rail cars.[455] To date, the Commission has not found such ownership, control or affiliation to be a potential barrier to entry warranting further analysis in the context of market-based rate proceedings. However, unlike the first category of inputs, the Commission does not have sufficient evidence to remove these inputs from the analysis entirely. Accordingly, we will rebuttably presume that ownership or control of, or affiliation with an entity that owns or controls, intrastate natural gas transportation, intrastate natural gas storage or distribution facilities; sites for generation capacity development; and sources of coal supplies and the transportation of coal supplies such as barges and rail cars do not allow a seller to raise entry barriers, but will allow intervenors to demonstrate otherwise. We note that this rebuttable presumption only applies if the seller describes and attests to these inputs to electric power production, as described herein.

447. With regard to this second category of inputs to electric power production, we will require a seller to provide a description of its ownership or control of, or affiliation with an entity that owns or controls, intrastate natural gas transportation, storage or distribution facilities; sites for generation capacity development; and sources of coal supplies and the transportation of coal supplies such as barges and rail cars. The Commission will require sellers to provide this description and to make an affirmative statement, with some modifications to the affirmative statement from what was proposed in the NOPR. Instead of requiring sellers to make an affirmative statement that they have not erected barriers to entry into the relevant market, we will require sellers to make an affirmative statement that they have not erected barriers to entry into the relevant market and will not erect barriers to entry into the relevant market. We clarify that the obligation in this regard applies both to the seller and its affiliates, but is limited to the geographic market(s) in which the seller is located.

448. We therefore modify the proposed regulations to require a seller to provide a description of its ownership or control of, or affiliation with an entity that owns or controls, intrastate natural gas transportation, intrastate natural gas storage or distribution facilities; sites for generation capacity development; sources of coal supplies and the transportation of coal supplies such as barges and rail cars, to ensure that this information is included in the record of each market-based rate proceeding. In addition, a seller is required to make an affirmative statement that it has not erected barriers to entry into the relevant market and will not erect barriers to entry into the relevant market.

449. While some commenters raise concerns that codification of these possible barriers may inappropriately limit the analysis of a seller's potential to erect other barriers to entry, we clarify that we are codifying what showing a seller must make in order to receive authority to make sales of electric power at market-based rates. By so doing, we are not preventing intervenors from raising other barriers to entry concerns for consideration on a case-by-case basis. This approach will allow unique or newly developed barriers to entry to be brought before the Commission.

450. We will not adopt APPA/TAPS' proposal that the affirmation be signed and affirmed by a senior corporate officer. Section 35.37(b) of the Commission's regulations requires sellers to ''provide accurate and factual information and not submit false or misleading information, or omit material information, in any communication with the Commission * * *''.[456] The Commission has ample authority to enforce its regulations, and therefore does not believe that it is necessary in these circumstances to require the affirmative statement to be signed by a senior corporate official.

451. The changes made to the evaluation of other barriers to entry, as described above, should not be more burdensome on market-based rate sellers than that which is currently in place. For the most part, the Commission is maintaining its current policy, with some variation and additional guidance on what is required. The policy adopted in this Final Rule should provide sellers with additional clarity regarding what needs to be addressed as a potential other barrier to entry and the way in which to address it.

### 3. Barriers Erected or Controlled by Other Than The Seller

#### Comments

452. APPA/TAPS state that entry conditions and barriers, regardless of origin, need to be considered in both the horizontal and vertical market power tests.[457] APPA/TAPS state that the Commission should not focus solely on entry barriers erected by the seller itself and that the Commission must be receptive to claims that entry barriers in the seller's market provide or enhance market power, even if the seller itself did not erect the barriers.[458] Another commenter states that the Commission should maintain a separate evaluation on other barriers to entry that are not caused by a seller, thus requiring a seller to address barrier to entry issues to the relevant market, even if those barriers are not caused by a seller or its affiliates.

#### Commission Determination

453. The Commission finds that it is not reasonable to routinely require sellers to make a showing regarding potential barriers to entry that others might erect and that are beyond the seller's control. However, we will allow intervenors to present evidence in this regard, and by this means we will be able to assess the existence of barriers to entry beyond the seller's control but which may affect the seller's ability to exercise market power. Should a potential barrier in the relevant market

[454] 49 App. U.S.C. 1(4).

[455] We modify the definition of ''inputs to electric power production'' in 18 CFR 35.36(a)(4) to reflect this clarification.

[456] 18 CFR 35.41(b) (formerly 18 CFR 35.37(b)).

[457] APPA/TAPS at 6.

[458] APPA/TAPS at 82–84.

be raised by an intervenor, the Commission will address such claims on a case-by-case basis.

4. Planning and Expansion Efforts

454. In the NOPR, the Commission noted that several commenters had suggested that a transmission planning and expansion process can ameliorate vertical market power, and, accordingly, the Commission was seeking comment on the issues of transmission planning and expansion in the notice of proposed rulemaking in the OATT Reform Rulemaking. The Commission sought comment in the NOPR on whether the planning and expansion efforts in the OATT Reform Rulemaking would address commenters' concerns here.

Comments

455. APPA/TAPS state that there will be a continuing need to address transmission market power issues, even after adoption of a revised *pro forma* OATT, because the improvements in transmission planning and expansion will not be immediately felt.[459] EPSA states that it advocates robust, independent and mandatory regional planning as a means to combat vertical market power and ensure competitive markets.[460]

456. TDU Systems recommend that the Commission revoke a transmission provider's market-based rate authority if it fails to build transmission to accommodate the needs of its transmission customers demonstrated through an open, joint planning process.[461] TDU Systems submit that willful failure to plan, maintain and expand the transmission system to meet transmission customers' needs is an abuse of vertical market power and creates structural barriers to competition.

457. ELCON states that while it is encouraged by proposals in the OATT Reform Rulemaking, it recommends that transmission market power be the subject of a new rulemaking.[462] Similarly, EPSA asserts that a technical conference to develop the barriers to entry portion of the screens would help ensure an open, accessible, and robust competitive market.[463]

Commission Determination

458. We find that our reforms to the *pro forma* OATT to require coordinated transmission planning on a local and regional level address the concerns raised by commenters. While we recognize that the transmission planning reforms in Order No. 890 are still in the process of being implemented, failure to plan, maintain and expand the transmission system in accordance with the applicable, Commission-approved OATT has always been, and will continue to be, an OATT violation. Order No. 890 provides for revocation of an entity's, and possibly that of its affiliates, market-based rate authority in response to an OATT violation upon a finding of a specific factual nexus between the violation and the entity's market-based rate authority.[464] Should such a violation occur, the Commission will address it in that context. The Commission does not find that the need exists to convene a technical conference in this regard. The OATT Reform Rulemaking dealt extensively with this issue and the Commission finds that it has been adequately addressed in Order No. 890.

5. Monopsony Power

459. In the NOPR, the Commission sought comment on whether the exercise of buyer's market power by the transmission provider should be considered a potential barrier to entry and, if so, what criteria the Commission should use to evaluate evidence that is presented.

Comments

460. Allegheny states that the NOPR provided no explanation for why a transmission provider's buyer's market power should be relevant to the analysis.[465] EEI argues that the Commission should not consider buyer's market power as a barrier to entry because it is not relevant to the analysis. According to EEI, the market-based rate analysis considers the ability of the applicant to exercise market power as a seller, not a buyer, which is consistent with the Commission's authority under section 205 of the FPA, which regulates the sale of electricity. EEI asserts that states generally have jurisdiction over the purchase of electricity by franchised utilities.[466]

461. EPSA argues that if a utility holds a dominant purchasing position in the wholesale marketplace that allows it to exert excessive and discretionary buying power (of both supply and supply generation facilities), the exercise of market power will then lie with the buyer, not the seller. This problem is exacerbated when such a purchasing utility also owns, controls or dispatches its own proprietary supply and the relevant transmission system.

462. EPSA states that some would argue that the Commission cannot order economic dispatch or competitive solicitation because the FPA grants the Commission jurisdiction over sales, not purchases. However, EPSA submits that the Commission would not be mandating purchases, but eliminating the exercise of market power which directly raises the prices for wholesale sales. In so doing, the Commission would be using its tools under sections 205 and 206 of the FPA to ensure just and reasonable wholesale rates by allowing competitive alternatives to enter the market and protecting consumers from practices that will result in excessive rates and charges. EPSA argues that the Commission must develop a transparent, methodical process for assessing this segment of the vertical market power analysis. EPSA submits that load serving entities that are transmission providers must, in addition to providing enhanced transmission services, facilitate accessible long-term markets through all-source competitive procurement processes, preferably via state created and supervised means, with independent third party oversight. It asserts that the Commission must achieve and ensure these goals through a transparent, well-developed process. EPSA requests that the Commission convene a technical conference in order to fully develop that process and ensure that barriers to entry are properly mitigated.[467]

Commission Determination

463. EPSA's proposal not only raises jurisdictional issues, but EPSA has failed to provide specific instances in which the exercise of monopsony power has taken place and has provided no guidance as to how buyer market power should be measured (even assuming the Commission has jurisdiction to address it). The Commission does not believe it is appropriate to attempt to address these difficult issues without specific evidence of monopsony power and a clear delineation of the State-Federal jurisdiction issues that would arise in the context of a specific seller and specific set of circumstances. For the same reason, we will not grant EPSA's request to convene a technical conference to address such issues generically. Until EPSA or others provide such information concerning a particular seller in either a market-based

[459] APPA/TAPS at 80–85.

[460] EPSA at 27.

[461] TDU Systems at 21–23.

[462] ELCON at 5–6.

[463] EPSA at 28.

[464] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 1743, 1747.

[465] Allegheny Energy at 10.

[466] EEI at 43.

[467] EPSA at 26–27.

rate proceeding or a complaint, we defer judgment on the many difficult issues raised by EPSA.

### *C. Affiliate Abuse*

#### 1. General Affiliate Terms and Conditions

##### a. Codifying Affiliate Restrictions in Commission Regulations

Commission Proposal

464. In the NOPR the Commission proposed to discontinue referring to affiliate abuse as a separate ''prong'' of the market-based rate analysis and instead proposed to codify in the regulations at 18 CFR part 35, subpart H, an explicit requirement that any seller with market-based rate authority must comply with the affiliate power sales restrictions and other affiliate restrictions. The Commission proposed to address affiliate abuse by requiring that the conditions set forth in the proposed regulations be satisfied on an ongoing basis as a condition of obtaining and retaining market-based rate authority. The Commission indicated that a seller seeking to obtain or retain market-based rate authority will be obligated to provide a detailed description of its corporate structure so that the Commission can be assured that the Commission's requirements are being applied correctly. In particular, the Commission proposed that sellers with franchised service territories be required to make a showing regarding whether they serve captive customers and to identify all ''non-regulated'' power sales affiliates, such as affiliated marketers and generators.[468]

465. The Commission further proposed that, as a condition of receiving market-based rate authority, sellers must adopt the MBR tariff (included as Appendix A to the NOPR) which includes a provision requiring the seller to comply with, among other things, the affiliate restrictions in the regulations. The Commission noted that failure to satisfy the conditions set forth in the affiliate restrictions will constitute a tariff violation. The Commission sought comment on these proposals

Comments

466. As a general matter, commenters support the Commission's proposal to codify the affiliate restrictions in the Commission's regulations.[469] No comments were received opposing the proposal to codify affiliate restrictions in the Commission's regulations.

Commission Determination

467. The Commission will adopt the proposal in the NOPR to discontinue considering affiliate abuse as a separate ''prong'' of the market-based rate analysis and instead codify in the Commission's regulations in § 35.39 an explicit requirement that any seller with market-based rate authority must comply with the affiliate restrictions. This will address affiliate abuse by requiring that the conditions set forth in the regulations be satisfied on an ongoing basis as a condition of obtaining and retaining market-based rate authority. Included in the regulations will be a provision expressly prohibiting power sales between a franchised public utility with captive customers and any market-regulated power sales affiliates without first receiving Commission authorization for the transaction under section 205 of the FPA. Also included in the regulations will be the requirements that have previously been known as the market-based rate ''code of conduct,'' as those requirements have been revised in this Final Rule.

468. Additionally, although we do not adopt the proposal to require that, as a condition of receiving market-based rate authority, sellers must adopt the MBR tariff (included as Appendix A to the NOPR), we do adopt a set of standard tariff provisions that we will require each seller to include in its market-based rate tariff, including a provision requiring the seller to comply with, among other things, the affiliate restrictions in the regulations. We further adopt the proposal that failure to satisfy the conditions set forth in the affiliate restrictions will constitute a tariff violation.

##### b. Definition of ''Captive Customers''

Commission Proposal

469. The Commission stated in the NOPR that, among other things, in the Commission's Final Rule on transactions subject to section 203 of the FPA, the Commission defined the term ''captive customers'' to mean ''any wholesale or retail electric energy customers served under cost-based regulation.''[470] The Commission sought comment on whether the same definition should be used for purposes of this rule.

Comments

470. While a number of commenters support the Commission's proposal to codify the affiliate abuse ''prong'' in the Commission's regulations,[471] they comment that the proposed affiliate abuse restrictions do not do enough to protect retail customers from affiliate abuse.[472] NASUCA argues that affiliate abuse restrictions should be applicable to any affiliate with any retail customers, whether or not the retail affiliate is a ''franchised'' utility, whether or not it has a State-imposed ''service obligation,'' and whether or not its customers are characterized as ''captive.'' NASUCA submits that the Commission should not rely on a State's adoption of a retail access regime for any determination that a customer is not captive. Further, although NASUCA comments that the Commission's proposed definition for ''captive customers'' is an improvement from the text of the proposed regulation (which contains no definition of ''captive customers''), NASUCA suggests it could also invite distinctions turning on the meaning of ''cost-based regulation'' that might cause future uncertainty in some circumstances and a corresponding loss of customer protection.[473]

471. New Jersey Board argues that when customers lack realistic alternatives to purchasing power from their local utility, regardless of a legal right to competitive power suppliers, such customers are still captive. New Jersey Board states that most customers in retail choice states still rely on the provider-of-last-resort for electric service and, thus, are still captive customers.[474] New Jersey Board comments that, due to the relatively young retail choice and deregulation programs in many states, ''it would be premature to declare electric retail choice to be vibrant enough to leave consumer protection from affiliate abuses completely to the marketplace.''[475] New Jersey Board states that, even where there are a few

[468] In the NOPR, the Commission proposed to use the term ''non-regulated power sales affiliate.'' As discussed below, this Final Rule uses the term ''market-regulated power sales affiliate'' instead. ''Market-regulated'' power sales affiliates, for purposes of this rule, refers to sellers that sell at market-based rates rather than cost-based rates. If such sellers are public utilities, technically, they are not unregulated since they must receive market-based rate authority from the Commission and are subject to ongoing oversight by the Commission. See discussion *infra*.

[469] *See generally* APPA/TAPS at 7; 85–86.

[470] *Transactions Subject to FPA section 203,* Order No. 669–A, 71 FR 28422 (May 16, 2006), FERC Stats. & Regs. ¶ 31,214 (2006). *See also Repeal of the Public Utility Holding Company Act of 1935 and Enactment of the Public Utility Holding Company Act of 2005,* Order No. 667–A, 71 FR 28446 (May 16, 2006), FERC Stats. & Regs. ¶ 31, 213 (2006).

[471] New Jersey Board at 3.

[472] NASUCA at 20–30.

[473] NASUCA at 20–30.

[474] New Jersey Board reply comments at 3–4.

[475] *Id.* at 5.

providers that comprise the market, such oligopolies often exhibit the same lack of competition and high prices as are seen in a monopoly market. Thus, affiliate abuse would remain a concern where utilities would be granted market-based rate authority.[476]

472. AARP similarly comments that the proposed definition of ''captive customers'' fails to capture the potential for adverse impacts on retail customers of ''default'' suppliers and thus, the coverage of the Commission's affiliate restrictions should be expanded to prevent customers from bearing the costs of non-regulated marketing affiliates of the public utility they rely on for reliable service.[477]

473. ELCON suggests that ''captive customers'' should be defined as any end-users that do not have real competitive opportunities.[478] It recommends that the Commission adopt a case-specific approach to identifying captive customers to account for the failure of retail competition in many restructured states.

474. A number of other commenters argue that the proposed definition of ''captive customers'' is too broad[479] and would improperly include customers with competitive alternatives. They state that the Commission should clarify that ''captive customers'' does not include customers in states with retail choice.[480] Duke recommends that the Commission define ''captive customer'' as ''any electric energy customer that cannot choose an alternative energy supplier.''[481] Duke adds that initial commenters, such as ELCON, provide no support for their assertion that state retail access programs do not generate effective competition and that most provider-of-last-resort customers are actually captive.

475. Ameren comments that while there are sellers with market-based rate authority that have no captive wholesale customers for energy, but do have a cost-based rate schedule for reactive power supply, the fact that a seller has wholesale customers under a single cost-based rate for reactive power should not render the entity a seller with ''captive customers'' and therefore, subject to the affiliate restrictions.[482] It states that such a seller would have no ability to transfer benefits from its ''captive customers'' (customers taking reactive power services at cost-based rates) to subsidize its unregulated market-based rate sales, given the different products at issue and the restrictions of the cost-based rates for reactive power.

476. APPA/TAPS submit that the definition of ''captive customers'' should include wholesale transmission customers captive to the transmission provider's system.[483] APPA/TAPS state that affiliate abuse not only raises costs to wholesale customers, it can also harm competition such as through cross-subsidization that provides the seller with an unfair competitive advantage. Therefore, APPA/TAPS state that wholesale transmission customers captive to the transmission provider's system are particularly vulnerable to this kind of competitive harm and should be included in the definition of ''captive customers'' in the regulations.[484]

477. EEI responds to APPA/TAPS' comment by stating that it is ''completely unnecessary'' to include transmission dependent utilities in the definition of captive customers since Order No. 888 already provides sufficient protections for transmission customers. Additionally, EEI replies that transmission dependent utilities are like customers with retail choice who have chosen to stay under cost-based rates while other transmission customers have broader options. EEI responds that the Commission does not currently consider such customers captive and there is no reason to change this policy.[485]

Commission Determination

478. The Commission adopts the NOPR proposal to define ''captive customers'' as ''any wholesale or retail electric energy customers served under cost-based regulation.''

479. The Commission clarifies in response to several comments that the definition of ''captive customers'' does not include those customers who have retail choice, *i.e.* the ability to select a retail supplier based on the rates, terms and conditions of service offered. Retail customers who choose to be served under cost-based rates but have the ability, by virtue of State law, to choose one retail supplier over another, are not considered to be under ''cost-based regulation'' and therefore are not ''captive.''

480. As the Commission has explained, retail customers in retail choice states who choose to buy power from their local utility at cost-based rates as part of that utility's provider-of-last-resort obligation are not considered captive customers because, although they may choose not to do so, they have the ability to take service from a different supplier whose rates are set by the marketplace. In other words, they are not served under cost-based regulation, since that term indicates a regulatory regime in which retail choice is not available.[486] On the other hand, in a regulatory regime in which retail customers have no ability to choose a supplier, they are considered captive because they must purchase from the local utility pursuant to cost-based rates set by a State or local regulatory authority.[487] Therefore, with this clarification, the Commission will adopt the definition of ''captive customers'' proposed in the NOPR and clarifies, that, as the Commission did in Order No. 669–A, we will include the definition of captive customers in the regulations. Regarding wholesale customers, sellers should continue to explain why, if they have wholesale customers, those customers are not captive.

481. We note that it is not the role of this Commission to evaluate the success or failure of a State's retail choice program including whether sufficient choices are available for customers inclined to choose a different supplier. In this regard, the states are best equipped to make such a determination and, if necessary, modify or otherwise revise their retail access programs as they deem appropriate. Further, to the extent a retail customer in a retail choice state elects to be served by its local utility under provider-of-last-resort obligations, the State or local rate setting authority, in determining just and reasonable cost-based retail rates, would in most circumstances be able to review the prudence of affiliate purchased power costs and disallow pass-through of costs incurred as a result of an affiliate undue preference.

482. We also decline to include transmission customers in the definition of ''captive customers'' for purposes of market-based rates. We agree with EEI that the Commission's open access

[476] *Id.*

[477] AARP at 10–11.

[478] ELCON at 2, 7–8.

[479] Ameren at 11–14; Allegheny at 12–13; EEI at 44; FirstEnergy at 13; Duke at 4, 32; and Duquesne at 4.

[480] Constellation argues that customers are not to be considered ''captive'' and a seller is therefore not considered a franchised public utility when a retail choice program is in place for the public utility's retail customers. Constellation at 4.

[481] Duke at 32–36. Duke reply comments at 22–23.

[482] Ameren at 12.

[483] APPA/TAPS at 7, 86–87.

[484] *Id.* at 86–87.

[485] EEI reply comments at 35–36.

[486] *Duquesne Light Holdings, Inc.*, 117 FERC ¶ 61,326 at P 38 (2006).

[487] Where a utility has captive retail customers, but industrial customers have retail choice, we would consider that utility to have captive customers because the retail residential customers are captive.

policies protect transmission customers from the exercise of vertical market power. In this regard, we note that the Commission recently issued Order No. 890, which revised the *pro forma* OATT to ensure that it achieves its original purpose of remedying undue discrimination. Order No. 890 provided greater clarity regarding the requirements of the *pro forma* OATT and greater transparency in the rules applicable to the planning and use of the transmission system, in order to reduce opportunities for the exercise of undue discrimination, make undue discrimination easier to detect, and facilitate the Commission's enforcement of the tariff.

483. In response to Ameren's comments that a seller with wholesale customers under a single cost-based rate for reactive power should not be considered a seller with ''captive customers'' subject to the affiliate restrictions, we agree that such customers are not captive for purposes of market-based rates. The concerns underlying the affiliate restrictions do not apply to sales of reactive power because those sales are typically either made to transmission providers so that the transmission provider can satisfy its obligation to provide reactive power or made by the transmission provider under its applicable OATT.

c. Definition of ''Non-Regulated Power Sales Affiliate''

Commission Proposal

484. Proposed § 35.36(a)(6) defined ''non-regulated power sales affiliate'' as ''any non-traditional power seller affiliate, including a power marketer, exempt wholesale generator, qualifying facility or other power seller affiliate, whose power sales are not regulated on a cost basis under the FPA.''

Comments

485. A number of commenters seek clarification and modification of the Commission's proposed definition of ''non-regulated power sales affiliate.''

486. Southern requests clarification that a franchised public utility does not become a non-regulated power sales affiliate simply because it may make some wholesale sales under market-based rate authority.

487. SoCal Edison argues that the Commission offers no explanation for including Qualifying Facilities (QFs) in the definition of ''non-regulated power sales affiliate.'' It states that the proposed definition of non-regulated power sales affiliate would subject QFs that may not have market-based rate authority to the code of conduct. It states that the NOPR proposal would constitute a departure from traditional PURPA implementation and from the Commission's recently revised regulations reaffirming that QF contracts created pursuant to a statutory regulatory authority's implementation of PURPA are exempt from review under sections 205 and 206 of the FPA.[488] PG&E asserts that the Commission should clarify the meaning of ''non-regulated power sales affiliate'' so that it does not encompass all affiliates such as parent companies or the natural gas LDC function of the regulated, franchised utility.[489]

488. Xcel states that it is not clear whether the following result was intended, but the definition arguably could cover a ''traditional'' utility with a franchised retail service territory that had converted all of its wholesale sales from cost-based to market-based rates. According to Xcel, not all utilities will be selling at cost-based rates at wholesale, even though they may still be doing so at retail in franchised service territories.[490] Xcel does not believe that it would be reasonable to exclude from the definition of ''non-regulated power sales affiliate'' a utility that serves retail customers under a franchised service territory. Xcel also comments that the Commission should allow a waiver provision for utilities' subsidiaries or affiliates to be treated under the Commission's affiliate sales rules as affiliated utilities rather than as ''non-regulated power sales affiliates.''[491] Xcel believes that the proposed definition would generally serve to demarcate affiliates that should be treated as regulated from those that should be treated as non-regulated under the Commission's affiliate rules but states that it is not desirable or beneficial to draw a completely bright line between the two. Xcel states that some flexibility may be beneficial for both utilities and their customers and the Commission should not foreclose innovative structures by adopting hard and fast rules.[492]

489. NASUCA also suggests revisions to this definition, out of concern that several of the terms used (non-regulated, non-traditional, regulated on a cost basis) are vague, inaccurate and unnecessary.[493] NASUCA suggests that the term be renamed ''power sales affiliate with market-based rates'' and defined as ''any power seller affiliate utility, including a power marketer, exempt wholesale generator, qualifying facility or other power seller affiliate, with market-based rates authorized under these rules or Commission orders.''[494]

Commission Determination

490. The Commission will modify the definition of ''non-regulated power sales affiliate,'' and change the term to ''market-regulated power sales affiliate.''[495] In response to various commenters, we clarify that this definition is intended to apply only to non-franchised power sales affiliates (whose power sales are not regulated on a cost basis under the FPA, *e.g.*, affiliates whose power sales are made at market-based rates) of franchised public utilities. Additionally, while we recognize that we have used the term ''non-regulated'' in the past, we believe that ''market-regulated'' is a more appropriate description for the entities we intend to capture in this definition. Accordingly, in this Final Rule, we revise the definition of ''market-regulated power sales affiliate'' to mean ''any power seller affiliate other than a franchised public utility, including a power marketer, exempt wholesale generator, qualifying facility or other power seller affiliate, whose power sales are regulated in whole or in part at market-based rates.'' Because the revised definition includes only non-franchised public utilities, it does not apply to a franchised public utility that makes some sales at market-based rates.[496]

491. Xcel posits a somewhat different scenario under which it believes that a franchised public utility would fall within the definition of ''non-regulated power sales affiliate,'' namely, if such utility makes no wholesale sales that are regulated on a cost basis (making only wholesale sales at market-based rates) but serves retail customers under a franchised service territory. With the revision to the definition of ''market-regulated power sales affiliate'' that we adopt here, such a utility would not fall within the definition of ''market-regulated power sales affiliate'' since it has a franchised service territory.

492. In addition, we note that the Commission has historically placed affiliate restrictions only on the

[488] SoCal Edison at 4–6.

[489] PG&E at 14–21.

[490] Xcel at 15.

[491] *Id.*

[492] *Id.* at 16.

[493] NASUCA at 30.

[494] *Id.* at 30.

[495] NOPR at Proposed Regulations at 18 CFR 35.36(a)(6). We adopt this regulation at 18 CFR 35.36(a)(7).

[496] However, under the standards of conduct, a wholesale merchant function that engages in such sales must function independently of the utility's transmission function. 18 CFR 358(d)(3) and 18 CFR 358.4(a)(1).

relationship between a franchised public utility with captive customers and any affiliated market-regulated power sales affiliate. Nevertheless, we believe that there may be circumstances in which it also would be appropriate to impose similar restrictions on the relationship of two affiliated franchised public utilities where one of the affiliates has captive customers and one does not have captive customers. In such a case, there is a potential for the transfer of benefits from the captive customers of the first franchised utility to the benefit of the second franchised utility and ultimately to the joint stockholders of the two affiliated franchised public utilities. Commenters in the instant proceeding did not address the potential for affiliate abuse in this situation (*i.e.*, between a franchised public utility with captive customers and an affiliated franchised public utility without captive customers). Accordingly, we do not generically impose the affiliate restrictions on such relationships but will evaluate whether to impose the affiliate restrictions in such situations on a case-by-case basis.

493. However, to avoid confusion between references to a ''franchised public utility with captive customers'' and a ''franchised public utility without captive customers'' we will revise the definition of ''franchised public utility'' in § 35.36(a)(5) to remove the reference to captive customers. Accordingly, ''franchised public utility'' will be defined as ''a public utility with a franchised service obligation under State law.'' Further, we will revise other sections of the affiliate restrictions to specifically use the term ''franchised public utility with captive customers'' to clarify when the affiliate restrictions apply.

494. Additionally, not all qualifying facilities are necessarily included in the proposed definition of ''market-regulated power sales affiliate.'' Only those qualifying facilities whose market-based rate sales fall under the Commission's jurisdiction would fall within the definition of ''market-regulated power sales affiliate.'' To the extent that some of a qualifying facility's sales are regulated under the FPA, even if other sales are regulated by the states, such a qualifying facility would be considered a market-regulated power sales affiliate by virtue of its FPA jurisdictional sales.

495. Additionally, the Commission clarifies that the definition of ''market-regulated power sales affiliate'' does not encompass all affiliates such as parent companies or the natural gas LDC function of the regulated franchised utility; rather, it only includes non-franchised, power sales affiliates (sellers) that sell power in whole or in part at market based rates, and not an affiliated service company or others who are not authorized to make sales of power.

d. Other Definitions

In the NOPR, the Commission proposed to adopt a restriction on affiliate sales of electric energy, whereby no wholesale sale of electric energy could be made between a public utility seller with a franchised service territory and a non-regulated power sales affiliate without first receiving Commission authorization under FPA section 205. This restriction would be a condition of obtaining and retaining market-based rate authority, and a failure to satisfy that condition would be a violation of the seller's market-based rate tariff.[497]

Comments

496. Constellation proposes that the language in the proposed affiliate sales restriction provision be amended to use the defined term ''franchised public utility'' by replacing the phrase ''public utility Seller with a franchised service territory'' with ''Seller that is a franchised public utility.'' Constellation submits that this change would make clear that the affiliate restrictions apply only if the seller is affiliated with a public utility that has captive customers, which it states appears to be the Commission's intent.[498]

497. FirstEnergy proposes that a definition of franchised service territory be added to the regulations to clarify that the affiliate sales restriction would only apply to transactions involving public utilities with captive retail customers, and would not apply in areas in which there is retail choice.[499]

Commission Determination

498. The Commission's intent was that the affiliate sales restriction in proposed § 35.39(a) (now § 35.39(b)) would apply where a utility with a franchised service territory with captive customers proposes to make wholesale sales at market-based rates to a market-regulated power sales affiliate, or vice versa. Accordingly, we will revise § 35.39(a) (now § 35.39(b)) to replace ''public utility Seller with a franchised service territory'' with ''franchised public utility with captive customers.'' In light of this clarification, we do not believe it necessary to add a definition of franchised service territory to the regulations, as proposed by FirstEnergy.

[497] NOPR at P 108.

[498] Constellation at 13–17.

[499] *See, e.g.*, FirstEnergy at 12–13.

e. Treating Merging Companies as Affiliates

Commission Proposal

499. In the NOPR, the Commission noted that, for purposes of affiliate abuse, companies proposing to merge are considered affiliates under their market-based rate tariffs while their proposed merger is pending, and sought comments regarding at what point the Commission should consider two non-affiliates as merging partners.[500]

Comments

500. PG&E comments that affiliate sales regulations should not apply to contracts that pre-date the announcement of a merger. PG&E states that the Commission should allow merging companies sufficient time (*e.g.*, 30 days) after the announcement of a merger before enforcing the affiliate sales regulations in order to give the merging companies time to acquire the necessary information and documents to prevent a company from being held responsible for activities of the merging company that it has no knowledge of or control over.[501]

Commission Determination

501. The Commission will continue to require that, for purposes of affiliate abuse, companies proposing to merge will be treated as affiliates under their market-based rate tariffs while their proposed merger is pending.[502] The Commission will adopt the proposal to use the date a merger is announced as the triggering event for considering two non-affiliates as merging partners. In this regard, we reject PG&E's proposal that the Commission allow an additional 30 days after an announced merger to begin treating, for the purpose of affiliate abuse, merging partners as affiliates. With the extensive discussions, negotiations and review that precede the formal announcement of plans to merge, there is sufficient time for companies to acquire the necessary information and documents related to the proposed merger, particularly given that utilities are on notice of our policy in this regard.

502. The Commission clarifies that the requirement that merging companies

[500] NOPR at P 116.

[501] PG&E at 14–21.

[502] *Cinergy, Inc.,* 74 FERC ¶ 61,281 (1996); *Consolidated Edison Energy, Inc.,* 83 FERC ¶ 61,236 at 62,034 (1998); *Central and South West Services, Inc.,* 82 FERC ¶ 61,101 at 61,103 (1998); *Delmarva Power & Light Company,* 76 FERC ¶ 61,331 at 62,582 (1996) (''[T]he self-interest of two merger partners converge sufficiently, even before they complete the merger, to compromise the market discipline inherent in arm's-length bargaining that serves as the primary protection against reciprocal dealing.'').

be treated as affiliates while the proposed merger is pending only applies prospectively from the date the merger is announced and does not apply to any contracts entered into that pre-date the announcement of the merger.[503] However, in the case of an umbrella agreement that pre-dates the announcement of the merger, any transactions under such umbrella agreement that are entered into on or after the date the merger is announced would be subject to the affiliate restrictions. Further, if an announced merger does not go forward, the affiliate restrictions will cease to apply as of the date the announcement is made that the merger will not go forward.

f. Treating Energy/Asset Managers as Affiliates

Commission Proposal

503. In the NOPR, the Commission proposed that unaffiliated entities that engage in energy/asset management of generation on behalf of a franchised public utility with captive customers be bound by the same affiliate restrictions as those imposed on the franchised public utility and the non-regulated power sales affiliates.[504] The Commission recognized that there has been an increased range of activities engaged in by asset or energy managers.[505] The Commission noted that although asset managers can provide valuable services and benefit consumers and the marketplace, such relationships also could result in transactions harmful to captive customers.[506] Accordingly, the Commission proposed that an entity managing generation for the franchised public utility should be subject to the same affiliate restrictions as the franchised public utility (*e.g.*, restrictions on affiliate sales and information sharing). The Commission referenced a settlement in which Enforcement staff alleged that an affiliated power marketer acting as an asset manager for three generation-owning affiliates violated § 214 of the FPA.[507] As a result, if a company is managing generation assets for the franchised public utility, such entity would be subject to the same information sharing provision as the franchised public utility with regard to information shared with non-regulated affiliates, such as power marketers and power producers.[508] Similarly, asset managers of a non-regulated affiliate's generation assets would be subject to the same affiliate restrictions as the market-regulated power sales affiliate, including the information sharing provision.[509]

Comments

504. Morgan Stanley comments that unaffiliated asset and energy managers should not be treated as affiliates of owners of the managed portfolios and that it would be overly inclusive for the Commission to adopt a presumption of control that would treat the energy manager as a franchised utility for purposes of the affiliate abuse rules.[510] Financial Companies argue that the Commission should not apply the affiliate abuse restrictions generically to all unaffiliated energy managers that provide management services to a franchised utility or its affiliates. Rather, the Commission should evaluate applicability of the affiliate abuse restrictions on a case-by-case basis.[511]

505. Allegheny claims that the Commission failed to consider the costs to customers, which are likely to be substantial through the loss of efficiencies by treating asset managers as affiliates.[512] Allegheny claims that there will be higher costs because: (1) The affiliated asset manager will need to pass added costs on to the franchised utility; (2) if the affiliated asset manager cannot pass on costs, it may no longer provide the service and the utility may need to set up duplicative asset management capability, resulting in higher costs; or (3) the franchised utility will need to hire a third-party asset manager, presumably more expensive.[513] Constellation makes a similar argument about the substantial costs and reduction of efficiencies by discouraging energy/asset management agreements.[514]

506. EPSA states that it opposes the Commission's proposal to treat asset managers as affiliates. It submits that asset managers are not legally affiliates of the companies with which they have a contract. If the basis for the proposal to treat asset managers as affiliates is for transparency purposes, EPSA says that all such contracts and transactions with asset managers are already reportable under the change in status final rule.[515]

507. Alliance Power Marketing argues that by imposing affiliate abuse restrictions on entities acting on behalf of a regulated public utility or its non-regulated affiliates, the Commission seeks to alter the fundamental principle of responsibility and liability of the regulated entity by making the third-party also directly accountable, thus blurring the lines of accountability. Furthermore, a critical element in applying affiliate abuse restrictions to entities' action on behalf of generation owners lies in having a stake in the outcome rather than just considering some direct or indirect control. Alliance Power Marketing asserts that evaluating control over the outcome as the threshold for asset managers could sweep up many entities, such as RTOs/ISOs, governmental and cooperative entities, that could have jurisdictional and practical ramifications.[516]

508. A number of other commenters oppose the Commission's proposal to treat unaffiliated energy/asset managers as part of the franchised public utility. They argue that the current code of conduct already provides the protections sought by such a proposal and the Commission fails to explain the need for such expanded regulation.[517] Furthermore, they submit that such proposal does not consider the additional costs to consumers through lost efficiencies.[518]

509. PG&E argues that the Commission proposal to consider ''entities acting on behalf of and for the benefit of [the utility/affiliate]'' as part of the utility/affiliate itself is unnecessary and overly broad.[519]

510. Indianapolis P&L does not oppose the Commission's proposal to treat asset managers as affiliates for the limited purposes of the code of conduct, standards of conduct or inter-affiliate transaction issues, but it states that the Commission should not treat unaffiliated asset managers as affiliates when determining how much generating

[503] This is consistent with the standards of conduct, which require transmission providers to post information concerning potential merger partners as affiliates within seven days after the potential merger is announced. 18 CFR 358.4(b)(3)(v).

[504] NOPR at P 117, 130, 131.

[505] *Id.* at P 124 citing Kevin Heslin, A few thoughts on the industry: Ideas from session at Globalcon, Energy User News, July 1, 2002, at 12 (Noting that prior to deregulation, ''an energy manager had relatively straightforward tasks: Understanding applicable tariffs, evaluating the possible installation of energy conservation measures (ECMs), and considering whether to install on-site generation'' but that ''now, an energy manager has to be conversant with a far greater number of issues'' such as complex legal issues and financial instruments like derivatives.)

[506] *Id.*

[507] *Id.* at P 124 (citing *Cleco Corp.,* 104 FERC 61,125 (2003) *(Cleco)).*

[508] NOPR at P 130.

[509] *Id.* at P 131.

[510] Morgan Stanley at 9.

[511] Financial Companies at 11–12.

[512] Allegheny at 14–15.

[513] Allegheny at 15.

[514] Constellation at 6.

[515] EPSA at 28–32.

[516] Alliance Power Marketing at 17–37.

[517] Allegheny Energy Companies at 10–16; PG&E at 14–21.

[518] Allegheny Energy Companies at 10–16.

[519] PG&E at 14–21.

capacity should be attributed to a generation asset owner.[520]

511. Financial Companies and Morgan Stanley both state in their reply comments that the Commission should not impose affiliate restrictions on unaffiliated energy managers, as the Commission provides no basis for such requirement[521] and no evidence that energy managers can engage in cross-subsidization of unregulated affiliates.[522]

Commission Determination

512. From the various comments submitted it is apparent that our proposal has created confusion as to our intent with regard to the treatment of energy/asset managers under the proposed affiliate restrictions. Accordingly, we clarify and simplify our approach, as discussed below.

513. The Commission is concerned that there exists the potential for a franchised public utility with captive customers to interact with a market-regulated power sales affiliate in ways that transfer benefits to the affiliate and its stockholders to the detriment of the captive customers. Therefore, the Commission has adopted certain affiliate restrictions to protect the captive customers and, in this Final Rule, is codifying those restrictions in our regulations. To that end, we make clear that such utilities may not use anyone, including energy/asset managers, to circumvent the affiliate restrictions (*e.g.*, independent functioning and information sharing prohibitions). Accordingly, we adopt and codify in our regulations at § 35.39(c)(1) and 35.39(g) an explicit prohibition on using third-party entities to circumvent otherwise applicable affiliate restrictions.

514. We note that energy/asset managers provide a variety of services for franchised public utilities and market-regulated power sales affiliates, including, but not limited to, operating generation plants (sometimes under tolling agreements), acting as billing agents, bundling transmission and power for customers, and scheduling transactions. However, regardless of the relationships and duties of an energy/asset manager to a franchised public utility or its non-regulated affiliate, the energy/asset manager may not act as a conduit to circumvent the affiliate restrictions.[523]

515. This approach is consistent with past Commission orders that have identified the potential that affiliated exempt wholesale generators or qualifying facilities could serve as a conduit for providing below-cost services to an affiliated power marketer at the expense of captive customers of the public utility operating companies and imposed restrictions to prevent this.[524]

516. Although several commenters assert that the costs of asset management will increase as a result of requiring asset managers to observe the affiliate restrictions, they did not provide any examples of why the costs would increase. The Commission notes that under this Final Rule, all asset managers are not required to observe the affiliate restrictions, only those asset managers which control or market generation of the franchised public utility with captive customers or a market-regulated power sales affiliate of a franchised public utility with captive customers. In those instances, the need to protect captive customers outweighs any generalized assertions of increased cost.

517. We note that to the extent that a franchised public utility with captive customers and one or more of its non-regulated marketing affiliates obtains the services of the same energy/asset manager, such an arrangement would create opportunities to harm captive customers depending on how the energy/asset manager is structured. For example, without internal separation between the energy/asset managers' regulated and non-regulated businesses, there would exist opportunities to harm captive customers.

g. Cooperatives

Comments

518. Suez/Chevron asks the Commission to clarify that jurisdictional utilities organized as cooperatives are not exempt from the affiliate abuse rules and that all jurisdictional public utilities with captive customers, including utilities organized as cooperatives, must comply with the affiliate abuse rules.[525]

519. El Paso E&P argues that it would appear that the proposed affiliate restrictions would apply to power sales at market-based rates made by G&T cooperatives to their State-regulated member distribution cooperatives. It states that based on the definition of a ''franchised public utility'' as ''a public utility with a franchised service obligation under State law and that has captive customers,'' distribution cooperatives that are granted franchised service territories by State regulatory agencies would be included in this definition. El Paso E&P asserts that a G&T cooperative with authority to sell power at market-based rates would be defined as a non-regulated power seller and, accordingly, sales made by a G&T cooperative at market-based rates to its affiliated member distribution cooperatives would, under the proposed regulations, be required to comply with the requirements of the rule.[526]

520. However, El Paso E&P argues that the Commission has previously stated that affiliate abuse is not a concern for cooperatives owned by other cooperatives because the cooperatives' ratepayers are its members. El Paso E&P alleges that the Commission has never sufficiently explained the basis for its prior statements. According to El Paso E&P, the Commission's prior statements are based on the findings in *Hinson Power*[527] that lack of concern with the potential for affiliate abuse is premised on the absence of captive customers that would be subject to the exercise of market power. El Paso submits that the fact that ratepayers of the distribution cooperative are also members of such cooperatives should not alleviate the Commission's concern about potential affiliate abuse issues. El Paso E&P claims that industrial customers of distribution cooperatives with franchised service territories are captive to service from the generation and transmission and distribution cooperatives that serve them and are in need of protection from the Commission to ensure that they are charged just and reasonable rates.[528]

521. NRECA submits that El Paso misreads the proposed regulations by classifying distribution cooperatives as a ''public utility Seller'' under the proposed regulations and NRECA comments that it is not aware of any distribution cooperatives that would be classified as ''public utility Sellers'' thus triggering the restriction on affiliate sales without first receiving Commission approval. NRECA states that nearly all distribution cooperatives are not regulated as public utilities under the FPA because they either have Rural Electrification Act (REA) financing or sell less than 4 million

[520] Indianapolis P&L at 7–10.

[521] Morgan Stanley reply comments at 14.

[522] Financial Companies reply comments at 6.

[523] The Commission is adopting 18 CFR 35.39(g) which prohibits a franchised public utility with captive customers and a market-regulated power sales affiliate from using anyone as a conduit to circumvent any of the affiliate restrictions, including the affiliate sales restriction and the information sharing provision.

[524] *Southern Company Services, Inc.*, 72 FERC ¶ 61,324 at 62,408 (1995).

[525] Suez/Chevron at 10–12.

[526] El Paso E&P at 4–9.

[527] *Hinson Power Company*, 72 FERC ¶ 61,190 (1995).

[528] El Paso E&P at 4–9.

MWh per year and thus do not qualify as a ''public utility'' under section 201(f) of the FPA. Furthermore, NRECA comments that very few distribution cooperatives sell any electricity for resale. Thus, they would not need to obtain market-based rate authority under section 205 even if they were not relieved of that obligation by section 201(f).[529] NRECA also comments that the Commission has explained the reasoning behind not requiring cooperatives to comply with the affiliate abuse requirements by stating that ''in the case of a cooperative, the cooperative's members are both the ratepayers and the shareholders, and thus there is no potential danger of shifting benefits from one to another.'' [530]

522. El Paso E&P responds that NRECA incorrectly interprets the scope of the proposed affiliate restriction and that NRECA ignores the definition of ''franchised public utility'' as ''a public utility with a franchised service obligation under State law and that has captive customers.'' El Paso E&P submits that this definition clearly includes distribution cooperatives. El Paso E&P further replies that the fact that distribution cooperatives are not ''public utilities'' regulated by the Commission is irrelevant because the Commission is not proposing to regulate sales by such distribution cooperatives. Rather, it is proposing to regulate wholesale sales by the generation and transmission cooperatives to their member distribution cooperatives. Therefore, El Paso E&P argues, the Commission should clarify the regulations to ensure that generation and transmission cooperatives are covered under the affiliate restrictions.[531]

523. El Paso E&P also responds that NRECA's attempt to divorce a generation and transmission cooperative's market-based rate sales to its distribution cooperative members from the distribution cooperative's sales to captive customers ignores the cooperative structure. It states that a generation and transmission cooperative is comprised of its member distribution cooperatives and both the generation and transmission and distribution cooperatives act in concert in connection with sales to industrial customers.[532] El Paso E&P also submits that NRECA's argument suggests that the Commission has no jurisdiction over sales to State-regulated franchised public utilities that are not cooperatives.[533] According to El Paso E&P, the captive customers of distribution cooperatives are in need of the same protection from the Commission notwithstanding that the distribution cooperatives are regulated by the states.[534]

524. El Paso E&P also states that wholesale electric sales approved by the Commission must be passed through at the retail level. Thus, El Paso E&P states that it is not sufficient to suggest that the Commission need not be concerned because the distribution cooperatives' rates are subject to State regulation.[535] Finally, El Paso E&P responds that NRECA cannot seek the protection of this Commission when its members are purchasers of power, and then claim its members should be exempt from scrutiny when they are sellers to captive customers such as El Paso E&P. It asserts that captive customers of generation and transmission and their member distribution cooperatives are in need of protection.[536]

Commission Determination

525. FPA section 201(f) specifically exempts from the Commission's regulation under Part II of the FPA, except as specifically provided, electric cooperatives that receive REA financing or sell less than 4 million megawatt hours of electricity per year.[537] Thus, such electric cooperatives are not considered public utilities under the FPA and our market-based rate regulations do not apply to those electric cooperatives. Further, with respect to distribution-only cooperatives, they either do not meet the ''public utility'' definition because they do not own or operate facilities used for wholesale sales or transmission in interstate commerce or, if they do own or operate such facilities, they are exempted from Part II regulation by virtue of FPA section 201(f). In this regard, we note that NRECA states that it is unaware of any distribution cooperatives in the United States that would be ''public utility Sellers'' under the proposed regulations.[538] Such a cooperative would not be subject to the affiliate restrictions in the proposed regulations at § 35.39.

526. For electric cooperatives that are public utility sellers and not exempted from public utility regulation by FPA section 201(f), as discussed above, the Commission will continue to treat such electric cooperatives as not subject to the Commission's affiliate abuse restrictions, based on a finding that transactions of an electric cooperative with its members do not present dangers of affiliate abuse through self-dealing. Even if an electric cooperative is not statutorily exempted from our regulation under Part II of the FPA, we conclude that a waiver of § 35.39 is appropriate. As the Commission has previously explained, ''affiliate abuse takes place when the affiliated public utility and the affiliated power marketer transact in ways that result in a transfer of benefits from the affiliated public utility (and its ratepayers) to the affiliated power marketer (and its shareholders).'' [539] However, as the Commission has previously stated in many market-based rate orders over the years,[540] where a cooperative is involved, the cooperative's members are both the ratepayers and the shareholders. Any profits earned by the cooperative will enure to the benefit of the cooperative's ratepayers. Therefore, we have found that there is no potential danger of shifting benefits from the ratepayers to the shareholders.[541]

527. Finally, we agree with NRECA's argument that the issue that El Paso E&P discusses in its comments is not a concern that can be addressed through affiliate restrictions in market-based rates, but is rather more of a concern of discrimination in the allocation of benefits and burdens among retail ratepayers. The Commission does not possess jurisdiction to review a distribution cooperative's retail rates; that issue falls under State law. Moreover, El Paso E&P's argument that wholesale electric sales approved by the Commission must be passed through at the retail level is misplaced. As the courts have previously held, State commissions are not precluded from reviewing the prudence of a company's purchasing decisions, and may disallow pass-through of wholesale purchase costs unless the purchaser had no legal right to refuse to make a particular purchase.[542]

[529] NRECA supplemental reply comments at 5–6.

[530] NRECA supplemental reply comments at 9.

[531] El Paso E&P answer to reply comments at 2–3.

[532] *Id.* at 3.

[533] *Id.*

[534] *Id.* at 4.

[535] *Id.*

[536] *Id.* at 5.

[537] 16 U.S.C. 824(e)–(f) (2006).

[538] NRECA reply comments at 5.

[539] *Heartland Energy Services, Inc.,* 68 FERC ¶ 61,223 at 62,062 (1994).

[540] *Hinson Power Company,* 72 FERC ¶ 61,190 (1995). *See also, e.g., People's Electric Corp.,* 84 FERC ¶ 61,215 at 62,042 (1998) (application raised no issues of affiliate abuse because the seller was operated by a cooperative whose ratepayers were also its owners); *Old Dominion Electric Cooperative,* 81 FERC ¶ 61,044 at 61,236 (1997).

[541] *Old Dominion Electric Cooperative,* 81 FERC ¶ 61,044 at 61,236 (1997).

[542] *Arkansas Power & Light Co.* v. *Missouri Public Service Commission,* 829 F.2d 1444 at 1451–52 (8th Cir. 1987). *See also Pike County Light & Power* v.

528. Therefore, for the reasons stated above, the Commission will continue to follow its current precedent and find that electric cooperatives that are public utility sellers and not exempted from public utility regulation by FPA § 201(f) are not subject to the Commission's affiliate abuse requirements.

2. Power Sales Restrictions

Commission Proposal

529. In the NOPR the Commission proposed to continue the policy of reviewing power sales transactions between regulated and ''non-regulated'' affiliates under section 205 of the FPA. This policy means, among other things, that a general grant of market-based rate authority does not apply to affiliate sales between a regulated and a non-regulated affiliate, absent express authorization by the Commission.

530. The Commission proposed to amend the regulations to include a provision expressly prohibiting power sales between a franchised public utility [543] and any of its non-regulated power sales affiliates without first receiving authorization for the transaction under section 205 of the FPA.

531. Additionally, although it did not propose to codify the requirement in the regulatory text, the Commission proposed that sellers seeking authorization to engage in affiliate transactions will continue to be obligated to provide evidence as to whether there are captive customers that would trigger the application of the affiliate restrictions. The Commission stated that if the Commission finds, based on the evidence provided by the seller, that the seller has no captive customers, the affiliate restrictions in the regulations would not apply.

532. The Commission proposed to continue its prior approach for determining what types of affiliate sales transactions are permissible and the criteria that should be used to make those decisions, including evaluation of the *Allegheny* and *Edgar* criteria.[544] Although it did not propose to codify a safe harbor provision in the regulations, the Commission noted that when affiliates participate in a competitive solicitation process, application of the *Allegheny* criteria would constitute a safe harbor that affiliate abuse conditions are satisfied in a transaction between a franchised public utility and its affiliates. The Commission emphasized, however, that using a competitive solicitation is not the only way to address concerns that an affiliate transaction does not pose undue preference concerns.[545]

533. The Commission said it continues to believe that tying the price of an affiliate transaction to an established, relevant market price or index such as in an RTO or ISO is acceptable benchmark evidence and mitigates affiliate abuse concerns so long as that benchmark price or index reflects the market price where the affiliate transaction occurs. The Commission proposed to allow affiliate transactions based on a non-RTO price index only if the index fulfills the requirements of the November 19 Price Index Order [546] for eligibility for use in jurisdictional tariffs. The Commission sought comment on whether evidence other than competitive solicitations, RTO price or non-RTO price indices, or benchmarks described in the NOPR should be accepted in an application for authority to engage in market-based affiliate power sales. In addition, the Commission proposed to consider two merging partners as affiliates as of the date a merger is announced, and sought comments on this proposal (or whether to use the date the § 203 application is filed with the Commission, or another time). The Commission also proposed that unaffiliated entities that engage in energy/asset management of generation on behalf of a franchised public utility or non-regulated utility be bound to comply with the same affiliate restrictions as those imposed on the franchised public utility and the non-regulated power sales affiliate.

534. The Commission said it continues to believe that tying the price of an affiliate transaction to an established, relevant market price or index such as in an RTO or ISO is acceptable benchmark evidence and mitigates affiliate abuse concerns so long as that benchmark price or index reflects the market price where the affiliate transaction occurs. The Commission proposed to allow affiliate transactions based on a non-RTO price index only if the index fulfills the requirements of the November 19 Price Index Order [547] for eligibility for use in jurisdictional tariffs. The Commission sought comment on whether evidence other than competitive solicitations, RTO price or non-RTO price indices, or benchmarks described in the NOPR should be accepted in an application for authority to engage in market-based affiliate power sales. In addition, the Commission proposed to consider two merging partners as affiliates as of the date a merger is announced, and sought comments on this proposal (or whether to use the date the § 203 application is filed with the Commission, or another time). The Commission also proposed that unaffiliated entities that engage in energy/asset management of generation on behalf of a franchised public utility or non-regulated utility be bound to comply with the same affiliate restrictions as those imposed on the franchised public utility and the non-regulated power sales affiliate.

Comments

535. Industrial Customers urge the Commission to recognize that when an affiliate transaction has been subject to a State-approved process, separate section 205 approvals for such transactions should not be required. If, however, the Commission does maintain the section 205 approval, ''the imprimatur of State commission approval should create a rebuttable presumption that the transaction is just and reasonable.'' [548] NASUCA comments that the Commission should not assume the reasonableness of all affiliate sales under contracts with

*Pennsylvania Public Utility Commission,* 465 A.2d 735 at 737–78 (1983); *Nantahala Power & Light Co.* v. *Thornburg,* 476 U.S. 953 at 965–67 (1986); *Mississippi Power & Light Co.* v. *Mississippi ex rel. Moore,* 487 U.S. 354 at 369 (1988).

[543] As proposed in the NOPR, the term ''franchised public utility'' was defined as ''a public utility with a franchised service obligation under state law and that has captive customers.'' As set forth below, to avoid confusion between references to a franchised public utility with captive customers and one without, we revise the proposed regulations to delete the reference to customers in the definition and to specifically use the term ''franchised public utility with captive customers'' to clarify when the affiliate restrictions apply.

[544] *Boston Edison Company Re: Edgar Electric Energy Co.*, 55 FERC ¶ 61,382 (1991) (*Edgar*), describing three types of evidence that can be used to show that an affiliate power sales transaction is above suspicion ensuring that the market is not distorted and captive ratepayers are protected: (1) Evidence of direct head-to-head competition between the affiliate and competing unaffiliated suppliers in a formal solicitation or informal negotiation process; (2) evidence of the prices non-affiliated buyers were willing to pay for similar services from the affiliate; or (3) benchmark evidence that shows the prices, terms, and conditions of sales made by non-affiliated sellers. *Allegheny Energy Supply Company, LLC*, 108 FERC ¶ 61,082 (2004) (*Allegheny*), stating four guidelines that help the Commission determine if a competitive solicitation process satisfies the *Edgar* criteria: (1) It is transparent; (2) products are well defined; (3) bids are evaluated comparably with no advantage to affiliates; and (4) it is designed and evaluated by an independent entity.

[545] Although our focus and discussion in this rule is affiliate abuse with respect to affiliates that sell at market-based rates, affiliate concerns also arise with respect to affiliate sales at cost-based rates. See, *e.g.*, *Duke Energy Corp. and Cinergy Corp.*, 113 FERC ¶ 61,297 at P 113–116 (2005), *reh'g denied*, 118 FERC ¶ 61,077 (2007).

[546] *Order Regarding Future Monitoring of Voluntary Price Formation, Use of Price Indices In Jurisdictional Tariffs, and Closing Certain Tariff Dockets*, 109 FERC ¶ 61,184 (2004) (November 19 Price Index Order).

[547] *Id.*

[548] Industrial Customers at 16–18.

prices linked to spot markets or other auction results.[549]

536. Other commenters urge the Commission to clarify that, while requests for proposals consistent with the *Allegheny* and *Edgar* standards and affiliate sales based on market index prices constitute a safe harbor for affiliate abuse, those should not be the only safe harbors.[550] The Commission should state it is willing to consider other information and evidence, including affiliate sales reviewed and authorized by a State regulatory agency, as safe harbors as well.[551]

537. New Jersey Board disagrees with comments that the Commission should consider State approval of affiliate sales as a safe harbor and responds that the Commission should assure that affiliate abuse does not take place and not ignore affiliate sales based on actions and oversight by State commissions.[552]

538. State AGs and Advocates oppose the Commission's proposal to find affiliate sales of wholesale power just and reasonable if such sales are made through an auction that reflects certain guidelines such as those set forth in Edgar and Allegheny. Instead, State AGs and Consumer Advocates state that the Commission should develop behavioral market power tests that apply to all market structures and that each auction should be assessed separately and evaluated on the merits of the proposal.[553]

539. Industrial Customers oppose the Commission's proposal to rely on an RTO/ISO benchmark price or index to mitigate affiliate abuse concerns and argues that tying an affiliate transaction to a price index should not allow utilities to escape scrutiny.[554]

Commission Determination

540. The Commission adopts the proposal to continue its approach for determining what types of affiliate transactions are permissible and the criteria used to make those decisions. Although we are not codifying a safe harbor in our regulations, when affiliates participate in a competitive solicitation process for power sales, we will consider proper application of the *Allegheny* guidelines to constitute a safe harbor that the affiliate abuse concerns are satisfied in a transaction between a franchised public utility with captive customers and its non-regulated power sales affiliate. The Commission will consider proposed competitive solicitations on a case-by-case basis. We again emphasize that using a competitive solicitation by applying the *Allegheny* and *Edgar* guidelines is not the only way an affiliate transaction can address our concerns that the transaction does not pose undue preference concerns. We will consider other approaches on a case-by-case basis. Also, to the extent a seller is not bound by the affiliate restrictions because neither the seller nor the buyer has captive customers, we find that the *Edgar* principles do not apply and the seller does not need to make a filing with regard to a proposed competitive solicitation.[555]

541. A number of commenters urge the Commission to find that a State-approved solicitation process creates a rebuttable presumption that an affiliate transaction satisfies the Commission's affiliate abuse concerns. The Commission will consider a State-approved process as evidence in its consideration as to whether our affiliate abuse concerns have been adequately addressed, but the Commission will not treat a State-approved process as creating a rebuttable presumption that our affiliate abuse concerns have been addressed. In this regard, the Commission has a responsibility under section 205 of the FPA to ensure that all jurisdictional rates charged are just and reasonable and not unduly discriminatory or preferential. While a State-approved solicitation process may provide evidence that the wholesale rates proposed as a result of that process are just and reasonable and do not involve any undue discrimination or preference, we do not believe it is appropriate to create a rebuttable presumption.

542. Further, the Commission will continue to allow an established, relevant market price or index such as in an RTO or ISO to be used as a benchmark for the reasonableness of the price of an affiliate transaction. In this regard, we disagree with commenters that relying on such prices or indices allows utilities to escape Commission scrutiny. Such an index is acceptable benchmark evidence and mitigates affiliate abuse concerns so long as that benchmark price or index reflects the market price where the affiliate transaction occurs (*i.e.*, is a relevant index).[556] The Commission previously stated that the added protections in structured markets with central commitment and dispatch and market monitoring and mitigation (such as RTOs/ISOs) generally result in a market where prices are transparent.[557]

543. In addition, while the Commission has found in the past that certain non-RTO price indices are acceptable indicators of market prices, we continue to recognize that price indices at thinly traded points can be subject to manipulation and are otherwise not good measures of market prices as discussed in the Price Index Policy Statement [558] and November 19 Price Index Order. Therefore, the Commission will allow affiliate transactions based on a non-RTO price index only if the index fulfills the requirements of the November 19 Price Index Order for eligibility for use in jurisdictional tariffs and reflects the market price where the affiliate transaction occurs (*i.e.*, is a relevant index).[559]

3. Market-Based Rate Affiliate Restrictions (Formerly Code of Conduct) for Affiliate Transactions Involving Power Sales and Brokering, Non-Power Goods and Services and Information Sharing

Commission Proposal

544. The Commission stated in the NOPR that it continues to believe that a code of conduct is necessary to protect captive customers from the potential for affiliate abuse. In light of the repeal of the Public Utility Holding Company Act of 1935 [560] and the fact that holding company systems may have franchised public utility members with captive customers as well as numerous non-regulated power sales affiliates that engage in non-power goods and services transactions with each other, the Commission stated that it is important to have in place restrictions that preclude transferring captive customer benefits to stockholders through a company's non-regulated power sales business. Therefore, the Commission stated its belief that it is appropriate to condition all market-based rate authorizations, including authorizations

[549] NASUCA at 20–29.

[550] Indianapolis P&L at 7–10.

[551] FirstEnergy at 12–27.

[552] New Jersey Board reply comments at 6.

[553] State AGs and Advocates reply comments at 12–13.

[554] Industrial Customers at 16–18.

[555] *Southern California Edison Co.*, 109 FERC ¶ 61,086 at P 35 (2004) (noting that Commission's concern in cases involving sales to affiliates has been the potential for cross-subsidization at the expense of the public utility's captive customers).

[556] *Brownsville*, 111 FERC ¶ 61,398 at P 10 (2005). *See also Portland General Elec. Co.*, 96 FERC ¶ 61,093 at 61,378 (2001); *FirstEnergy Trading*, 88 FERC ¶ 61,067 at 61,156 (1999).

[557] April 14 Order, 107 FERC ¶ 61,018 at P 189.

[558] *Policy Statement on Natural Gas and Electric Price Indices*, 104 FERC ¶ 61,121 (2003) (Price Index Policy Statement).

[559] *November 19 Price Index Order*, 109 FERC ¶ 61,184 at P 40–69.

[560] *Repeal of the Public Utility Holding Company Act of 1935 and Enactment of the Public Utility Holding Company Act of 2005*, Order No. 667, 70 FR 75592 (Dec. 20, 2005), FERC Stats. & Regs. Regulations Preambles 2001–2005 ¶ 31,197 (2005).

for sellers within holding companies, on the seller abiding by a code of conduct for sales of non-power goods and services and services between power sales affiliates. In addition, the Commission stated that greater uniformity and consistency in the codes of conduct is appropriate and, therefore, proposed to adopt a uniform code of conduct to govern the relationship between franchised public utilities with captive customers and their ''non-regulated'' affiliates, *i.e.*, affiliates whose power sales are not regulated on a cost basis under the FPA. The Commission proposed to codify such affiliate restrictions in the regulations and to require that, as a condition of receiving market-based rate authority, franchised public utility sellers with captive customers comply with these restrictions. The Commission proposed that the failure to satisfy the conditions set forth in the affiliate restrictions will constitute a tariff violation.

545. The Commission sought comments on this proposal and on whether the specific affiliate restrictions proposed in the NOPR are sufficient to protect captive customers. In particular, the Commission sought comments on what changes, if any, should be adopted.

a. Uniform Code of Conduct/Affiliate Restrictions—Generally

Comments

546. Some commenters support codifying the code of conduct affiliate restrictions in the regulations and comment that it will lead to consistent codes of conduct across all sellers, thus creating greater transparency, and will aid the Commission's enforcement efforts.[561] ELCON argues that the ability of large utility holding companies with one foot in ''competition'' and one foot in ''regulation'' creates a myriad of potential problems.[562] Several State agencies and consumer commenters generally support the proposal to codify uniform code of conduct restrictions in the Commission's regulations.[563] NASUCA comments that the separation of function requirements should apply to any affiliate with retail customers, not just to affiliates who are franchised public utilities.[564]

547. FP&L, however, does not believe it is unduly preferential to have different codes of conduct.[565] Indianapolis P&L argues that a single tariff/code of conduct does not make sense for diversified energy companies with geographically widespread operations.[566]

548. FP&L states that the Commission should include in the regulatory text the statement that the affiliate restrictions are waived where a seller demonstrates that there are no captive customers.[567] EEI states that utilities already found not to have captive customers because of retail choice should be grandfathered and should not have to request waiver of the code of conduct again.[568]

Commission Determination

549. The Commission will adopt the proposed affiliate restrictions with certain modifications and clarifications. These restrictions govern the separation of functions, the sharing of market information, sales of non-power goods or services, and power brokering. The Commission will require that, as a condition of receiving and retaining market-based rate authority, sellers comply with these affiliate restrictions unless otherwise permitted by Commission rule or order. As discussed herein, these affiliate restrictions govern the relationship between franchised public utilities with captive customers and their ''market-regulated'' affiliates, *i.e.*, affiliates whose power sales are regulated in whole or in part on a market-based rate basis.

550. Failure to satisfy the conditions set forth in the affiliate restrictions will constitute a violation of the market-based rate tariff. As discussed in greater detail below, the Commission agrees with many of the commenters that the requirements and exceptions in the affiliate restrictions should follow those requirements and exceptions codified in the standards of conduct, where applicable.[569] The Commission believes that modeling these restrictions and the exceptions to those restrictions on the standards of conduct will lead to greater consistency and transparency and a greater understanding of permissible activities.

551. The Commission clarifies that any sellers that have previously demonstrated and been found not to have captive customers, and therefore have received a waiver of the market-based rate code of conduct requirement in whole or in part, will not be required to request another waiver of the associated affiliate restrictions. However, those sellers are still under the obligation to report to the Commission any changes in status that may affect the basis on which the Commission relied in granting their waiver, consistent with the requirements of Order No. 652.[570] Additionally, those sellers also will be required to meet the requirements necessary to maintain their market-based rate authority when they file their regularly scheduled updated market power analyses. As a result, they will be required to demonstrate that they continue to lack captive customers in order to support a continued waiver of the affiliate restrictions in the regulations. Sellers will also need to explain why any wholesale customers are not captive, as explained above.

552. In response to FP&L and EEI, because we clarify in this Final Rule that, where a seller demonstrates and the Commission agrees that it has no captive customers, the affiliate restrictions will not apply, the Commission does not believe it is necessary to include in the regulatory text a provision stating that the affiliate restrictions are waived where a seller demonstrates and the Commission agrees that it has no captive customers.

[561] ELCON and EPSA support codifying a uniform code of conduct. ELCON at 2 and EPSA at 28.

[562] ELCON at 3.

[563] *Id.* at 6–10, New Jersey Board at 2, and NRECA at 11.

[564] NASUCA at 20–29.

[565] FP&L at 3.

[566] Indianapolis P&L at 12.

[567] FP&L at 5–6.

[568] EEI at 43; EEI reply comments at 35.

[569] On November 17, 2006, the D.C. Circuit vacated the Order No. 2004 standards of conduct orders as they related to natural gas pipelines and remanded the orders to the Commission. *National Fuel Gas Supply Corporation* v. *FERC*, 468 F.3d 831 (D.C. Cir. 2006). The court found that the rulemaking record did not support the Commission's attempt to extend the standards of conduct beyond pipelines' relationships with their marketing affiliates to also govern pipelines' relationships with numerous non-marketing affiliates, such as producers, gatherers, and local distribution companies (which Order No. 2004 defined as ''energy affiliates''). In response to this decision, the Commission issued an interim rule on January 9, 2007 reinstating those provisions of Order No. 2004 that were not specifically appealed to the D.C. Circuit. *Standards of Conduct for Transmission Providers*, Order No. 690, 72 FR 2427 (Jan. 19, 2007); FERC Stats. & Regs. ¶ 31,237 (Jan. 9, 2007); *order on reh'g, Standards of Conduct for Transmission Providers*, Order No. 690–A, 72 FR 14235 (Mar. 27, 2007); FERC Stats. & Regs. ¶ 31,243 (2007). On January 18, 2007, the Commission issued a Notice of Proposed Rulemaking proposing to make the changes in the Interim Rule permanent and seeking comment on whether the restrictions covering relationships between electric transmission providers and non-marketing affiliates that are engaged in energy transactions should be retained. *Standards of Conduct for Transmission Providers*, Notice of Proposed Rulemaking, 72 FR 3958 (Jan. 29, 2007), FERC Stats. & Regs. ¶ 32,611 (2007).

[570] *Reporting Requirement For Changes in Status For Public Utilities with Market-Based Rate Authority*, Order No. 652, 70 FR 8253 (Feb. 18, 2005), FERC Stats. & Regs., Regulations Preambles January 2001–December 2005 ¶ 31,175, *order on reh'g*, Order No. 652–A, 111 FERC ¶ 61,413 (2005).

b. Exceptions to the Independent Functioning Requirement

Commission Proposal Regarding Separation of Employees and Shared Employees

553. In the NOPR, the Commission proposed regulatory language in § 35.39(b)(2) (now § 35.39(c)(2)) codifying the independent functioning requirement. Specifically, the Commission stated, to the maximum extent practical, the employees of a non-regulated power sales affiliate will operate separately from the employees of any affiliated franchised public utility.

554. The Commission did not propose to include any exceptions to the independent functioning requirements. However, the Commission invited commenters to propose additions to, substitutions for or elimination of the proposed affiliate restrictions.[571]

Comments

555. A number of commenters request that the Commission modify the affiliate restrictions to adopt some of the requirements and exceptions consistent with those codified in Order No. 2004, such as allowing the sharing of senior officers and members of the board of directors, field and maintenance employees and support employees. According to EPSA, the affiliate restrictions should provide specifically for permissible sharing of officers (not just sharing of support personnel) between a franchised public utility and a non-regulated power sales affiliate. EPSA notes that Order No. 2004 allows for shared officers as long as they do not direct, organize or execute day-to-day business transactions.[572]

556. Duke comments that treatment of shared employees under the affiliate restrictions should follow the obligations adopted in the standards of conduct. For example, Duke urges the Commission to allow the sharing of officers and directors.[573] Additionally, Avista states that the proposed affiliate restrictions should distinguish between operational and non-operational employees.[574]

557. PG&E urges the Commission to clarify which employees cannot be shared. PG&E states that prohibiting employees involved in general operation of generation facilities, who lack control over generation availability, from being shared would be overly broad and unduly restrictive.[575] PPL similarly requests clarification of which employees would be deemed ''shared employees'' under the affiliate restrictions.[576]

558. NiSource requests that the Commission create an exception to allow the sharing between operational employees of the franchised public utility and its non-regulated sales affiliates of any information necessary to maintain the safe and reliable operation of the bulk power system, similar to the exception in the standards of conduct at § 358.5(b)(8) of the Commission's regulations.[577]

559. EEI and FirstEnergy also request that the independent functioning requirement and information sharing restrictions in the proposed affiliate restrictions should have an exception for sharing employees and market information for emergency circumstances affecting system reliability.[578]

560. On the other hand, Morgan Stanley urges the Commission not to adopt a blanket exception to the affiliate restrictions for emergency situations because the commenters' proposal regarding what constitutes an ''emergency'' is vague and leaves too much discretion to the individual sellers. Additionally, Morgan Stanley explains that communications with an affiliate during an emergency may not adequately address an emergency; sharing information with all sellers in the market would provide a better foundation to deal with any emergency.[579]

Commission Determination

561. The Commission will revise the independent functioning requirement of the affiliate restrictions to include exceptions relating to permissibly shared senior officers and members of boards of directors, shared support personnel, and shared field and maintenance personnel. With regard to permissibly shared individuals, the Commission will impose a ''no-conduit rule'' similar to that in the standards of conduct.[580] Under the no conduit rule, to be codified at § 35.39(g), a permissibly shared employee is prohibited from acting as a conduit for disclosing market information to employees, officers or directors that are not shared.

562. The Commission agrees that a franchised public utility with captive customers and its market-regulated power sales affiliates should be permitted to share senior officers and members of the board of directors to conduct corporate governance functions, and to take advantage of the efficiencies of corporate integration.[581] Therefore, the Commission is adopting an exception at § 35.39(c)(2)(d) that permits a franchised public utility with captive customers and its market-regulated power sales affiliate to share senior officers and members of the board of directors. Specifically, a franchised public utility with captive customers and its market-regulated power sales affiliate may share senior officers and members of boards of directors provided that these individuals do not participate in directing, operating or executing generation or market functions.[582] In addition, to prevent permissibly shared senior officers or members of the board of directors from using their preferential access to market information to harm captive customers, consistent with the no-conduit rule codified at § 35.39(g), the permissibly shared senior officers and directors may not act as a conduit to provide market information to non-shared employees of the franchised public utility with captive customers or its market-regulated power sales affiliates.

563. The Commission also agrees that it is appropriate to codify an exception that permits the sharing of support employees between the franchised public utility with captive customers and its market-regulated power sales affiliates comparable to the standards of conduct exception, likewise subject to the no-conduit rule.[583]

564. The Commission rejects Duke's request that the Commission include a non-exhaustive list of examples of permissible shared support employees within the body of § 35.39. However, we clarify that the types of permissibly shared support employees under the standards of conduct are the types of permissibly shared support employees that will be allowed under the affiliate restrictions in § 35.39(c)(2)(c). Such employees include those in legal, accounting, human resources, travel and information technology.[584] Because permissibly shared employees may have access to market information, they are

[571] NOPR at P 132.

[572] EPSA at 31.

[573] Duke at 43. *See also* EPSA at 31; FirstEnergy at 26.

[574] Avista at 7–10.

[575] PG&E at 14–21.

[576] PPL reply comments at 21–22.

[577] NiSource at 1.

[578] EEI at 44; FirstEnergy at 22.

[579] Morgan Stanley reply comments at 7–8.

[580] 18 CFR 358.4(a)(5) (shared senior officers and directors); 18 CFR 358.5(b)(7) (general ''no conduit'' rule covering employees).

[581] Order No. 2004–A at P 134.

[582] *See* 18 CFR 358.4(a)(5).

[583] Order No. 2004 at P 99–101.

[584] *Id.* at P 96.

prohibited from acting as a conduit to provide market information to employees of the franchised public utility with captive customers and the market-regulated power sales affiliates that are not permitted to be shared.

565. The Commission also agrees to codify an exception to the independent functioning requirement to allow franchised public utilities with captive customers and their market-regulated power sales affiliates to share field and maintenance employees. Field and maintenance employees perform purely manual, technical or mechanical duties that are supportive in nature and do not have planning or direct operational responsibilities. Such employees would likely be part of shared work crews to do repair or maintenance work on facilities or equipment. Examples of activities that may be performed by shared field and maintenance employees are reading meters, replacing parts in generators, restringing transmission lines, snow removal or maintaining roadways. The key is that these employees do not also perform operational duties.[585] A field or maintenance employee cannot be shared if that employee also engages in marketing activities, makes decisions that would affect marketing activities, or controls generation. We also consider the immediate supervisors of field and maintenance employees as permissibly shared employees so long as they cannot control operations, *e.g.* restrict or shut down generation facilities.[586]

566. The Commission agrees with commenters that allowing the sharing of field and maintenance employees between a franchised public utility with captive customers and its market-regulated power sales affiliates is unlikely to harm captive customers, provided that those shared employees do not act as a conduit for sharing market information with employees of the franchised public utility with captive customers or market-regulated power sales affiliates. The permissibly shared field and maintenance employees are required to observe the no-conduit rule.

567. The Commission disagrees with NiSource that a broad exception to the independent functioning and information sharing requirement is needed for the reliable operation of the bulk power system. Such an exception would be so broad that it would swallow the rule and create too many opportunities for shared employees to take actions to harm captive customers based upon their decision making authority and control over the bulk power system. The Commission will consider requests for waiver of the affiliate restriction requirements to address the specific circumstances of the operation of a bulk power system and notes that, subsequent to NiSource's comments, the Commission granted a partial waiver of the code of conduct requirements for the situation described in NiSource's comments.[587]

568. While the Commission does not agree with NiSource's proposal for a broad exception to the affiliate restrictions for everyday operations of the bulk power system, the Commission does agree with EEI and FirstEnergy that the affiliate restrictions should contain an exception related to emergency circumstances affecting system reliability. As such, the Commission will adopt an exception to the independent functioning requirement and the information sharing restrictions for emergency circumstances affecting system reliability comparable to the exception in the standards of conduct.[588] The exception will apply to both the independent functioning requirements and the information sharing restrictions. The Commission will modify proposed § 35.39(d) (to be codified at § 35.39(c)(2)(b)) to add a provision that states that, notwithstanding any other restrictions in this section, in emergency circumstances affecting system reliability, a market-regulated power sales affiliate and the franchised public utility with captive customers may take the necessary steps to keep the bulk power system in operation. The relaxation of the requirements during system emergencies is intended to ensure that the franchised public utility with captive customers and market-regulated power sales affiliate(s) can maintain reliability of the power grid. However, the market-regulated power sales affiliate or the franchised public utility must report to the Commission and disclose to the public on its Web site each emergency that resulted in any deviation from the restrictions of § 35.39(c)(2)(b), within 24 hours of such deviation. Reports to the Commission of emergency deviations under the affiliate restrictions in § 35.39(c)(2)(b) will be made using the ''EY'' docket prefix.

569. The Commission and the public will be able to monitor the frequency of these emergency deviations through the reporting requirement. Members of the public can seek redress from the Commission if they feel that the exception has been abused or used improperly.

c. Information Sharing Restrictions

Commission Proposal

570. In the NOPR, the Commission proposed regulatory language to codify the information sharing restrictions. Specifically, the Commission proposed that the regulations provide that all market information sharing between a franchised public utility and a non-regulated power sales affiliate will be disclosed simultaneously to the public. This includes, but is not limited to any communication concerning power or transmission business, present or future, positive or negative, concrete or potential.[589]

Comments

571. Ameren supports codification of the information sharing restrictions, but recommends that proposed § 35.39(c) be revised to allow permissibly shared senior officers and directors to receive market information so long as they do not act as a conduit to improperly share such information, akin to the standards of conduct.

572. Avista argues that the Commission should allow officers to be shared by affiliates, subject to the no-conduit rule.[590] EEI argues that for corporate governance and accountability purposes, there should be an exception to the information sharing prohibitions for shared senior officers, subject to the no conduit rule.[591]

573. EPSA also asks the Commission to provide a specific time period for the length of time that posted information needs to remain on the Web site.[592]

574. PPL comments that the Commission should clarify which situations would permit deviations from the code of conduct regarding

[585] *Id.* at P 145–146.

[586] *See id.* at P 145–46. As discussed later, such actions would be permitted in emergency circumstance affecting system reliability.

[587] *Northern Indiana Public Service Company and Whiting Clean Energy, Inc.*, 116 FERC ¶ 61,248 (2006). Northern Indiana Public Service Company (NIPSCO) sought a waiver of the code of conduct so that it could perform its duties as a balancing authority. Specifically, NIPSCO wanted the ability to have access to real-time information regarding the amount of energy being delivered to NIPSCO from its affiliate, Whiting Clean Energy, Inc., (Whiting). The Commission granted a partial waiver limited to Whiting providing NIPSCO with the real-time information NIPSCO needed to carry out its responsibilities as a balancing authority in accordance with the requirements of the North American Electric Reliability Council (NERC), NERC approved regional reliability organization and the Midwest Independent Transmission System Operator, Inc. *Id.* at P 13. The Commission also reminded NIPSCO that its employees were prohibited from being a conduit for improperly sharing Whiting's generation information. *Id.*

[588] 18 CFR 358.4(a)(2).

[589] *See* NOPR at P 121, 129.

[590] Avista at 2.

[591] EEI at 44.

[592] EPSA at 31–32.

information sharing. Specifically, it suggests that the Commission adopt, for the affiliate restrictions, the standards of conduct exception that permits the sharing of information to comply with Nuclear Regulatory Commission (NRC) requirements.[593]

575. A number of commenters argue that the Commission should not adopt the two-way information sharing prohibition in the uniform code of conduct because they disagree that a communication from the non-regulated power sales affiliate to the franchised public utility could potentially harm captive customers.[594]

576. Duke notes that while the two-way restriction is consistent with the default code of conduct that the Commission has used since 1999, the Commission has approved many codes of conduct that contain one-way restrictions (*i.e.*, codes that restrict a franchised public utility from sharing marketing information with its non-regulated power sales affiliates, but do not place a similar restriction on a non-regulated power marketer from sharing market information with its affiliated franchised utility). Duke says the Commission has failed to explain the elimination of previously-approved one-way restrictions.[595] It submits that the one-way code of conduct is sufficient to address affiliate abuse concerns and that the two-way code of conduct requirement will impose substantial costs on market-based rate sellers with no discernible benefits.[596] According to Duke, a number of market participants have made important organizational and commercial decisions based on current policies and precedents allowing one-way communications. In the absence of any basis for reversing that policy, Duke submits that the Commission should reconsider its proposal to mandate two-way information sharing restrictions.

577. In addition, Duke argues that only two commenters, EPSA and ELCON, expressed even generalized support for a standardized code of conduct containing the two-way code restriction, but did not address the underlying policy issues of why or how a traditional utility's regulated customers could be harmed if their unregulated affiliate were to share market information with the utility.[597]

578. According to FP&L, the proposed two-way information sharing restriction does not provide any additional protection for captive customers. Rather, such a restriction may place artificial and unnecessary barriers on a company's ability to conduct business.[598] According to FP&L, the two-way restriction proposed in § 35.39(c) (to be codified at § 35.39(d)) concerning the communication of all market information between a franchised public utility and its non-regulated power sales affiliates is unnecessary if sales of capacity and energy between those entities are prohibited under the specific terms of the market-based rate tariff. It submits that, if the Commission nevertheless concludes that a two-way restriction on communications should be adopted, then the final regulations should provide an exception if, in the market-based rate tariff, the non-regulated power sales affiliates have restricted sales to, and purchases from, their franchised public utility affiliate without having received advance Commission approval pursuant to a separate filing under section 205 of the FPA.[599]

579. Similarly, EEI argues that the Commission has not explained how the two-way information sharing prohibition protects captive customers.[600]

Commission Determination

580. The Commission will revise the information sharing prohibitions to adopt certain exceptions. As discussed earlier with regard to the independent functioning requirement, we are creating exceptions to permit shared senior officers and members of a board of directors, as well as to permit shared field and maintenance employees. Permissibly shared employees may share all types of market information. However, the information sharing provision, like all the affiliate restrictions, is subject to the ''no-conduit'' rule that we codify in the regulations. The no-conduit rule allows permissibly shared employees to receive market information so long as they are not conduits for sharing that information with employees that are not permissibly shared. In addition, as also discussed earlier in the independent functioning section, market information may be shared to address emergency circumstances affecting system reliability in order to keep the bulk power system in operation, provided that the subsequent reporting provisions are followed.

581. In response to PPL Companies' concern as to communications relating to nuclear power plants, the Commission clarifies that the types of communications permitted under the standards of conduct for nuclear safety and regulatory requirements are also permitted under the affiliate restrictions.[601] Specifically, the Commission permitted transmission providers to communicate with affiliated and nonaffiliated nuclear power plants to enable the nuclear power plants to comply with the requirements of the NRC as described in the NRC's February 1, 2006 Generic Letter 2006–002, Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power.[602]

582. In response to EPSA's request regarding the specific time period that posted material needs to remain on the Web site, the Commission concludes that it is appropriate to use the requirements set forth regarding OASIS postings in 18 CFR 37.7(b). Specifically, the material must be posted for 90 days and then be retained and made available upon request for download for five years from the date when first posted. The archived material must be available in the same electronic form used as when it was originally posted.

583. The Commission will adopt the two-way information sharing restriction in proposed § 35.39(c) (now § 35.39(d)). The purpose of the affiliate restrictions in § 35.39 is to ensure that franchised public utility sellers with captive customers will not be able to engage in affiliate abuse to the detriment of those captive customers. One way the Commission achieves this is by restricting the sharing of information between a franchised public utility with captive customers and a market-regulated power sales affiliate. The Commission has long required a seller

[593] PPL reply comments at 21–22 citing *Interpretive Order Relating to the Standards of Conduct,* 114 FERC ¶ 61,155 (2006), *order on request for additional clarification,* 115 FERC ¶ 61,202 (2006).

[594] Allegheny Energy Companies' Comments at 3; Duke at 37–40; PG&E at 20, FirstEnergy at 23 and FP&L at 4.

[595] Duke at 38.

[596] Duke reply comments at 20–21.

[597] *Id.* at 20.

[598] FP&L at 4.

[599] *Id.* at 4–5.

[600] EEI at 45.

[601] *Interpretive Order Relating to the Standards of Conduct,* 114 FERC ¶ 61,155 (2006), *order on request for additional clarification,* 115 FERC ¶ 61,202 (2006).

[602] Nuclear Regulatory Commission's Generic Letter 2006–002, Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power. February 1, 2006. OMB Control No.: 3150–0011. Transmission providers may share with affiliates information to operate and maintain the transmission system and information required to maintain interconnected facilities. However, transmission providers may not share transmission or marketing information that would give a transmission provider's marketing or energy affiliates undue preference over a transmission provider's non-affiliated customers in energy markets. 114 FERC ¶ 61,155 (2006).

to address any potential affiliate abuse concerns before receiving Commission authorization to sell at market-based rates. The Commission has previously held that ''[t]here are many ways for the affiliated public utility and the affiliated power marketer to exchange information that would exacerbate affiliate abuse concerns.'' [603] Therefore, the Commission required that the sellers ''ensure that market information is not shared among affiliates.'' [604]

584. The Commission later reaffirmed this in stating the general standards under which it reviews applications for market-based rate authority, including a demonstration by an affiliate that ''there are adequate procedures in place to ensure that market information is not shared between it and the affiliate public utility.'' [605]

585. With regard to Duke's suggestion that we have failed to explain the elimination of the one-way restriction, we will provide the following example of our concern in this regard.

586. One example of how of improper sharing of information could harm captive customers is a circumstance where both a franchised public utility and its market-regulated power sales affiliate are considering whether to bid into an RFP to provide power. If the market-regulated power sales affiliate has absolute freedom to inform its franchised public utility affiliate that it intends to bid into the RFP, including but not limited to the price and quantity it intends to offer, the franchised public utility affiliate has the ability and incentive to use that information to benefit its stockholders at the expense of its captive customers (*e.g.*, by either not bidding into the RFP or doing so at a price above that of its affiliate).

587. While we recognize that some sellers may need to adjust their activities to comply with the two-way information restriction, we do not believe that such adjustments will impose significant costs upon those sellers. Furthermore, as explained above, we believe that the two-way information sharing restriction will provide captive customers a more complete protection from affiliate abuse. We find that any potential cost to sellers is outweighed by the increased protection a two-way information sharing restriction provides to captive customers.

588. Therefore, to ensure that all captive customers are protected from the potential for affiliate abuse, the Commission will adopt the proposed two-way information restriction in § 35.39(d). Any sellers whose activities are currently governed by a code of conduct with a one-way information restriction will be deemed to have adopted a two-way information restriction as of the effective date of this Final Rule.

589. The Commission restates that the affiliate restrictions only apply when captive customers exist; therefore, if the Commission has found that there are no captive customers, then, consistent with § 35.39(b) through (g), the affiliate restrictions, including the prohibition on information sharing, will not apply.

d. Definition of ''Market Information''

Comments

590. Progress Energy urges the Commission to clarify the definition of the term ''market information'' which it argues is arbitrarily broad and may include public as well as non-public market information.[606] SoCal Edison states that the Commission should only prohibit the sharing of non-public market information among a utility and its market-regulated power sales affiliates, as outlined in the standards of conduct.[607] EPSA also asserts that the Commission should clarify that the simultaneous posting requirement should apply to the communication of all non-public market information (not all market information). It notes that Order No. 2004 specifically applies to non-public transmission information, not all transmission information.

Commission Determination

591. The Commission previously explained that ''market information'' includes information on sales or purchases that will not be made (as well as purchases and sales that will be made), as well as any information concerning a utility's power or transmission business—broker-related or not, past, present or future, positive or negative, concrete or potential, significant or slight.[608] In an effort to provide additional clarity and regulatory certainty, we will provide further guidance and adopt and codify in § 35.36(a)(8) the following definition of market information: ''market information means non-public information related to the electric energy and power business including, but not limited to, information regarding sales, cost of production, generator outages, generator heat rates, unconsummated transactions, or historical generator volumes. Market information includes information from either affiliates or non-affiliates.''

592. The Commission clarifies that the definition does not prohibit the disclosure of publicly available information. We find that, because of its very nature of being publicly available to all entities, restrictions on sharing publicly available information are unnecessary. In addition, the definition does not prohibit the sharing of transmission information. The standards of conduct already prevent improper disclosures of non-public transmission information by a transmission provider to its marketing and energy affiliates, which would include both the franchised public utility with captive customers and the market-regulated power sales affiliate.[609]

593. Further, as we have indicated, a principal purpose of the affiliate restrictions is to ensure that the interaction between a franchised public utility and its market-regulated affiliate does not result in harm to the franchised public utility's captive customers. Therefore, we clarify that, as a general matter, the definition of ''market information'' includes information that, if shared between a franchised public utility and a market-regulated affiliate, may result in a detriment to the franchised public utility's captive customers. Therefore, market information includes, but is not limited to, information concerning sales and purchases that will not be made such as in circumstances where parties have discussed a potential contract but no agreement has been reached. In contrast, market information does not include information that would not result in an advantage to the recipient that could be used to the detriment of the franchised public utility's captive customers. For example, a franchised public utility with captive customers and its market-regulated power sales affiliate may share information related to the relocation of the franchised public utility's headquarters, business opportunities outside the United States, general turbine safety information and internal procedures for general maintenance activities (other than scheduling). We clarify that the definition of ''market information'' includes, but is not limited to, written, printed, verbal, audiovisual, or graphic information.

594. We are adding language to the information sharing restriction of § 35.39(d)(1) to make clear that disclosures of market information are

[603] *Heartland Energy Services, Inc.*, 68 FERC ¶ 61,223 (1994).

[604] *Id.*

[605] *LG&E Power Marketing, Inc.*, 68 FERC ¶ 61,247 (1994).

[606] Progress Energy at 36–37.

[607] SoCal Edison at 3–6.

[608] *UtiliCorp United, Inc.*, 75 FERC ¶ 61,168 (1996).

[609] 18 CFR 358.5(a) and (b) (2006).

prohibited, unless simultaneously disclosed to the public, if the information could be used to the detriment of captive customers. For example, if a franchised public utility with captive customers conducts negotiations with an unaffiliated generator to acquire power, but does not reach an agreement, the franchised public utility with captive customers is prohibited from sharing with its market-regulated power sales affiliate any non-public information it acquired through the unsuccessful negotiations unless such information is simultaneously disclosed to the public. Information relating to any other entities' electric energy or power business is also subject to the sharing of market information restriction if such information could be used to the detriment of captive customers. Also subject to the information sharing restriction is information regarding brokering activities, past sales and purchase activities, and the availability or price of inputs to generation such as natural gas supply if such information could be used to the detriment of captive customers. For example, a franchised public utility with captive customers is restricted from disclosing to its market-regulated power sales affiliate any non-public information about a non-affiliated generator's upcoming maintenance or outage schedules or information about the non-affiliated generator's historical generation volumes, unless such information is simultaneously disclosed to the public. In addition, neither the franchised public utility with captive customers nor its market-regulated power sales affiliate may tell the other that it intends to sell power to a third party, including but not limited to the price and quantity it intends to offer, unless such information is simultaneously disclosed to the public. Similarly, a market-regulated power sales affiliate is likewise restricted from telling its franchised public utility affiliate with captive customers about any other business opportunity that it is considering or is undertaking, unless such information is simultaneously disclosed to the public.

e. Sales of Non-Power Goods or Services

Commission Proposal

595. In the NOPR, the Commission proposed regulatory language to codify the requirements governing sales of non-power goods or services. The Commission proposed that sales of any non-power goods or services by a franchised public utility to a market-regulated power sales affiliates will be at the higher of cost or market price, and that sales of any non-power goods or services by a market-regulated power sales affiliate to an affiliated franchised public utility will not be at a price above market.

Comments

596. PG&E argues that, while charging the high of cost or market price may be appropriate for sales of goods, it is ''inoperable and inappropriate'' for sales of services because market prices for sales of service by a third party may be hard to ascertain due to limited providers and that prices from a third party provider will not take into account efficiencies resulting from a utility and its affiliate sharing services.[610] PG&E further comments that charging the higher of cost or market, as proposed, may increase costs for both the utility and the affiliate by discouraging the efficient sharing of services. Therefore, PG&E proposes that instead of charging the higher of cost or market price for non-power services, the Commission should allow a proxy for the market price such as the fully-loaded cost plus a reasonable profit, *e.g.*, five percent.[611]

Commission Determination

597. The Commission will adopt the NOPR proposal to codify the requirement that sales of non-power goods and services by a franchised public utility with captive customers to a market-regulated power sales affiliate be at the higher of cost or market price, unless otherwise authorized by the Commission. This requirement, along with other requirements in the affiliate restrictions, protect a franchised public utility's captive customers against inappropriate cross-subsidization of market-regulated power sales affiliates by ensuring that the utility with captive customers does not recover too little for goods and services that the utility provides to a market-regulated power sales affiliate.[612] We also adopt the NOPR proposal to codify the requirement that sales of any non-power goods or services by a market-regulated power sales affiliate to an affiliated franchised public utility with captive customers will not be at a price above market, unless otherwise authorized by the Commission. This requirement protects a utility's captive customers against inappropriate cross-subsidization of market-regulated power sales affiliates by ensuring that the utility with captive customers does not pay too much for goods and services that the utility receives from a market-regulated power sales affiliate.

598. We note that PG&E fails to provide the Commission with any specific examples of non-power services for which there is no corresponding third-party provider. Therefore, we are not persuaded by PG&E that there is a need or a benefit to changing our precedent on this issue. We will adopt the affiliate restrictions as proposed and require that sales of non-power goods or services by a franchised public utility with captive customers to a market-regulated power sales affiliate be at the higher of cost or market price. Nevertheless, we will address on a case-by-case basis arguments that charging the higher of cost or market for certain sales of non-power services may not be appropriate in a particular case.

f. Service Companies or Parent Companies Acting on Behalf of and for the Benefit of a Franchised Public Utility

Commission Proposal

599. The Commission proposed in the NOPR to treat companies that are acting on behalf of and for the benefit of franchised public utilities with captive customers, for purposes of the affiliate provisions, as that franchised public utility. Likewise, in the case of non-regulated affiliates, the proposed affiliate provisions treat companies that are acting on behalf of and for the benefit of non-regulated affiliates, for purposes of the affiliate provisions, as the non-regulated affiliates.[613]

Comments

600. EEI asks the Commission to clarify that the code of conduct (affiliate restrictions) provisions to be codified in the regulations do not preclude the use of service companies that manage assets for both regulated and unregulated affiliates.[614] EEI submits that the language of proposed § 35.39(b) (now § 35.39(c)) uses ''entities acting on behalf of and for the benefit of a franchised pubic utility (such as entities managing the electric generation assets of the franchised pubic utility)'' whereas the NOPR text reads ''entities acting on behalf of and for the benefit of a franchised public utility (such as service companies and entities managing the generation assets of the franchised pubic utility).'' EEI argues that the treatment of service companies as part of the franchised public utility in the preamble to the NOPR is different from the language in the proposed

[610] PG&E at 20–21.

[611] *Id.* at 21.

[612] *See generally National Grid plc and Keyspan Corp.*, 117 FERC ¶ 61,080 at P 65–66 (2006), *reh'g pending.*

[613] NOPR at 83–84.

[614] EEI at 45–46.

regulation and makes the Commission's intent unclear. It submits that many companies use service companies to provide support activities to the franchised utility and non-regulated affiliates consistent with the no-conduit rule. EEI asks the Commission to clarify that the standardization of the code of conduct is not intended to change this practice. PG&E claims that under a plain reading of the proposed regulation, a parent company that acts on behalf of either the utility or the affiliate will be considered a part of the utility or affiliate, and communication with either entity will be restricted under proposed § 35.39(c) (now § 35.39(d)).[615] It argues that the Commission should only consider a holding company or parent company as an affiliate subject to the information sharing prohibitions if it engages in energy transactions on its own behalf.[616]

601. Southern states that it is unclear how the Commission intends to address and apply the requirements of separation of functions and information sharing in the context of public utility holding companies that have system pooling agreements.[617] Southern recommends the Commission refine the definition of ''non-regulated power sales affiliate'' at least insofar as that term is used in the proposed separation of functions and information sharing provisions to exclude pooled system affiliates of traditional franchised utilities where affiliate interactions and sharing of benefits and burdens of pooled operations are addressed under an arrangement filed and approved under section 205.[618]

602. EEI requests that the Commission clarify that, in circumstances where sales between affiliates have been made in connection with an approved system agreement, such agreements continue to govern.[619] Southern requests that the Final Rule clarify that affiliated operating companies may continue to operate on a pooled basis.[620] Southern states that traditional centralized service company affiliates providing system pooling support services under filed and approved system agreements should not be treated as non-regulated power sales affiliates.[621]

Commission Determination

603. The Commission clarifies that it did not intend to include service companies as ''entities acting on behalf of and for the benefit of a franchised public utility'' for purposes of the separation of functions provision in § 35.39(b) (now § 35.39(c)) to the extent that such service companies do not engage in generation or marketing activities.[622] Although service companies not engaged in generation or marketing activities are not included in the coverage of § 35.39(e), they may not act as a conduit for providing non-public market information between a franchised public utility and a market-regulated power sales affiliate. However, unless otherwise permitted by Commission rule or order, service companies cannot be used to direct, organize or execute generation or marketing activities for both the franchised public utility and the market-regulated power sales affiliate(s). In response to Southern's and EEI's request to clarify that affiliated operating companies may continue to operate as a pool or pursuant to an approved system agreement, nothing in this Final Rule precludes pool operation pursuant to filed tariffs or agreements approved by the Commission and nothing in this rule changes filed system agreements approved by the Commission. To the extent that individual companies enter into new pooling or system agreements, the Commission will continue to review those agreements on a case-by-case basis to ensure that, among other things, affiliate transactions meet the requirements of section 205 of the FPA and otherwise satisfy our affiliate abuse concerns.

*D. Mitigation*

604. In the NOPR, the Commission sought comment on whether the default mitigation adopted in the April 14 Order is appropriate as currently structured. The Commission's current default mitigation rates are as follows: (1) Sales of power of one week or less will be priced at the seller's incremental cost plus a 10 percent adder; (2) sales of power of more than one week but less than one year (sometimes referred to as ''mid-term sales'') will be priced at an embedded cost ''up to'' rate reflecting the costs of the unit or units expected to provide the service; and (3) new contracts for sales of power for one year or more will be priced at a rate not to exceed the embedded cost of service, and the contract will be filed with the Commission for review and approved prior to the commencement of service.[623]

605. In the NOPR, the Commission sought comment on the following four issues that have arisen in implementing cost-based mitigation: (i) The rate methodology for designing cost-based mitigation; (ii) discounting; (iii) protecting customers in mitigated markets; and (iv) sales by mitigated sellers that ''sink'' in unmitigated markets.

1. Cost-Based Rate Methodology

a. Sales of One Week or Less

Commission Proposal

606. The Commission noted that two principal issues concerning rate methodology have arisen in implementing the April 14 Order. The first relates to power sales of one week or less being made at incremental cost plus 10 percent.[624] The Commission noted that sellers have argued that this is a departure from the Commission's historical acceptance of ''up to'' rates for short-term energy sales, including sales of one week or less, and sought comment on whether to continue to apply a default rate for such sales that is tied to incremental cost plus 10 percent. The Commission sought comment as to: (i) Whether there are problems associated with using ''up to'' rates for shorter-term sales and, if so, what are they; (ii) whether the current approach provides utilities a disincentive to offer their power to wholesale customers in their local control area for short-term sales; and (iii) whether an ''up to'' rate adequately mitigates market power for such sales.

[615] PG&E at 16–17.

[616] PG&E at 17.

[617] Southern at 49.

[618] Southern at 50.

[619] EEI at 46–49.

[620] Southern at 44–52. Southern also asks that the Commission revise the affiliate abuse regulations to include a definition of ''pooled system affiliates'' and clarify that the definition of non-regulated power sales affiliate excludes ''pooled system affiliates'' of traditional franchised utilities. Southern states that any definition of ''pooled system affiliates'' should address both existing arrangements (that have been reviewed and approved by the Commission) and prospective arrangements.

[621] Southern at 48–52.

[622] As proposed in the NOPR, the separation of functions provision provided that ''entities acting on behalf of and for the benefit of a franchised public utility (such as entities managing the generation assets of the franchised public utility) are considered part of the franchised public utility.'' In this Final Rule, we modify the parenthetical in that provision to state: ''(such as entities controlling or marketing power from the electrical generation assets of the franchised public utility).'' See 18 CFR 35.39(c)(1).

[623] April 14 Order, 107 FERC ¶ 61,018 at P 151; *see also* NOPR at P 22, 137.

[624] In a number of instances, the NOPR referred to these sales as ''sales of less than one week,'' and a number of commenters likewise used ''sales of less than one week'' in their comments. We clarify that the reference in the NOPR should have been to ''sales of one week or less,'' consistent with the April 14 and July 8 Orders. Accordingly, for purposes of this Final Rule, we use ''sales of one week or less'' even if the commenters used ''sales of less than one week.''

Comments

607. While not opposing the default rate, APPA/TAPS state that as an alternative, sales of one week or less could occur under the traditional ''split the savings'' methodology.[625] APPA/TAPS submit that both of these methods are consistent with the Commission's observation that ''[a]bsent market power, a generator would typically run if it had excess power and could cover its incremental costs plus some return.'' [626]

608. While the Carolina Agencies claim that sales of one week or less should not carry a capacity charge, they concede that a reasonable contribution to the mitigated supplier's fixed costs may be appropriate (*e.g.*, by including a modest adder over the supplier's incremental cost of energy).[627]

609. NRECA and AARP ask the Commission to retain the incremental cost plus 10 percent methodology for mitigating sales of one week or less.[628] NRECA expresses a concern that the Commission's default cost-based rates (for all three products—sales of one week or less; sales of more than one week but less than one year; and sales of one year or longer) may be subject to gaming by larger public utilities, especially because the sellers hold all of the critical data. It asserts that if sellers have too much leeway in choosing which units they will use to calculate their incremental or embedded costs, the default cost-based rates will not provide an effective rate ceiling, and the purpose of the default mitigation will be undermined. NRECA proposes that the Commission require sellers subject to default cost-based rates to submit both pre- and post-approval filings supporting the mitigated cost-based rates for short- and mid-term sales. NRECA suggests that the seller justify its mitigated rates beforehand by demonstrating its incremental costs or embedded costs, as appropriate, and then file after-the-fact quarterly reports of the actual sales and the actual incremental or embedded costs incurred in making these sales.[629] NRECA suggests that this approach would subject mitigated cost-based rate sales to a cost-based formula rate, and therefore to refund, upon Commission review of the quarterly compliance filing.[630]

610. NASUCA urges the Commission to require that all mitigated rates, and any rate discounts, whether for more or less than one year in duration, must be filed and made subject to public scrutiny and Commission review under section 205 of the FPA.[631] NASUCA is concerned that under the NOPR, only rates to be in effect for more than one year are required to be filed publicly in advance and subject to protest, intervention, prior Commission review and revision. It argues, however, that section 205 contains no exception from the filing requirement for sales of less than one year.[632] Given that all new rate schedules and contracts affecting rates must be publicly filed, NASUCA asks the Commission not to reduce section 205's procedural safeguards for sales of less than one year at cost-based rates (*i.e.*, by not requiring that they be subject to prior notice and review).[633]

611. Some commenters oppose the incremental cost plus 10 percent default rate, with several alleging that it deviates from prior Commission precedent without sufficient justification and fails to adequately compensate sellers.[634] Some commenters also allege that such an approach will deter new entry and gives sellers the incentive to sell outside the mitigated market.

612. For example, Westar states that the Commission's reasoning in the July 8 Order which explained that the cost plus 10 percent default rate represents a ''conservative proxy for a reasonable margin available in a competitive market,'' [635] suffers from two fatal flaws. First, the Commission failed to distinguish or even mention *Terra Comfort* wherein, Westar and Duke submit, the Commission found that 10 percent adders provide no contribution to fixed costs, and it rejected the argument that ''utilities routinely forego these margins and sell at 110 percent of incremental cost.'' [636] Second, according to Westar, in adopting this default rate the Commission relied heavily upon an order that applied the formula in an RTO under entirely different circumstances.[637]

613. MidAmerican and Westar note that, in support of the default rate, in the April 14 Order the Commission cited a PJM tariff provision pursuant to which generators dispatched out of economic merit have their bids mitigated to incremental costs plus 10 percent to prevent them from exercising market power and, at the same time, providing revenues which include a margin.[638] MidAmerican and Westar contend that this is merely an example of a mitigation mechanism, not a rationale for a broad-scale default mitigation scheme that ignores years of precedent.[639] They submit that the PJM tariff mitigates bids for a select set of generators. They state that, regardless of the level of their bids, those generators are still paid the market clearing price because only the offer is capped. Further, because PJM's methodology applied this offer cap only to a limited number of hours, MidAmerican and Westar state that sellers were also free to bid above the cap in the majority of the hours of the year.[640] In contrast, MidAmerican and Westar claim that the incremental cost plus 10 percent default rate is an absolute cap on revenues that would apply to all sales of one week or less in length.[641]

614. Although the July 8 Order explained that incremental cost plus 10 percent was a backstop, default rate, and that entities were free to propose alternative mitigation schemes, MidAmerican asserts that this ignores the fact that the Commission has routinely accepted alternative cost-based rates for sales of one week or less. As such, MidAmerican maintains that there is no reason why ''split the savings'' rates, or rates reflecting a demand charge, could not be used as a default rate for mitigated sales of one week or less.[642]

615. Several commenters also argue that the energy-only incremental cost plus 10 percent methodology does not allow for proper recovery of capacity-based costs on sales of one week or less thereby artificially depressing the prices of these short-term sales and possibly deterring new entry.[643] These commenters state that sellers should be

[625] APPA/TAPS at 45–46.

[626] *Id.* (quoting April 14 Order, 107 FERC ¶ 61,018 at P 152).

[627] Carolina Agencies at 11.

[628] NRECA at 30; AARP at 8.

[629] Suez/Chevron voice a similar concern, adding that a true-up provision would also help improve transparency with regard to the cost of mitigated sales for the benefit of state commissions. Suez/Chevron at 13–14.

[630] NRECA at 30–32.

[631] NASUCA at 18–19; NASUCA reply comments at 16–18.

[632] NASUCA at 18 (citing NOPR at P 22).

[633] *Id.* at 18–19.

[634] MidAmerican at 9–11, Westar at 24.

[635] July 8 Order, 108 FERC ¶ 61,026 at P 155.

[636] Westar at 24 (quoting *Terra Comfort Corp.*, 52 FERC ¶ 61,241 at 61,839–40 (1990)); Duke at 8–9, n.9.

[637] Westar at 25 (citing *PJM Interconnection, L.L.C.*, 107 FERC ¶ 61,112, at 61,366 (2004), *order on reh'g, PJM Interconnection, L.L.C.*, 110 FERC ¶ 61,053 (2005)).

[638] April 14 Order, 107 FERC ¶ 61,018 at P 152, n.146.

[639] MidAmerican at 10; Westar at 25.

[640] *Id.*

[641] *Id.*

[642] MidAmerican at 13.

[643] Pinnacle at 10; Ameren at 15; Duke at 8; MidAmerican at 9–11; Westar at 24; Drs. Broehm and Fox-Penner at 15–16; Xcel at 9; Progress Energy at 9; PPL reply comments at 17–18; EEI at 29; NRG at 5, 11.

allowed to recover a contribution to their fixed/capacity costs.

616. Some commenters contend that the default cost-based rates create an incentive to sell outside the mitigated market because they recover less than cost-based rates historically accepted that included a demand charge. However, they assert that setting rates that require buyers to make a reasonable contribution to the seller's fixed costs for the use of the capacity would create an incentive for the seller to make sales within its mitigated control area.[644] Duke and the Oregon Commission add that allowing recovery of capacity-based costs also ensures that wholesale customers bear their fair share of system costs.[645]

617. Several commenters also claim that by artificially depressing short-term sales prices, the default rate transfers wealth from the supplier's retail customers to wholesale customers.[646] Such retail customers, these commenters state, have paid the fully-allocated costs of the system and obtain revenue credits to their costs from the supplier's short-term sales. Where short-term sales are made on a non-interruptible basis, and the incremental cost plus 10 percent rate prices them only at incremental running cost, Progress Energy contends that wholesale purchasers are receiving the benefits of capacity without cost.[647] Progress Energy and EEI submit that retail native load customers, as a result, lose the economic benefits that would otherwise accrue to them through revenue credits from short-term wholesale sales.[648] Wholesale customers charged through an embedded cost-of-service are also harmed, Progress Energy adds, because they lose the economic benefits that would otherwise accrue to them through revenue credits from short-term wholesale sales.[649]

618. Progress Energy and Duke instead favor an ''up to'' cost-based default rate for sales of one week or less.[650] For such sales, Progress Energy supports an ''up to'' rate design flexible enough to allow rates as low as the mitigated seller's incremental costs and as high as 100 percent of the seller's capacity and energy costs. According to Progress Energy, a mitigated seller could choose to make sales as low as its incremental cost when either (1) The unmitigated market price of competing sellers dictates that price, or (2) the mitigated seller needs to sell its excess generation at that price to maintain a minimum generation control margin. Given that there is a short-term market for capacity, Progress Energy asks that the default cost-based rates include a price structure that allows pricing of capacity-only sales.[651]

619. Xcel suggests that the Commission should allow for an even higher emergency price in situations where purchasers need to make a purchase not simply to achieve economic benefits but where the purchaser is capacity deficient. Xcel submits that in such instances, a purchaser plainly obtains a capacity benefit from the purchase of such power. Historically, the Commission has allowed an emergency rate of $100 per MWh for emergency service. Given that gas prices have dramatically increased since that standard rate began to be utilized, Xcel claims that an emergency rate of the higher of cost plus 10 percent or $1,000 per MWh would be appropriate in the present environment.[652]

Commission Determination

620. The Commission will retain the incremental cost plus 10 percent methodology as the default mitigation for sales of one week or less, while continuing to allow sellers to propose alternative cost-based methods of mitigation tailored to their particular circumstances. As discussed more fully below, we clarify that in retaining the incremental cost plus 10 percent methodology as the default mitigation for sales of one week or less we do not otherwise limit a seller's ability to propose different cost-based rates for sales of one week or less.[653]

621. Although a number of commenters suggest that the Commission should adopt a different default cost-based ratemaking methodology for sales of one week or less, they have failed to persuade us that the existing default rate is inappropriate. As the Commission has previously stated, an incremental cost rate that allows a fair recovery of the incremental cost of generating with a 10 percent adder to provide for a margin over incremental cost is reasonable.[654] Incremental costs plus 10 percent represents a conservative proxy for a reasonable rate available in a competitive market.[655] On this basis, we find incremental cost plus 10 percent to be an appropriate default rate. Moreover, we allow sellers the opportunity to design, support, and propose other cost-based rates that they believe are more appropriate for their particular circumstances.

622. Several commenters note that the Commission has permitted various cost-based rate methodologies prior to the April 14 Order, including a split-the-savings formula. These entities express concern that the use of the incremental cost plus 10 percent methodology as the default mitigation rate for sales of one week or less forecloses the possibility of other cost-based pricing methodologies. However, this is not the case. Rather than precluding alternative mitigation proposals, the April 14 Order allows sellers to propose case-specific tailored mitigation, or adopt the default cost-based rate. The April 14 Order described the default mitigation rate as ''a backstop measure'' intended to ensure a just and reasonable rate.[656] The Commission re-emphasized this in its July 8 Order explaining: ''In the instant case, the 10 percent adder is to be used only as a backstop or default measure *in the event that an applicant does not opt to propose its own mitigation.*'' [657]

623. As such, the incremental cost plus 10 percent rate represents a default, cost-based rate to protect customers from the potential exercise of market power and provide sellers regulatory rate certainty by establishing a ''safe harbor.'' Any proposal for alternative cost-based rates will be considered on a case-by-case basis.

624. Further, with regard to including capacity charges in rates for one week or less, a seller may propose to recover such charges and the Commission will consider these charges based on the specific facts and circumstances presented. Rather than ignoring alternative forms of cost-based rates, as some commenters claim, the Commission's policy offers sellers the opportunity to propose such alternatives.

625. Use of the default rate as set forth in the April 14 and July 8 Orders also is not inconsistent with *Terra Comfort,* as some commenters claim. As explained above, contrary to some commenters' allegations, the Commission does not confine mitigated sellers to rates that forego a contribution to fixed/capacity costs. In *Terra Comfort,* the Commission explained that

[644] *See, e.g.,* Duke at 9.

[645] *Id.* at 10; Oregon Commission reply comments at 2.

[646] Westar at 16; Progress Energy at 9; EEI at 33–34; Pinnacle at 10; MidAmerican at 9.

[647] Progress Energy at 9–10.

[648] *Id.* at 10, n.13; EEI at 29.

[649] Progress Energy at 10, n.13.

[650] Progress Energy at 10; Duke at 8.

[651] Progress Energy at 10.

[652] Xcel at 10.

[653] For that matter, we also do not limit a seller's ability to propose and support different cost-based rates for any of the default cost-based rates.

[654] April 14 Order, 107 FERC ¶ 61,018 at P 152.

[655] July 8 Order, 108 FERC ¶ 61,026 at P 155.

[656] April 14 Order, 107 FERC ¶ 61,018 at P 148.

[657] July 8 Order, 108 FERC ¶ 61,026 at P 157 (emphasis added).

''most utilities maintain on file for all services flexible demand charge ceilings designed to reflect a 100-percent contribution to the fixed costs of their facilities.'' [658] The Commission then added that utilities are not obligated to ''forego these margins and sell at 110 percent of incremental costs.'' [659] In the April 14 Order, the Commission, consistent with its holding in *Terra Comfort,* explained that ''as a backstop measure, we will also provide 'default' rates to ensure that wholesale rates do not go into effect, or remain in effect, without assurance that they are just and reasonable.'' [660] Contrary to Duke's assertion that this default rate suggests that sellers do not have economic justification (or need) to recover a share of their fixed/capacity costs in the prices charged for such transactions,[661] the Commission's policy allows ''applicants to propose case-specific mitigation tailored to their particular circumstances that eliminates the ability to exercise market power, or adopt cost-based rates such as the default rates herein.'' [662] The Commission explained in the April 14 Order that ''[p]roposals for alternative mitigation in these circumstances could include cost-based rates or other mitigation that the Commission may deem appropriate.'' [663] Consistent with industry practice and Commission precedent, therefore, where mitigated sellers can properly justify such contributions, they may propose to recover contributions to fixed/capacity costs under the Commission's mitigation policy.

626. Such alternative mitigation has been proposed and accepted. For example, Progress Energy correctly notes that one of its subsidiaries proposed as mitigation—and the Commission approved—a cost-based ''up-to'' capacity charge and a cost-based energy charge for the subsidiary's power sales of less than one year, including sales of one week or less, in the mitigated control area.[664] Progress Energy is correct in observing that this decision was consistent with the Commission's long-standing policy of permitting the pricing of short-term sales at cost-based ''up-to'' capacity charges and cost-based energy charges.[665] Rather than artificially depressing the prices of short-term sales, exacting a wealth transfer, or limiting a seller's ability to respond to market conditions, as Progress suggests, the default cost-based rate for sales of one week or less provides a backstop measure intended to protect customers by ensuring that, in the event a seller loses or relinquishes its market-based rate authority, there is a readily available cost-based rate under which such sellers may choose to transact, and the mitigated seller by establishing a refund floor that provides it with rate certainty.

627. As to some commenters' suggestion that the incremental cost plus 10 percent methodology, and cost-based rates in general, adversely affect retail rates because they exact a wealth transfer from the supplier's retail customers to wholesale customers, the July 8 Order rejected such claims on the ground that they were ''unsupported and speculative.'' [666] Not only do these claims remain unsupported but they suggest that the Commission should allow wholesale rates in excess of a just and reasonable rate. This result would not be just and reasonable. As the Commission stated in the July 8 Order, ''our rate making policy is designed to provide for recovery of prudently incurred costs plus a reasonable return on investment.'' [667] Moreover, the Commission explained that ''the opportunity for the applicants to propose alternative, tailored mitigation measures should allow adequate consideration of the effect on investment and customers.'' [668]

628. We will not adopt Progress Energy's request that the default rate be modified to include a price structure allowing pricing of capacity-only sales. Progress Energy fails to provide adequate justification to provide for such a rate in our default cost-based rates. For example, Progress Energy states that there is a short-term market for capacity-only sales but fails to explain how this market is a power sales market (for which our default cost-based rates apply) rather than an ancillary services market which is not contemplated in the default cost-based power sales rates. Nevertheless, as noted above, a mitigated seller has the opportunity to propose and justify an alternative to the default rate.

629. Similarly, in response to NASUCA's request that the Commission require all mitigated rates and discounts to be filed under section 205 of the FPA, we note that all mitigation proposals must be filed with the Commission for review. These filings are noticed and interested parties are given an opportunity to intervene, comment, or protest the submittal. With regard to discounts, as we explain in the discounting section of this Final Rule, discounts made to customers, like all other rates, are required to be reported in the seller's EQRs.

630. We also note that the Commission stated in the April 14 Order that where a seller proposes to adopt the default cost-based rates (or where it proposes other cost-based rates), it must provide cost support for such rates.[669] The Commission will examine the proposed rates on a case-by-case basis. With regard to sales of one week or less, where the seller fails to provide sufficient cost support, the Commission will direct the seller to submit a compliance filing to provide the formulas and methodology according to which it intends to calculate incremental costs.[670] We note here that, to the extent a seller proposes a cost-based rate formula, we will require the rate formula used be provided for Commission review and such formula included in the cost-based rate tariff including formulas used in calculating incremental cost.

631. The Commission also has set proposed default cost-based rates for hearing when appropriate.[671] We believe that this case-by-case review of proposed default cost-based rates adequately addresses NRECA's and Suez/Chevron's concerns. Moreover, to the extent that an entity contends that a mitigated seller is flowing inappropriate costs through its formula rate, section 206 of the FPA provides a process for filing a complaint.

b. Sales of More Than One Week But Less Than One Year

Commission Proposal

632. In the NOPR, the Commission sought comment on issues related to the design of an ''up to'' cost-based rate. The Commission noted in the NOPR

[658] *Terra Comfort Corp.,* 52 FERC at 61,839.

[659] *Id.*

[660] April 14 Order, 107 FERC ¶ 61,018 at P 148.

[661] Duke at 9 (citing *Terra Comfort,* 52 FERC at 61,839).

[662] April 14 Order, 107 FERC ¶ 61,018 at P 147.

[663] 663 April 14 Order, 107 FERC ¶ 61,018 at n.142.

[664] Carolina Power & Light, 113 FERC ¶ 61,130 at P 23–24 (2005) (citing *Detroit Edison Co.,* 78 FERC ¶ 61,149 (1997) (approving a demand charge for power sales for periods of an hour up to one year); *Illinois Power Co.,* 57 FERC ¶ 61,213, at 61,699–700 (1991) (permitting utilities to include in their rates an amount above incremental costs to provide a contribution to fixed costs)).

[665] Progress Energy at 8–9.

[666] July 8 Order, 108 FERC ¶ 61,026 at P 140, 154.

[667] *Id.* at P 152.

[668] *Id.* at P 154

[669] April 14 Order, 107 FERC ¶ 61,018 at P 208. *See Entergy Services, Inc.,* 115 FERC ¶ 61,260 at P 49 (2006) (accepting cost-based rates based on incremental cost plus 10 percent, noting that filing included the formula and methodology according to which seller intends to calculate incremental costs).

[670] *See, e.g., Aquila, Inc.,* 112 FERC ¶ 61,307 at P 26 (2005); *Oklahoma Gas and Electric Co.,* 114 FERC ¶ 61,297 at P 19 (2006).

[671] *AEP Power Marketing, Inc.,* 112 FERC ¶ 61,047 at P 28 (2005).

that it has allowed significant flexibility in designing ''up to'' rates in the past, and invited comments on whether such flexibility is still warranted. In particular, the Commission noted that there are often disputes over which units are ''most likely to participate'' or ''could participate'' in coordinated sales, and asked if it should continue to allow utilities flexibility in selecting the particular units that form the basis of the ''up to'' rate. If not, the Commission asked which units should form the basis of an ''up to'' rate, and how such a rate should be calculated. In addition, parties were invited to comment on whether a standard rate methodology should be prescribed that would allow a seller to avoid a hearing on this issue. The Commission asked whether a methodology that is based on average costs (both variable and embedded) would allow a seller to avoid a hearing because it eliminates the seller's discretion in designating particular units as ''likely to participate.'' The Commission also inquired as to whether there are other approaches that would accomplish a similar objective.

Comments

i. Selecting the Particular Units That Form the Basis of the ''Up to'' Rate

633. Regarding whether the Commission should continue to allow utilities flexibility in selecting the particular units that form the basis of the ''up to'' rate, EEI argues for flexibility because selection of generating units for these short-terms sales is made with the goal of minimizing the cost-of-service to the utility's native load customers.[672] Several commenters note that the Commission has the ability to verify the validity of the seller's analysis through an audit of the company's records to monitor transactions made under the ''up to'' rates.[673]

634. Pinnacle asks the Commission to establish a stacking methodology that determines default units most likely to run while allowing utilities to propose a different stack based on historical operational sales data. Pinnacle also urges the Commission to clarify that the variable cost for the unit can be defined as the system incremental cost.[674]

635. Other commenters raise concerns with respect to the discretion given to utilities to choose units used to calculate the ceiling.[675] They submit that taking only a small snapshot of certain generating plants to develop cost-based rates will subject buyers to the discretion of sellers possessing market power.

636. APPA/TAPS, the Carolina Agencies and AARP oppose allowing mitigated sellers too much flexibility in designing mitigation methods on the grounds that such an approach would result in market-based rates disguised as cost-based mitigated rates.[676] For mid-term sales, APPA/TAPS and AARP urge the Commission to require a well-supported analysis of the units most likely to provide the service.[677]

637. The Carolina Agencies ask the Commission to consider whether pricing service based on the costs of units ''likely to participate'' is sufficiently rigorous to meet the operative statutory standards. They oppose the ''units most likely to participate'' method on the basis that the cost and dispatch assumptions used in the underlying analyses are subjective and difficult to verify. The Carolina Agencies state that the identified ''likely to participate'' units often wind up being those units on the system with the highest fixed costs, regardless of whether the units are of a type that one might expect to be cycled or ramped for short-term sales. If mitigated utilities are allowed to continue using this method, the Carolina Agencies urge the Commission to develop a set of generic guidelines that will yield more rigorous, less subjective analyses.[678]

ii. Standard Default Rate Methodology To Allow a Seller To Avoid a Hearing

638. With regard to whether a standard methodology should be prescribed that would allow a seller to avoid a hearing on rate methodology (*e.g.*, a methodology that is based on average costs (both variable and embedded)), many commenters urge the Commission to continue to allow flexibility rather than imposing a standard methodology based on average costs.[679]

639. Westar argues that the use of a standard methodology based on average costs would constitute a radical departure from long-settled Commission policy. Westar states that in Opinion No. 203, the Commission found that cost-based pricing cannot keep pace with fluctuating markets,[680] and that imposing average cost pricing would only exacerbate the market inefficiencies that result under cost-based rate making by eliminating pricing flexibility and lowering ceiling rates.[681]

640. Westar adds that public utilities have the statutory right under section 205 to propose and file their rates, and that the Commission lacks the power to impose rates upon public utilities.[682] Westar therefore opposes standardizing cost-based rates in any manner that would curb a mitigated seller's section 205 discretion to select a pricing methodology.[683] Westar contends that the Commission's section 206 authority to require rate changes is limited to instances where the Commission finds that the utility's presumptively just and reasonable existing rate is unjust and unreasonable, and that the Commission's proposed alternative is just and reasonable.[684] According to Westar, the NOPR offers no support for a finding that the wide variety of previously approved cost-based rate methodologies are no longer just and reasonable, and must be replaced with a standardized rate method.[685]

641. Duke and PPL support ''up to'' rates [686] based on the embedded costs of

[672] EEI at 30–31.

[673] MidAmerican at 12; Duke reply comments at 14; EEI reply comments at 20.

[674] Pinnacle at 11.

[675] *See, e.g.*, NC Towns at 4–5; NRECA at 30–32 (utilities with a portfolio of generation units of various vintages and operating characteristics could manipulate the rate ceiling and undermine mitigation).

[676] APPA/TAPS at 44–45; Carolina Agencies at 24–25; AARP at 8.

[677] APPA/TAPS at 46; AARP at 8. Alternatively, both APPA/TAPS and the Carolina Agencies agree that the Commission's proposal to use an average embedded cost basis for mid-term sales would be acceptable and would avoid the need to make determinations about units most likely to run. APPA/TAPS at 4, 44–47; Carolina Agencies at 24.

[678] Carolina Agencies at 24.

[679] *See, e.g.*, Westar at 14; MidAmerican at 11; PPL reply comments at 17–18; Southern at 66–67; Duke at 10; Progress Energy at 10–12; Xcel at 10; EEI at 30–31.

[680] Similarly, Southern states that the use of an ''up to'' rate design protects customers against unreasonably high prices (the purpose of mitigation in the first place), while giving mitigated sellers the ability to respond to pricing and market dynamics. Southern at 66; *see also* EEI reply comments at 19–20; Xcel at 10.

[681] Westar at 14, 23.

[682] *Id.* at 17–18, 23–24 (*citing Atlantic City Electric Company* v. *FERC,* 295 F.3d 1, 9 (D.C. Cir. 2002)).

[683] *See* Westar at 14, n.26 (claiming that an average cost methodology would eliminate the seller's discretion in designating particular units as ''likely to participate'' in cost-based sales and conflicts with utilities' fundamental rights under section 205 of the FPA, and long-standing precedent under the ''units most likely'' methodology.)

[684] *Id.* at 18 (citing *Tennessee Gas Pipeline Company* v. *FERC,* 860 F.2d 446, 456 (D.C. Cir. 1988)); *see also id.* at 23–24. *See also* MidAmerican reply comments at 22.

[685] Westar at 24.

[686] Drs. Broehm and Fox-Penner also support the use of an ''up to'' rate because it offers flexibility in conducting transactions. However, they suggest a methodology that reflects the incremental cost of new entry to encourage new investment and allow sellers a reasonable opportunity to earn a fair return on their investment. According to Drs. Broehm and Fox-Penner, the weakness of setting a price cap based on embedded cost stems from disputes that

Continued

the units most likely to provide the service.[687] According to Duke, the average costs of all units in a utility's installed generating capacity base could be quite different than the costs of the specific units most likely to participate in the short-term wholesale market.[688] As such, Duke claims that a system-average cost approach could force the mitigated seller to charge non-native load customers less than the cost actually incurred for generating power whenever incremental costs are greater than average costs, thereby creating a disincentive for the mitigated seller to market wholesale power in a control area where it does not have market-based rate authority.[689]

642. Progress Energy states that it opposes a standardized methodology because it will not send appropriate price signals to customers or appropriately compensate the seller for costs where the seller's generating units or the customer's usage deviates materially from the standardized methodology. Rather than adopting a ''units most likely'' approach, Progress Energy prefers a methodology that identifies units based on load conditions that are more closely associated with typical market clearing opportunities, between the average of monthly minimum loads and the average of monthly peak loads. Such an approach, Progress Energy argues, better represents conditions where sales occur.[690]

643. While supporting flexibility in the design of up-to rates,[691] Ameren urges the Commission to prescribe a standard methodology that sellers could opt to use to avoid prolonged and costly factual disputes. Ameren asserts that a formula rate based on information from FERC Form No. 1, where available, and incorporating the AEP Methodology[692] could easily form the basis of such a standard methodology.[693]

644. Because of concerns with regard to the discretion given to sellers to choose units used to calculate the cost-based rate, the NC Towns assert that a standard, system-average ratemaking methodology would provide a certainty beneficial to both utilities and wholesale customers, as well as help reduce protracted negotiations and litigation surrounding parties' concepts of a cost-based rate.[694]

645. For mid-term sales that carry a capacity charge, the Carolina Agencies contend that charge should be based on the utility's fully allocated system-wide cost of capacity. The Carolina Agencies state that energy associated with the purchased capacity also should be priced on a system average basis, in order to adhere to the principle that capacity and energy charges be developed on a consistent basis.[695] For these mid-term sales, the Carolina Agencies also support giving Load Serving Entities (LSEs) located within the mitigated utility's control area an option between: (1) Locking-in their price for capacity and/or energy in advance of delivery, at the mitigated utility's forecasted cost of energy and its cost-based tariff rate for capacity; or (2) having their charges determined through a formula rate that would charge purchasers an annually-updated price reflecting the utility's actual system-wide average costs.[696]

646. The Carolina Agencies add that any change in the Commission's pricing policy that would yield more reasonable cost-based rates must be coupled with a ''must-offer'' requirement. Lower cost-based rates without a concurrent ''must-offer'' requirement, they argue, will only provide the mitigated utility with an even greater incentive to sell all its available power beyond the mitigated region, thereby exacerbating the problems of depleted supply and profiteering by remaining suppliers.[697]

647. For mid-term sales, NRECA asks the Commission to enforce a matching or consistency principle. Here, NRECA advocates using the same generating units ''as the basis for the fixed and variable costs in determining the default embedded-cost rate. In no case should a seller be allowed to mix high-fixed-cost units with high-variable-cost units to artificially inflate the embedded-cost rate. If a seller can show that a portfolio of generating units is likely to be used to provide service, then the seller might be permitted to use a weighted average of the fixed and variable costs of the portfolio.''[698]

Commission Determination

648. Under the Commission's current policy, the default mitigation rate for mid-term sales (sales of more than one week but less than one year) is priced at an embedded cost ''up to'' rate reflecting the costs of the unit(s) expected to provide the service. The Commission will retain this approach as the default mitigation for mid-term sales. As is the case with sales for one week or less, sellers may choose to adopt the default cost-based rate or propose alternative cost-based rates.

Selecting the Particular Units That Form the Basis of the ''Up to'' Rate

649. When a seller adopts the default cost-based mid-term rate or otherwise proposes a cost-based rate designed on the unit or units expected to run, the Commission will continue to allow the seller flexibility in selecting the particular units that form the basis of the ''up to'' rate. Entities that included various proposals for ''up to'' cost-based rate methodologies in their comments may propose those or other methodologies as alternatives to the default cost-based rates, and the Commission will consider any such proposal on a case-by-case basis. Any seller proposing an alternative mitigation methodology, including a cost-based methodology with demand or capacity charges, carries the burden of justifying its proposal.

650. We agree with commenters that the Commission has the ability to verify the validity of the seller's analysis and will continue to do so in our review of proposed cost-based rates. We will continue to conduct our own analysis of whether a proposed cost-based rate is just and reasonable and, if warranted, will set such a proposed rate for evidentiary hearing where there are issues of material fact.

651. In response to the concerns raised by some commenters regarding the discretion given to sellers in the design of ''up-to'' rates, as noted above, the Commission considers all evidence when reviewing a cost-based rate proposal and, if a company has not justified selection of certain generating

---

arise over which units are selected as the basis for the price cap. Because the cost of new entry methodology would allow the price cap to be formulaic and generic based on the estimate of the annualized total cost of building a new combustion turbine peaking facility, they suggest that this approach would minimize discretion in determining the foundation of a cost-based rate. Drs. Broehm and Fox-Penner at 16.

[687] Duke at 10; Duke reply comments at 13–14; PPL reply comments at 17–18.

[688] Duke at 10; *see also* MidAmerican at 9–11; PPL reply comments at 17–18; Southern at 66–67.

[689] Duke at 10; Duke reply comments at 14.

[690] Progress Energy at 11–12.

[691] Ameren maintains that allowing mitigated sellers to sell at cost-based ''up to'' rates from which the seller may discount adequately mitigates the seller's market power while still allowing that entity to participate in competitive markets. Ameren states that ''up to'' rates thus can benefit customers by resulting in a more robust market. Ameren at 15.

[692] *American Electric Power Company,* 88 FERC ¶ 61,141 at 61,453–54 (1999). Under this methodology, Ameren explains that a seller must develop a cost-based annual rate, which then is divided by 52 to derive a weekly rate, which then is divided by 5 to derive a daily peak rate, which then is divided by 16 to derive an hourly peak rate. Ameren at 15.

[693] Ameren at 16.

[694] NC Towns at 4–5.

[695] Carolina Agencies at 11; *see also* APPA/TAPS at 46–47, n.50 (*citing Florida Power & Light Co.,* 66 FERC ¶ 61,227 at 61,532 (1994)).

[696] Carolina Agencies at 11.

[697] Carolina Agencies at 25.

[698] NRECA at 32.

units, we will not accept the proposed rate. Under the FPA, we have the authority to accept, reject, or modify a proposed rate based on an analysis of the specific facts and circumstances.

652. Further, we find that the approach we adopt in this regard allowing sellers flexibility in designing ''up to'' rates for purposes of mitigation, subject to Commission review and approval, is consistent with the Commission's historical approach to the pricing of cost-based rates. Because the Commission will have the opportunity to review a seller's proposed ''up to'' rates, we find that allowing mitigated sellers flexibility in choosing which units are used to calculate the proposed cost-based rate will not result in market-based rates being disguised as cost-based mitigated rates.

653. In response to Pinnacle's suggestion that the Commission make available a stacking methodology to be used to determine which units are most likely to run, we will do so for informational purposes and will make the methodology available on the FERC Internet site. We also note, however, that sellers may propose to use their own stacking methodology.

654. With regard to the Carolina Agencies' question of whether pricing service based on the costs of units ''likely to participate'' is sufficiently rigorous to meet the operative statutory standards, we find that it is. Historically, the Commission has allowed such an approach and the Carolina Agencies have failed to convince us that, whether or not the underlying analysis is difficult to verify, the approach does not result in just and reasonable rates. In addition, with regard to Carolina Agencies' position with regard to a ''must-offer'' provision, we discuss proposals for a ''must-offer'' provision below in the section on protecting mitigated markets.

Standard Default Rate Methodology To Allow a Seller To Avoid a Hearing

655. Regarding a standard default rate methodology that would allow a seller to avoid a hearing on rate methodology (*e.g.*, a methodology that is based on average costs (both variable and embedded)), we note that the Commission has approved various rate methodologies in the past. Rather than adopting a specific default rate methodology in this Final Rule, we affirm that, to the extent the Commission has previously accepted a particular rate methodology, that methodology is presumed to be just and reasonable until the Commission makes a contrary finding.[699]

656. The Commission will continue to allow sellers flexibility in designing ''up to'' cost-based rate proposals as alternatives to the default methodology. Entities that included various proposals for ''up to'' cost-based rate methodologies in their comments may propose those or other methodologies as alternatives to the default cost-based rates, and the Commission will consider any such proposal on a case-by-case basis.[700] Any seller proposing an alternative mitigation methodology carries the burden of justifying its proposal.

657. We acknowledge that a standard default rate methodology may provide, as several commenters suggest, some level of certainty and avoid prolonged factual disputes. However, we are persuaded by the concerns expressed by others that designing a standard default rate methodology based, for example, on average costs may not account for the actual costs of the units making the sales, and thus may not allow the seller to recover its costs.

c. Sales of One Year or Greater

Comments

658. While the NOPR did not propose changes to the default pricing for long-term sales (sales of one year or more), several entities filed comments on that issue. APPA/TAPS and AARP reiterate their support for pricing such sales on an embedded cost basis.[701] They submit that the Commission should not depart from its default cost-based mitigation policy with regard to long-term sales. The NC Towns also favor using system average costs in a rate base, rate of return model for determining long term cost-based rates.[702] Similarly, the Carolina Agencies assert that long-term sales to embedded LSEs should be priced at the mitigated utility's fully allocated average embedded cost of capacity and system average energy costs. As with short-term sales, the Carolina Agencies urge the Commission to allow the embedded LSEs the choice between: (1) Locking-in their price at the mitigated utility's embedded cost rates; or (2) agreeing to have their charges determined through an annually updated formula rate that reflects the utility's actual system-wide average costs.[703]

Commission Determination

659. We will retain our existing policy for sales of one year or more (long-term) sales. Specifically, we will continue to require mitigated sellers to price long-term sales on an embedded cost of service basis and to file each such contract with the Commission for review and approval prior to the commencement of service.[704] We discuss below the Carolina Agencies' request for a ''must offer'' requirement.

d. Alternative Methods of Mitigation

Commission Proposal

660. In the NOPR, the Commission noted that sellers that are found to have market power (*i.e.*, after the Commission has ruled on a DPT analysis), or that accept a presumption of market power, can either accept the Commission's default cost-based mitigation measures or propose alternative methods of mitigation. With regard to alternative methods of mitigation, the Commission asked in the NOPR whether it should allow as a means of mitigating market power the use of agreements that are not tied to the cost of any particular seller but rather to a group of sellers. The Commission asked whether the use of such agreements as a mitigation measure would satisfy the just and reasonable standard of the FPA.

Comments

661. Many commenters favor allowing alternative mitigation methods tied to the costs of a group of sellers, in particular the Western Systems Power Pool Agreement (WSPP Agreement),[705] or transparent competitive market prices in regional markets. Xcel asserts that the FPA does not require a mitigated rate to reflect a utility's own cost-of-service.[706]

662. E.ON U.S. supports mitigation that sets prices at competitive market

[699] In response to Westar, as discussed herein, Commission precedent supports flexibility in designing cost-based rates and we are not proposing to standardize cost-based rates here. Upon loss or surrender of market-based rate authority a seller has a number of options on how to make wholesale power sales. It can revert to a cost-based rate tariff on file with the Commission, file a new proposed cost-based rate tariff, or propose other mitigation. While we provide a default cost-based rate methodology, we also allow a seller to submit its own cost-based mitigation. On this basis, a seller's filing rights under section 205 of the FPA are not eroded and we are not finding methodologies different from the default methodology necessarily to be unjust and unreasonable.

[700] In response to Pinnacle's request for clarification that the variable cost for the unit can be defined as the system incremental cost, a mitigated seller can make that argument in support of an alternative cost-based mitigation methodology.

[701] APPA/TAPS at 47; AARP at 8.

[702] NC Towns at 4.

[703] Carolina Agencies at 12–13.

[704] April 14 Order, 107 FERC ¶ 61,018 at P 151, 155.

[705] Westar at 26–27; Pinnacle at 10; Ameren at 16–17; PG&E at 22; MidAmerican at 12; Xcel at 8; PPL reply comments at 18; and PNM/Tucson reply comments at 2–3.

[706] Xcel reply comments at 7.

levels. It claims that cost-based rate mitigation eliminates the potential for new competition in a mitigated area. In this regard, E.ON U.S. argues that profits are available only when market prices are below the mitigated utility's cost-based rates, which reduces the incentive for investment in new generation as long as buyers can obtain below market-price energy from generation facilities of the mitigated utility's ratepayers.[707] E.ON U.S. adds that mitigation reflective of competitive prices results in mitigated sellers that are indifferent as to the buyer's location and competitive price signals to which buyers can respond accordingly.[708]

Use of the WSPP Agreement Rate To Mitigate Market Power

663. Several entities suggest that the rates under the WSPP Agreement may be an appropriate alternative mitigation method.[709] Westar asserts that the purpose of the cost-based rate schedules under the WSPP Agreement is to mitigate perceived market power,[710] and notes that the Commission has also accepted use of the WSPP Agreement to mitigate market power in various contexts.[711] Westar contends that parties to the WSPP Agreement may sell under the cost-based rate schedules of the WSPP Agreement regardless of whether they have a separate tariff and authorization from the Commission.[712] Thus, Westar claims that the NOPR's implicit question whether additional authorization is needed to make mitigated sales is misplaced since the WSPP Agreement, as an accepted tariff/rate schedule, establishes the lawful filed rate.

664. Pinnacle notes that the WSPP Agreement's price caps were established based on a system-wide average cost and serve to put entities without market-based rate authority on a similar footing. In Pinnacle's view, such agreements enhance liquidity in the regional markets and facilitate transactions due to the commonality of terms and conditions.[713]

665. PG&E adds that the WSPP Agreement is the most commonly used standardized power sales contract in the electric industry. PG&E states that the WSPP membership continuously updates the WSPP Agreement to ensure that it represents up-to-date terms for power sales contracts and notes that the process of updating its terms involves a diversified, experienced group of market participants focused on developing an appropriate rate for short-term sales. PG&E concludes that the terms of the WSPP tariff should be an accepted alternative rate to the default rate determined by the Commission.[714]

666. In contrast, APPA/TAPS and AARP oppose alternative mitigation methods tied to the costs of a group of sellers because there is no assurance that the group rate would reflect the costs of the seller subject to mitigation.[715] Further, APPA/TAPS have concerns that selecting the appropriate group and obtaining the necessary cost information could be extremely difficult and controversial.[716]

Commission Determination

667. We will address on a case-by-case basis whether the use of an agreement that is not tied to the cost of any particular seller but rather to a group of sellers is an appropriate mitigation measure.

668. With regard to the WSPP Agreement, as discussed below, we conclude that use of the WSPP Agreement may be unjust, unreasonable or unduly discriminatory or preferential for certain sellers. Therefore, in an order being issued concurrently with this Final Rule, the Commission is instituting a proceeding under section 206 of the FPA to investigate whether, for sellers found to have market power or presumed to have market power in a particular market, the WSPP Agreement rate for coordination energy sales is just and reasonable in such market.

669. The WSPP Agreement was initially accepted by the Commission on a non-experimental basis in 1991,[717] providing for flexible pricing for coordination sales and transmission services. Currently, there are over 300 members of the WSPP Agreement located from coast to coast in the United States and Canada, including private, public and governmental entities, financial institutions and aggregators, and wholesale and retail customers. The WSPP Agreement as it exists today permits sellers of electric energy to charge either an uncapped market-based rate (for public utility sellers, they must have obtained separate market-based rate authorization from the Commission to do this), or an ''up to'' cost-based ceiling rate. For sellers without market-based rate authority, the cost-based ceiling rate under the WSPP Agreement consists of an individual seller's forecasted incremental cost plus an ''up-to'' demand charge based on the costs of a sub-set (eighteen sellers) of the original WSPP Agreement members, not necessarily the costs of any one seller. The up-to demand charge is based on the average fixed costs of the generating facilities of that sub-set of WSPP Agreement members; it was designed to reflect the costs of a hypothetical average utility member in 1989. The only limitations are: (1) That the trades by Commission-regulated public utilities must be short-term (lasting one year or less), and (2) that they be priced at or below the ceilings for sellers without market-based rate authority.

670. In a number of recent orders, the Commission accepted the use of the WSPP Agreement as a mitigation measure subject to the outcome of the instant proceeding and any determinations that the Commission makes regarding mitigation in this proceeding. In those cases, we explained that the WSPP Agreement contains a Commission-approved cost-based rate schedule that has been found to be just and reasonable. Further, we noted that parties to the WSPP Agreement have ''the option of transacting under the WSPP Agreement and thus can make sales under the WSPP Agreement without any further authorization from the Commission.'' [718]

---

[707] E.ON U.S. reply comments at 3; *see also* EPSA at 13.

[708] E.ON U.S. reply comments at 3.

[709] *See, e.g.*, Westar at 26 (''The Commission developed and approved the rates under Schedules A and C of the WSPP Agreement as 'rates that are within the zone of reasonableness and that are just and reasonable under the [Federal Power Act]''' (citing *Western Systems Power Pool,* 55 FERC ¶ 61,099, at 61,321 *(WSPP), order on reh'g, Western Systems Power Pool,* 55 FERC ¶ 61,495 (1990), *aff'd in relevant part and remanded in part sub nom. Environmental Action and Consumer Federation of America* v. *FERC,* 996 F.2d 401 (D.C. Cir. 1992), *order on remand,* 66 FERC ¶ 61,201 (1994)); Pinnacle at 10; PG&E at 22.

[710] Westar at 26 (*citing Pacific Gas and Electric Company*, 38 FERC ¶ 61,242 (1987) (accepting WSPP Agreement on experimental basis); *Pacific Gas and Electric Company,* 50 FERC ¶ 61,339 (1990) (reducing the ceiling price on economy energy and capacity service under Schedules A, B and C from $245/MWh to $124/MWh); *WSPP; Western Systems Power Pool*, 83 FERC ¶ 61,099 (1998) (order accepting amendments); *Western Systems Power Pool,* 85 FERC ¶ 61,363 (1998) (Letter Order accepting revised WSPP Agreement); *Western Systems Power Pool, Inc.*, 95 FERC ¶ 61,483 (2001) (order accepting amendments)).

[711] *Id.* (citing, among other cases, *Western Resources, Inc.,* 94 FERC ¶ 61,050, at 61,247 (2001) (accepting WSPP Agreement to mitigate potential affiliate preference concerns between prospective merger partners)).

[712] *Id.* at 27 (citing *NorthPoint Energy Solutions, Inc.,* 107 FERC ¶ 61,181 (2004) (rejecting wholesale cost-based rate tariff as unnecessary in light of seller's intent to make sales under the WSPP Agreement)).

[713] Pinnacle at 10.

[714] PG&E at 22.

[715] APPA/TAPS at 47; AARP at 8.

[716] APPA/TAPS at 41.

[717] *WSPP*, 55 FERC ¶ 61,099 (1991). Prior to 1991, the WSPP Agreement was used for three years on an experimental basis. *See Western Sys. Power Pool,* 50 FERC ¶ 61,339 (1990) (extending the initial two-year period for an additional year).

[718] *Westar Energy, Inc.,* 116 FERC ¶ 61,219 at P 33 (2006); *The Empire Dist. Elec. Co.,* 116 FERC ¶ 61,150 at P 12 (2006); *Xcel Energy Services, Inc.*,

671. Though the Commission has allowed sellers to charge flexible cost-based ceiling rates that are not necessarily based on a particular seller's own costs (such as the WSPP Agreement ceiling rate), we are concerned that the evolution and use of the WSPP Agreement ceiling rate and the evolution of competitive markets have resulted in circumstances in which the WSPP rate may no longer be just and reasonable for sellers that are found to have market power or are presumed to have market power in a particular market, *i.e.*, sellers under the WSPP Agreement that do not have market-based rate authority or that lose or relinquish market-based rate authority.

672. We recognize that the ceiling rate under the WSPP Agreement has been found to be a just and reasonable cost-based rate by this Commission as well as by the U.S. Court of Appeals for the D.C. Circuit,[719] and that it has been in use for over 15 years by sellers irrespective of whether they have market power. Nevertheless, the WSPP Agreement ceiling rate contains extensive pricing flexibility and relies in part on market forces to set the rate at or below the demand charge cap, and we believe the WSPP Agreement rate needs to be revisited in light of its widespread use and changes in electric markets since 1991. When originally approved by the Commission in 1991, there were 40 members under the WSPP Agreement; now there are over 300 members. Additionally, the WSPP Agreement is now used by entities not only in the Western Interconnection, but throughout the continental United States. Further, the demand charge component of the WSPP Agreement ceiling rate is based on the costs of only 18 of the original WSPP members in 1991 (utilizing 1989 data) and does not reflect the costs of the members that joined the agreement since 1991.

673. For these reasons, concurrently with issuance of this Final Rule, we are instituting in Docket No. EL07–69–000 a proceeding under section 206 of the FPA to investigate whether the WSPP Agreement ceiling rate is just and reasonable for a public utility seller in a market in which such seller has been found to have market power or is presumed to have market power. All interested entities will have an opportunity to address this issue through a paper hearing.

674. As noted above, the Commission has accepted, subject to the outcome of this rulemaking proceeding, the use of the WSPP Agreement ceiling rate as mitigation by a number of sellers. These sellers may continue to use the WSPP Agreement ceiling rate as mitigation, subject to refund (and the refund effective date established in Docket No. EL07–69–000) and subject to the outcome of the section 206 proceeding.

Market-Based Proposals for Mitigation

Comments

675. Commenters are generally concerned that where the Commission's current mitigation approach focuses on a seller's own cost of service, it imposes cost-based rates on a mitigated utility in the home control area regardless of whether the prices of alternative sources of supply in the mitigated market exceed the mitigated seller's cost-based rates.[720] Rather than relying on cost-based price caps that may bear no relationship to market conditions, several commenters support allowing mitigation methods based on transparent competitive market prices in regional markets.[721] Commenters suggest various market indicia that the Commission could use as price proxies in market-based mitigation alternatives.[722]

676. Because different markets may be uncompetitive for different reasons, and the same mitigation measure is not necessarily equivalent in all situations, several commenters urge the Commission to consider more tailored, market-based rate approaches to mitigation on a case-by-case basis.[723] MidAmerican suggests that any specific index chosen could be reflected in the tariff of mitigated sellers (for sales up to one year) or in agreements filed with the Commission (for sales of one year or longer).[724]

677. Duke explains that market-based rate mitigation alternatives could be applied to mitigated sellers whose control area markets are adjacent to a Commission-approved market. If the proxy prices are established in markets that the Commission has found to be functionally competitive, Duke contends that the price will by definition be just and reasonable. Duke submits that the Commission approved similar mitigation for sales by the LG&E Parties sinking in the Big Rivers control area capped at the Midwest ISO's LMP at the Big Rivers control area interface.[725]

678. E.ON U.S. argues that allowing index-based price caps as a mitigation option is just and reasonable because such sales are either subject to the market monitoring provisions of an RTO, or in the case of price indices, are structured according to the Commission's instructions with regard to market price reporting. They add that index-based price caps are efficient because: (a) They can be used to address pricing requirements for varying time commitments; (b) they meet the Commission's criteria for accurate and timely reporting; and (c) they do not require the administrative overhead and complexity associated with calculating and reporting cost-based rates.[726]

679. MidAmerican and the Oregon Commission submit that using an appropriate price index as a proxy could ensure that prices are derived from competitive conditions and do not reflect the market power of the mitigated seller (or, for that matter, of *any* seller).[727] Duke, MidAmerican, and the Oregon Commission reason that allowing a published price index would effectively make the mitigated seller a price taker rather than a price setter.[728] E.ON U.S., PNM/Tucson, and Indianapolis P&L also suggest that requiring cost-based mitigation may result in sellers giving up their market-based rate authority in mitigated areas

117 FERC ¶ 61,180 at P 49 (2006). However, we note that a review of EQR data indicates that of 65 sellers reporting contracts under the WSPP Agreement, 56 sellers reported sales under that agreement in 2006. Fifty-five of these sellers reported sales that were identified as market-based rate sales.

[719] *Environmental Action and Consumer Federation of America* v. *FERC,* 996 F.2d 401 (D.C. Cir. 1993).

[720] *See, e.g.*, Xcel at 7–9.

[721] Duke at 3, 13–14; Drs. Broehm and Fox-Penner at 16–17; MidAmerican at 12–13; E.ON U.S. at 10–12; Southern at 65, n. 104, 66; Ameren at 14; Xcel at 8–9; PNM/Tucson at 12,14; EEI at 26–29; Dr. Pace at 23; PPL reply comments at 17–18; and Oregon Commission reply comments at 2–3.

[722] For example, Duke (prices from an adjoining LMP market that are transparent and contemporaneously available); MidAmerican (reference prices for the region or from neighboring LMP markets, published index prices reported by public subscription services, or prices capped at levels reported in the Commission's Electric Quarterly Report for sales in neighboring markets); Xcel (proximate price indexes where available, the WSPP Agreement, a utility's own sales in areas where it does not possess market power, competitive solicitations with a sufficient amount of bidders or opportunity cost pricing); EEI (published index prices at liquid regional trading hubs or LMP nodal prices for adjacent Day 2 RTOs); the Oregon Commission (price at a frequently traded energy hub or an LMP determined by an adjoining RTO would be appropriate price indexes). If an appropriate and valid price index is not available, the Oregon Commission would require the seller to make mitigated sales at cost-based rates.

[723] MidAmerican at 14; NYISO at 8; Duke at 13–14; Drs. Broehm and Fox-Penner at 15.

[724] MidAmerican reply comments at 5.

[725] Duke at 14 (citing *LG&E Energy Marketing Inc.,* 113 FERC ¶ 61,229 at P 30 (2005)).

[726] E.ON U.S. at 12.

[727] MidAmerican at 13; Oregon Commission reply comments at 2; *see also* PPL reply comments at 17–18.

[728] Duke at 14; MidAmerican at 13–14; Oregon Commission reply comments at 2.

due to the significant time and expense of developing a cost-of-service filing.[729] Where sellers opt to give up market-based rate authority, these commenters conclude that buyers will be harmed by a reduction in the number of competitive options available to them in mitigated markets.

680. MidAmerican claims that using price indices would (a) Eliminate the incentive for round-trip transactions; (b) alleviate the need to determine whether the need for mitigation should be based on the point of delivery, the sink location, or some other determinant; and (c) reduce contention over how to calculate cost-based rates.[730] EEI and the Oregon Commission conclude that allowing mitigated rates to be based on competitive market prices would: (1) Maintain supply choices for captive customers by encouraging mitigated suppliers to participate actively in the mitigated markets; (2) avoid the unintended consequences of cost-based rate mitigation (*e.g.*, incentive to sell outside the mitigated region); (3) help to ensure that buyers continue to receive accurate price signals and not inappropriately lean on cost-based rates in times of peak demand; and (4) be consistent with the Commission's goal of encouraging competitive market solutions.[731]

681. APPA/TAPS reject this reasoning, arguing that a dominant supplier has other incentives not to sell to captive customers beyond just the availability of a higher price elsewhere, including the desire to disadvantage competing suppliers within its control area. Therefore, even if a market price index is used as a mitigation alternative, APPA/TAPS submit that a ''must offer'' obligation remains necessary.[732]

682. According to some commenters, capping mitigated prices at the levels of relevant price indices would also reduce the market distortions that exist under dual price systems.[733] E.ON U.S., Xcel, PNM/Tucson, Duke, EEI, MidAmerican and the Oregon Commission generally contend that allowing market-based rate mitigation methods would reduce the incentive, arising from price disparities in dual-price systems (a regime where a seller has market-based rate authority in some markets but is limited to cost-based sales in other market(s)), for mitigated sellers to seek market-based rate sales beyond the mitigated market.[734] This, in turn, would obviate the need for a ''must offer'' requirement or mitigation of sales outside the mitigated region. Somewhat similarly, EEI warns that if the Commission implements a ''must offer'' obligation, suppliers may not apply for market-based rate authorization in markets where they are likely to fail any of the market power screens.[735]

683. Some commenters add that the Commission surrenders nothing in terms of consumer protection by allowing market-based price caps as a mitigation option. In their view, permitting such mitigation will likely increase the willingness of sellers to engage in market transactions in mitigated areas and result in buyers paying no more than what is already recognized as a just and reasonable competitive market price.[736]

684. MidAmerican, E.ON U.S., PNM/Tucson, and Indianapolis P&L all note that the Commission (1) Has found that inter-affiliate sales are permissible at RTO price indices, and (2) proposes in the NOPR (at P 113–14) to extend this policy to market indices satisfying the November 19 Price Index Order.[737] These commenters argue that if sales at a meaningful market index are *per se* just and reasonable for affiliate transactions, there is no reason why such sales are not *per se* just and reasonable for non-affiliate transactions.[738] PNM/Tucson add that even in regions without organized RTO/ISO markets, sellers with market-based rate authority have established highly liquid trading hubs (*e.g.*, Four Corners or Palo Verde) that also produce market prices that are readily available, transparent, can serve as an appropriate proxy, and satisfy the Commission's index pricing standards.[739]

685. Another commenter supports the adoption of more market-oriented approaches to mitigation. For daily and hourly transactions, this commenter asks the Commission to be receptive to rates tied to an acceptable price index at a liquid trading point. For long term transactions, rather than focusing on average embedded costs, which this commenter claims are likely to be a poor proxy for market rates, the Commission should consider capacity and associated energy rates that provide a competitive rate of return on new generation units built in the region. Where transmission constraints bind only occasionally and the seller does not have market power absent such constraints, this commenter reasons that it is rational to only apply mitigated rates to sales made at the time such constraints are binding. Similarly, where indicative screens or the DPT analysis point to the existence of a market power problem in a well-defined seasonal or peak period, this commenter favors confining rate mitigation to sales made in the relevant market during that period.[740]

686. APPA/TAPS acknowledge that cost-based rates do not achieve competitive wholesale markets.[741] Ideally, wholesale customers should have a meaningful choice of suppliers whose costs are disciplined by competitive forces and remedies focused on fostering structurally competitive markets will help to ensure that future consumers have choices. Until such structural remedies are fully implemented, APPA/TAPS maintain that mitigated sellers should sell at cost-based rates.[742]

687. APPA/TAPS and Morgan Stanley do not categorically oppose the use of price indices as a mitigation alternative that could be justified with substantial evidence, but urge caution and ask the Commission not to assume that the index relied upon is a just and reasonable, and comparable, proxy for the mitigated market.[743] Morgan Stanley explains that given the price variation among transmission nodes, it is not possible to generically find that any one index-based price would be an adequate proxy for another node(s). APPA/TAPS explain that a thinly traded market, or one separated by transmission constraints, could create volatility or arbitrage possibilities that would leave captive customers worse-off than a cost-based mitigated rate. They add that appropriate price proxies may not be available for all products, and that RTO-administered real-time or day-ahead markets would not generally provide acceptable proxies for price mitigation in markets for weekly, monthly or annual sales. APPA/TAPS also note that the Southeast has no real liquid trading hubs.[744] While urging the Commission to continue requiring cost-based mitigation, Morgan Stanley does not oppose allowing mitigated sellers to

[729] Indianapolis P&L at 11; E.ON U.S. at 11; PNM/Tucson at 13.

[730] MidAmerican reply comments at 3–4, 20.

[731] EEI reply comments at 12; Oregon Commission reply comments at 3.

[732] APPA/TAPS reply comments at 15.

[733] PNM/Tuscon at 13–14; MidAmerican at 14; EEI at 26; *see also,* CAISO at 6.

[734] E.ON U.S. at 10–11; Xcel at 8–9; PNM/Tucson at 13; Duke at 9; EEI at 28; MidAmerican at 14; Oregon Commission reply comments at 3.

[735] EEI reply comments at 18.

[736] Duke at 14; APPA/TAPS at 64; MidAmerican at 13.

[737] MidAmerican at 13; E.ON U.S. at 11; PNM/Tucson at 12; Indianapolis P&L at 7.

[738] E.ON U.S. at 11; Indianapolis P&L at 11; MidAmerican reply comments at 5.

[739] PNM/Tucson at 13.

[740] Dr. Pace at 23–24.

[741] APPA/TAPS at 48.

[742] *Id.* at 48–49.

[743] APPA/TAPS reply comments at 13; Morgan Stanley reply comments at 2, 8–10.

[744] APPA/TAPS reply comments at 14–15.

justify an index-based mitigation approach as appropriate for their specific circumstances. According to Morgan Stanley, such an approach may prove justifiable where a viable, liquid index exists within or adjacent to the territory in which a finding of market power exists.[745]

688. NRECA likewise is concerned that there is no assurance that (1) The external market price would be a competitive price; (2) external markets are a reasonable proxy for non-existent competitive market prices in the mitigated market; and (3) there are sufficient monitoring and enforcement mechanisms to ensure these first two conditions are continually being met.[746] Unless these three concerns are addressed, NRECA asserts that the Commission may not lawfully rely on an external market price as a proxy in a mitigated market, particularly where the FPA is clear that the Commission may not approve market-based rates absent ''empirical proof'' that ''existing competition would ensure that the actual price is just and reasonable.''[747] Moreover, where ''Congress could not have assumed that 'just and reasonable' rates could conclusively be determined by reference to market price,'' [748] NRECA argues that the Commission may not rely exclusively on market prices but rather must have a regulatory ''escape hatch'' or ''safeguard'' mechanism [749] if actual competitive pressures alone cannot keep rates just and reasonable. NRECA, similar to APPA/TAPS, is concerned that proxy indices are irrelevant oftentimes because they are too far removed from the mitigated market to be adequately representative. While NRECA admits that such indices may be adequate in some instances, it takes the position that, at most, the Commission could entertain proxy index proposals from mitigated sellers on a case-by-case basis.[750]

689. The Carolina Agencies are similarly concerned that market-based indices based on LMPs from adjacent markets in many hours will reflect transmission congestion that may not be representative of congestion patterns in the mitigated market, and therefore must not be deemed a just and reasonable proxy for an entirely different market. Moreover, LSEs in RTOs with Day 2 markets have some ability to limit their exposure to LMP spikes through the use of hedging tools (*i.e.* Auction Revenue Rights and Financial Transmission Rights). However, the Carolina Agencies argue, LSEs in mitigated markets would face these LMP gyrations from adjacent markets as proxy prices without any hedging protections. These agencies further claim that there are no other sources of non-LMP price information in their region that are reliable enough to serve as proxy prices.[751] In the Carolina Agencies' view, because price information from non-LMP markets is mostly illiquid, non-transparent and easily manipulated due to the low volume of transactions, such reference prices are unlikely to be an accurate and reasonable proxy for competitive prices in the mitigated control area. They state that, as the Commission has reported, ''some electric power markets are almost entirely opaque both to regulators and to price takers. In these markets (such as electricity in the Southeast), so little information is available that price indices either do not develop or have little value in price discovery.'' [752] The Carolina Agencies also wonder how a meaningful proxy could be determined for a market price in a control area where a dominant supplier has market power.[753]

690. The Carolina Agencies and NASUCA oppose providing mitigated utilities with the option of filing cost-based rates or choosing the market rates of a neighboring control area.[754] NASUCA adds that commenters articulate no legal theory by which mitigated sellers should be allowed any market rate or how the Commission has power to grant any waiver of the rate filing and review requirements of section 205 of the FPA.[755] Rather than allowing mitigated rates to be determined by market prices in adjacent market areas, NASUCA urges the Commission to deny any form of market rates to mitigated utilities and require such suppliers to comply with section 205 of the FPA by filing their rates subject to the traditional review to ensure just and reasonable rates.[756]

691. If the presence of transmission constraints in a dominant transmission provider's control area allow it to charge supra-competitive market-based rates there, APPA/TAPS submit that the Commission must require these constraints to be addressed.[757] These commenters ask the Commission to impose mitigating conditions on market-based rate authority to increase access to existing transmission facilities as well as to expand their transmission access through rolled-in upgrades. For example, APPA/TAPS,[758] and the Carolina Agencies [759] suggest that the Commission could condition the market-based rate authority of a mitigated seller on the demonstrated willingness of vertically-integrated transmission owners to jointly plan and construct new generation projects with market participants, and/or to participate with them in collaborative, open regional transmission planning processes.

692. Xcel responds that, aside from such a requirement being impractical, the Commission has no legal authority to impose a condition requiring joint planning of new facilities nor jurisdiction over the construction of new facilities.[760] Xcel states that the FPA does not provide the Commission with certificate jurisdiction over generation facilities or otherwise, nor does the Commission have the authority to order utilities to enter into such a contract.[761]

Commission Determination

693. The Commission continues to believe that proposed alternative methods of mitigation should be cost-based. However, as discussed below, while we will not allow the use of alternative ''market-based'' mitigation on a generic basis, we will permit sellers to submit alternative non-cost-based mitigation proposals for Commission consideration on a case-by-case basis.

694. A variety of suggestions have been made such as basing mitigated prices on: Prices from an adjoining LMP market that are transparent and contemporaneously available; published index prices; prices capped at levels reported in the Electric Quarterly Reports for sales in neighboring markets; a utility's own sales in areas where it does not possess market power;

[745] Morgan Stanley reply comments at 9–10.

[746] NRECA reply comments at 31–33.

[747] *Id.* at 32 (*quoting Farmers Union Cent. Exch., Inc.* v. *FERC,* 734 F.2d 1486, 1510 (D.C. Cir. 1984)).

[748] *Id.* (*quoting FPC* v. *Texaco,* 417 U.S. 380, 399 (1974)).

[749] *Id.* (*quoting Louisiana Energy & Power Auth.* v. *FERC,* 141 F.3d 364, 370–71 (D.C. Cir. 1998)).

[750] *Id.* at 33.

[751] Carolina Agencies reply comments at 2–3, 10, 14–18.

[752] *Id.* at 18, n. 11 (citing Federal Energy Regulatory Commission—Office of Market Oversight and Investigations, *2004 State of the Market Report* (June 2005)).

[753] *Id.* at 15, n. 9.

[754] *Id.* at 18–19; NASUCA reply comments at 18–19.

[755] NASUCA reply comments at 18–19.

[756] *Id.*

[757] APPA/TAPS at 50.

[758] *Id.* at 40–41, 49, 50–51.

[759] Carolina Agencies at 12, n.10.

[760] Xcel reply comments on 9–10.

[761] *Id.* at 10. Duke likewise opposes any proposal granting an automatic entitlement to participate in new generation planned by the mitigated utility, arguing that the commercial terms of any joint ownership arrangements must be negotiated by the parties. Duke reply comments at 11; *see also,* EEI reply comments at 8–9.

and competitive solicitations with a sufficient amount of bidders or opportunity cost pricing. However, while some commenters suggest that market-based rate mitigation may cure several of the cost-based mitigation regime's alleged ailments, they fail to convincingly address a fundamental concern with such mitigation. That is, why a market-based price from one market would be a relevant and appropriate proxy price to mitigate market power found in a different market.

695. Specifically, we reject Duke's argument that we should allow market-based rate mitigation alternatives to be used by mitigated sellers whose control area markets are adjacent to a Commission-approved market because if the proxy prices are established in markets that the Commission has found to be functionally competitive, the price will by definition be just and reasonable. Although Duke is correct that a price in a market may be presumed to be just and reasonable in the market in which it has been approved, Duke's claim fails because that price has not been shown to be just and reasonable for other markets with differing competitive circumstances.[762] Duke's argument also fails to recognize that the Commission does not certify markets as competitive; rather, we make determinations on whether individual sellers in a market have market power. In addition, contrary to Duke's view, the Commission's acceptance of proposed mitigation in the Big Rivers control area does not support Duke's proposal in this regard. In *LG&E Energy Marketing Inc.*,[763] the Commission accepted a proposal that capped—at the Midwest ISO's LMP price at the Big Rivers control area interface—all market-based sales by LG&E sinking in the Big Rivers control area not sold pursuant to contractual agreements already in existence. However, Duke fails to point out that, when LG&E proposed to mitigate its sales into the Big Rivers control area, LG&E was a member of the Midwest ISO and, accordingly, capping LG&E's sales price at the Midwest ISO LMP at the Big Rivers interface was appropriate.

696. Commenters raise many reasons why allowing the use of an index could be beneficial such as: Using an appropriate price index as a proxy could ensure that prices are derived from competitive conditions and do not reflect the market power of the mitigated seller; allowing a published price index would effectively make the mitigated seller a price taker rather than a price setter; use of an index price would eliminate the incentive for round-trip transactions and alleviate the need to determine whether the need for mitigation should be based on the point of delivery, the sink location, or some other determinant; would maintain supply choices for captive customers by encouraging mitigated suppliers to participate actively in the mitigated markets; would help to ensure that buyers continue to receive accurate price signals and not inappropriately lean on cost-based rates in times of peak demand; and, would be consistent with the Commission's goal of encouraging competitive market solutions.

697. However, we agree with Morgan Stanley and others that, given price variations among transmission nodes, we should not generically find that one index-based price is necessarily an adequate proxy for another node. Commenters urging the Commission to consider such alternatives on a case-by-case basis acknowledge that different markets may be uncompetitive for different reasons.[764] While commenters speak of ''relevant price indexes,'' their comments contain little more than undeveloped proposals and limited discussion as to how such an index would be chosen, and why it would be an appropriate proxy for the mitigated market. For example, commenters fail to explain how a proxy price based on existing competition from one market with distinct traits such as transmission congestion ensures a just and reasonable price in another market that has its own unique traits and circumstances. Deriving prices from competitive conditions, making a mitigated seller a price taker rather than a price setter, and reducing market distortions are all goals commenters claim market-based mitigation can help achieve. Nonetheless, the use of an external market price to establish the just and reasonable price in the mitigated market has not yet been shown to be appropriate.

698. While we will not allow the use of ''market-based'' mitigation on a generic basis, we nevertheless will permit sellers to submit non-cost-based mitigation proposals, such as the use of an index or an LMP proxy, for Commission consideration on a case-by-case basis based on their particular circumstances. Sellers choosing to propose such alternative mitigation will carry the burden of showing why and how the proposed index-based price is relevant, appropriate and a just and reasonable price for the mitigated market. While several commenters also seek to have the Commission make market-based rate authorization of mitigated sellers contingent upon their pledging to jointly plan and construct future generation projects with market participants, or pursue other structural conditions, they have not justified imposing such a burden. For those sellers that are affected with a market power concern, we discuss elsewhere in this Final Rule the means by which we will require adequate mitigation. Moreover, we believe that we have adequately addressed these concerns related to planning in our recent Order No. 890, where we require all jurisdictional transmission owners to engage in transmission planning with other market participants. Therefore, we find no reason to mandate a mitigated seller's participation in such arrangements.

2. Discounting

Commission Proposal

699. In the NOPR, the Commission explained that a supplier authorized to sell under an ''up to'' cost-based rate has an incentive to discount its sales price when the market price in the supplier's local area is lower than the cost-based ceiling rate. During these periods, a rational seller will discount its sales to maximize revenue. In the past, the Commission has encouraged discounting as an efficient practice that can maximize revenues to reduce the revenue requirements borne by requirements customers.

700. Here, the primary issue is whether a seller can ''selectively'' discount, *i.e.*, offer different prices to different purchasers of the same product during the same time period. The Commission invited comment on whether selective discounting should be allowed for sellers that are found to have market power or have accepted a presumption of market power and are offering power under cost-based rates. If so, the Commission sought comment on what mechanisms (reporting or otherwise), if any, are necessary to protect against undue discrimination. By contrast, were it to forbid selective discounting, the Commission asked for comment on whether it should require the utility to post discounts to ensure that they are available to all similarly-situated customers.

[762] E.ON U.S.' proposal that the use of index-based price caps subject to the market monitoring provisions of an RTO is a just and reasonable mitigation option equally fails to address whether the index-based price is relevant to the market in which the sale is made.

[763] 113 FERC ¶ 61,229 (2005).

[764] MidAmerican at 14; NYISO at 8; Duke at 13–14; Drs. Broehm and Fox-Penner at 15.

Comments

701. Some commenters favor selective discounting because it provides an opportunity to meet competition where necessary to retain and attract business. They add that the contracting flexibility afforded by selective discounting allows sellers to modify rates and tailor sales based on customer-specific factors such as load characteristics and credit ratings. They argue that such flexibility maximizes liquidity and available capacity and energy.[765]

702. MidAmerican and Indianapolis P&L both state that section 206 of the FPA already prohibits undue discrimination and provides well-established procedures for entities that have been subjected to undue discrimination.[766] Westar notes that the Commission's long-standing policy is to allow selective discounting and asserts that discounting to customers who have competitive alternatives is not unduly discriminatory.[767]

703. PG&E maintains that it is just and reasonable for a seller to offer a discount below its cost-based mitigated rate if the seller will gain other (non-market power) advantages such as repeat customers or lower transaction costs. PG&E also suggests that principles of efficiency and competition support providing selective discounts to entities with larger needs.[768]

704. Duke contends that sales arising from selective discounting spread fixed costs over more units of service, thereby reducing the ''up to'' rate.[769] Moreover, without the ability to selectively discount, Duke submits that utilities will not have the opportunity to compete for many wholesale transactions in the mitigated control area.[770]

705. Southern asserts that if selective discounting were eliminated, then the resulting loss of a low-cost source of supply would harm the customers. In Southern's view, captive customers also lose because of foregone opportunities to optimize capacity nominally dedicated to native load service.[771] EEI adds that where a mitigated seller is already precluded from making market-based rate sales within mitigated areas, selective discounting does not give rise to conditions that support the potential exercise of market power.[772]

706. Other commenters generally oppose allowing mitigated sellers to selectively discount sales. For example, TDU Systems claim that selective discounting is unnecessary because a seller subject to cost-based mitigation in its home control area would not face competition by definition. They also contend that selective discounting would allow mitigated sellers to engage in price discrimination in a non-competitive market, thereby permitting the seller to exercise market power by economically or physically withholding capacity to increase the posited market price. Thus, in the TDU Systems' view, a rule allowing selective discounting would effectively grant market-based rate authority in a non-competitive market, in contravention of the requirements of the FPA.[773]

707. While NC Towns generally encourage discounts to cost-based rates, they oppose selective discounting because they do not believe that the size of a load should be a factor when determining whether to give a buyer a discount.[774]

708. APPA/TAPS question why a dominant seller would offer discounts to captive customers with no other viable supply options. They add that there is no evidence that local, competing generation exists or that there is available transmission capacity that could support significant imports. In order to avoid discrimination, APPA/TAPS advocate requiring a mitigated supplier to offer captive customers any discounts that it offers to other purchasers.[775] Factors such as a customer's capacity factor, credit rating or fuel costs may justify adjustments to seller-specific cost-based rates, but such factors, argue APPA/TAPS, should be reflected in the seller's cost-based rates rather than through selective discounting.[776]

709. If selective discounting is permitted, TDU Systems and NRECA urge the Commission to require sellers to file reports of the discounts offered, and encourage the Commission to vigorously enforce its market manipulation and affiliate transactions rules.[777]

710. Suez/Chevron urges the Commission to require selective discounts to be contemporaneously offered to similarly-situated buyers, and separately identified in the mitigated seller's EQR.[778] To minimize the potential for market power abuse when a mitigated seller selectively discounts to an affiliate,[779] Suez/Chevron supports requiring a presumption that nonaffiliated buyers are similarly-situated, and therefore entitled to the same discount as a mitigated seller offers to its affiliate.[780]

711. PG&E, in contrast, opposes requiring the seller to make discounts available to all similarly-situated entities. According to PG&E, it would be difficult to determine which entities are in fact similarly-situated because the seller would have to consider multiple factors, such as quantity of load, timing, flexibility, credit rating, and purchases history.[781]

712. Ameren disagrees with a posting requirement, arguing that the Commission's requirements for separate filings and advance approval of affiliate power sales provide the appropriate oversight and mechanisms necessary to police discounting concerns regarding selective discounts favoring affiliates. Ameren concludes that a requirement to post discounts is unduly burdensome given that the only discounts of concern are in the affiliate sales, which are subject to separate filing requirements.[782] PG&E, in turn, notes that the affiliate restrictions also provide protection against the use of selective discounts to benefit affiliates.[783]

Commission Determination

713. We will continue our practice of allowing discounting from the default cost-based mitigated rates for short- and mid-term sales and will permit selective discounting by mitigated sellers provided that the sellers do not use such discounting to unduly discriminate or give undue preference. We believe that selective discounting that does not constitute undue discrimination can improve liquidity, available capacity and energy, and customer supply

[765] *See, e.g.*, Indianapolis P&L at 10; MidAmerican at 15–16; Duke at 10–11; EEI at 34; PG&E at 23; Progress Energy at 12.

[766] MidAmerican at 15; Indianapolis P&L at 10.

[767] Westar at 26 (citing *Town of Norwood v. FERC,* 587 F.2d 1306, 1312 & n.17 (D.C. Cir. 1978) (rate disparity may be justified by, *inter alia,* differences in the customers' level of risk aversion and bargaining power)); *see Policy for Selective Discounting by Natural Gas Pipelines,* 111 FERC ¶ 61,309, *reh'g denied,* 113 FERC ¶ 61,173 (2005) (affirming Commission's 16-year policy to allow selective discounting by interstate natural gas pipelines when necessary to meet competition).

[768] PG&E at 23.

[769] Duke at 11.

[770] *Id.*

[771] Southern at 67.

[772] EEI at 31; *see also* PG&E at 23.

[773] TDU Systems at 19–21.

[774] NC Towns at 5.

[775] APPA/TAPS reply comments at 15–16; APPA/TAPS at 44–48.

[776] APPA/TAPS reply comments at 16.

[777] TDU Systems at 24; NRECA at 32.

[778] NC Towns and Morgan Stanley state that any discount the seller wishes to offer should be required to be posted with sufficient time for other interested parties to take advantage of the offer. NC Towns at 5–6; Morgan Stanley at 7.

[779] Suez/Chevron states that sellers should be required to post any affiliate discounts on their OASIS. Suez/Chevron at 13.

[780] Suez/Chevron at 12–13.

[781] PG&E at 24.

[782] Ameren at 17–18.

[783] PG&E at 23.

options. In other words, non-discriminatory discounting can provide benefits to the market.

714. APPA/TAPS question why a dominant seller would offer discounts to captive customers with no other viable supply options, and the TDU Systems comment that selective discounting is unnecessary because a mitigated seller by definition would not face competition in its home control area. However, in times when there are viable alternatives, a seller under an ''up to'' cost-based rate has an incentive to discount its sales price when the market price in the seller's mitigated market is lower than the cost-based ceiling rate. Allowing a mitigated seller to non-discriminatorily discount the rate when there are viable alternatives in the market benefits customers by providing more supply options in such instances.

715. Discounting also can maximize revenue by optimizing capacity nominally dedicated to native load service, allowing the supplier to spread fixed costs over more units of service. Maximizing revenue in this manner can help reduce the ''up to'' rate, and therefore the revenue requirements borne by captive customers. The Commission has previously determined that requiring a mitigated entity to limit sales to its ceiling rates ''is at odds with the long-standing policy of allowing 'up to' cost-based rates.'' [784]

716. The FPA requires that all rates charged by public utilities for the sale or resale of electric energy be ''just and reasonable.'' [785] If a seller's cost-based rate has been found to be just and reasonable by the Commission, it follows that discounted rates below such a cost-based rate are also just and reasonable.[786] However, a seller may not lawfully discount to gain, or profit from, market power advantages. We emphasize that section 205 of the FPA prohibits public utilities, in any power sale subject to the Commission's jurisdiction, from granting any undue preference or advantage to any person [787] and also prohibits undue discrimination.[788]

717. With regard to comments that the Commission establish a reporting mechanism, under the Commission's existing reporting requirements entities making power sales must submit EQRs containing: A summary of the contractual terms and conditions in every effective service agreement for all jurisdictional services, including market-based and cost-based power sales and transmission services; and, transaction information for effective short-term (less than one year) and long-term (one year or greater) power sales during the most recent calendar quarter.[789] Through this reporting requirement, the Commission monitors the rates charged by mitigated sellers.

718. Several commenters also seek to have the Commission require selective discounts to be posted and contemporaneously offered to similarly-situated buyers. Some seek a presumption that nonaffiliated buyers are similarly situated whenever a mitigated seller offers an affiliate a discount. The Commission will not require mitigated sellers to contemporaneously post in a public forum all discounts provided for cost-based sales (*i.e.*, where the sale is made at a price below the maximum up-to cost-based rate approved by the Commission in that tariff or rate schedule). Proponents of a posting requirement have not justified nor demonstrated how the Commission's EQR requirement fails to provide an adequate means by which to monitor such discounts. In addition, many sales are made below the cost-based cap, and the commenters' proposals would place an undue burden on sellers that would be required to contemporaneously post rates that the Commission has already deemed to be just and reasonable. Accordingly, the Commission will not require the contemporaneous posting of discounted cost-based rates. Finally, commenters have provided no basis to conclude that nonaffiliated buyers are similarly situated whenever a mitigated seller offers an affiliate a discount, and we will not adopt the proposed presumption in this regard. Thus, sellers may selectively discount only if they do so in a manner that is not unduly discriminatory or preferential.

719. Further, we agree with MidAmerican that identifying discriminatory selective discounting requires fact-specific evaluations. Because individual proceedings are the best instrument available to the Commission for such efforts, allegations of undue discrimination arising from selective discounting are best addressed on a case-by-case basis.

### 3. Protecting Mitigated Markets

#### a. Must Offer

##### Commission Proposal

720. Under the Commission's current mitigation policy, a seller that loses market-based rate authority in its home control area is limited to charging cost-based rates in that control area; however, there is no requirement that the seller offer its available power to customers in that home control area. Instead, the seller is free to market all of its available power to purchasers outside that control area if it chooses to do so. If, for example, market prices outside the mitigated seller's control area exceed the cost-based caps within the mitigated control area, then the seller will, other things being equal, have an incentive to sell outside. As noted in the NOPR, wholesale customers have argued that default cost-based mitigation of this kind is of little value if a seller can market its excess capacity at market-based rates in other control areas. In the NOPR, the Commission sought comment on whether its current policy is appropriate, and if not, what further restrictions are needed. The Commission asked whether it should adopt a form of ''must offer'' requirement in mitigated markets to ensure that available capacity (*i.e.*, above that needed to serve firm and native load customers) is not withheld. If so, the Commission asked if such a ''must offer'' requirement should be limited to sales of a certain period to help ensure that wholesale customers use that power to serve their own needs, rather than simply remarketing that power outside the control area and profiting. [790] If it were to adopt such a ''must offer'' requirement, the Commission asked what rules there should be to define the ''available'' capacity that must be offered , in order to avoid case-by-case disputes over this issue.

##### Comments

721. Wholesale customers generally support a ''must offer'' requirement,'' stating that it is needed to ensure that power is available for purchase in the mitigated market and to protect them from incurring higher costs to serve

[784] *Duke Power,* 113 FERC ¶ 61,192 at P 17 (2005).

[785] 16 U.S.C. 824d(a).

[786] *Public Service Company of Oklahoma,* 54 FERC ¶ 61,021, at 61,032 and fn. 8 (1991) (''If PSO's rates set at full cost are reasonable in the presence of market power, it follows that PSO's rates reflecting less than a 100-percent contribution to fixed costs are also reasonable in the presence of market power.'').

[787] 16 U.S.C. 824d(b).

[788] 16 U.S.C. 824e(a).

[789] *Revised Public Utility Filing Requirements,* Order No. 2001, 67 FR 31043 (May 8, 2002), FERC Stats. & Regs. ¶ 31,127 (2002). Required data sets for contractual and transaction information are described in Attachments B and C of Order No. 2001.

[790] In this regard, the Commission asked if there should be an annual open season under which the mitigated seller offers its available capacity to local customers for the following year at the cost-based ceiling rate and, if customers do not commit to purchase that capacity, then the seller would be free to sell the remaining capacity at market-based rates where it has authority to do so.

load.[791] They argue that the existence of a dual price system (a regime where a seller has market-based rate authority in some markets but is limited to cost-based sales in other market(s)) creates an incentive for a mitigated seller to sell its power outside of the mitigated market whenever market prices in the outside market are above the mitigated seller's cost-based price. They are concerned particularly with the situation where a wholesale customer faces few or no alternatives in the mitigated market due to transmission constraints.

722. APPA/TAPS, the Carolina Agencies and NRECA claim that the Commission has both the authority and obligation to remedy undue discrimination in wholesale sales, which are clearly set forth in sections 205 and 206 of the FPA.[792] They specifically argue that a ''must offer'' condition is within the Commission's authority as a remedy for the unjust and unreasonable rates and undue discrimination (refusal to sell in the mitigated control area) that are a consequence of the mitigated seller's accumulation of market power.[793] Several commenters reason that, similar to imposing reporting requirements and other conditions on a grant of market-based rate authority, where a seller no longer has market-based rate authority in its home control area, the Commission may impose a ''must offer'' condition on the continuation of market-based rate authorization outside a mitigated seller's control area.[794] APPA/TAPS and the Carolina Agencies argue that the Commission already imposed a must-offer obligation on the continued availability of market-based rate authority for sellers in the California markets.[795]

723. APPA/TAPS also assert that while Order No. 888 rejected a generic obligation that would have required sellers to continue wholesale sales past the expiration of the contract(s) in question in that proceeding, Order No. 888 explained that the Commission can impose an obligation to continue service on a case-by-case basis.[796]

724. APPA/TAPS and the Carolina Agencies argue that a dominant public utility's physical withholding of generation in the mitigated market in order to make market-based sales elsewhere results in undue discrimination that the Commission has an obligation to remedy. They assert that because wholesale customers in the mitigated market are harmed through decreased supply, increased market concentration, and increased prices, these customers are exposed to the type of injury against which the FPA was designed to protect.[797] The Carolina Agencies also maintain that, whether or not exporting behavior can be considered economically efficient, such behavior results in undue discrimination between (i) The mitigated utility's native load and (ii) LSEs located within the mitigated utility's home control area.[798] This outcome, the Carolina Agencies continue, violates the FPA's mandate that rates be just, reasonable and not unduly discriminatory regardless of whether the mitigated utility's decision to export power is a conscious ''withholding'' for anticompetitive ends.[799] APPA/TAPS and Carolina Agencies add that vertically-integrated utilities with substantial generation in their home control areas frequently have the ability and incentive to discriminate against their wholesale customers, who compete against them on both the wholesale and retail level.[800]

725. APPA/TAPS and Carolina Agencies maintain that undue discrimination occurs if a dominant public utility unjustifiably disadvantages a class of market participants. They cite case law that the D.C. Circuit found ''upholds the power of the Commission to subject approval of a set of voluntary transactions to a condition that providers open up the class of permissible users.'' [801] Absent relevant circumstances that render two sets of customers differently situated, they assert that it is unduly discriminatory for a public utility to sell wholesale power to one set of customers (at market-based rates) while denying service to another set (to whom sales, if made, would need to be priced at cost-based rates). They contend there is no justification for disparate treatment in such a case and, therefore, the Commission is obligated under sections 205 and 206 to remedy such undue discrimination by either denying or conditioning the grant of market-based rate authority outside of the mitigated home control area. A ''must offer'' condition, they claim, would satisfy this obligation by preventing undue discrimination.[802]

726. APPA/TAPS and the Carolina Agencies further allege that, while it may not be unduly discriminatory for a utility to elect to sell to the wholesale

[791] *See, e.g.*, APPA/TAPS at 40–42 (also urging the Commission to apply any ''must offer'' requirement to captive customers in the seller's transmission service area); Carolina Agencies at 10–13; NRECA at 35; Montana Counsel at 19; TDU Systems at 19; NC Towns at 6–8 (asking the Commission to require mitigated utilities to serve wholesale customers in the mitigated control area at long-term system average cost-based rates in order to maintain reliability). *See also* MidAmerican reply comments at 9–12 (arguing that the APPA/TAPS and Carolina Agencies proposals suffer from significant policy flaws).

[792] APPA/TAPS and Carolina Agencies supplemental comments at 4, 9–18 (citing, among others, 16 U.S.C. 824d(a), 824d(b), 824e(a); *Associated Gas Distributors* v. *FERC,* 824 F.2d 981, 998 (D.C. Cir. 1987)).

[793] NRECA reply comments at 41 (citing *New York* v. *FERC,* 535 U.S. 1, 27 (2002); *Transmission Access Policy Study Group* v. *FERC,* 225 F.3d 667, 683–88 (D.C. Cir. 2000), *aff'd sub nom. New York* v. *FERC,* 535 U.S. 1 (2002)); Carolina Agencies at 4–5; Carolina Agencies reply comments at 2. *See also* Montana Counsel at 19 (citing *Atlantic Ref. Co.* v. *Public Serv. Comm'n of N.Y.,* 360 U.S. 378 (1959) and U*nited Gas Improvement Co.* v. *Callery Properties, Inc.,* 382 U.S. 223 (1965), two cases in which the Montana Counsel claim that the Supreme Court, in recognition of the market power of natural gas producers and the public interest provisions of the NGA, ''virtually ordered'' the Commission to exercise its jurisdiction to condition producer natural gas certificates and rate orders to limit gas prices); APPA/TAPS and Carolina Agencies supplemental comments at 2, 18–30; NRECA supplemental comments at 6–7.

[794] APPA/TAPS at 37–38; APPA/TAPS reply comments at 8; Montana Counsel at 21–22; Carolina Agencies at 4–5; Carolina Agencies reply comments at 3–4.

[795] APPA/TAPS and Carolina Agencies supplemental comments at 27 (citing *San Diego Gas & Elec. Co.* v. *Sellers of Energy and Ancillary Servs. Into Mkts. Operated by the Cal. Ind. Sys. Operator and the Cal. Power Exch.,* 93 FERC ¶ 61,294, at 62,010–11 (2000) (extended-refund-period condition), order *on rehearing and clarification,* 97 FERC 61,275, at 62,243–44 (2001), order *on rehearing and clarification,* 99 FERC ¶ 61,160 (2002), *on rehearing and clarification,* 105 FERC ¶ 61,065 (2003), *petitions for rev. granted in part sub nom. Bonneville Power Auth.* v. *FERC,* 422 F.3d 908 (9th Cir. 2005) and *Public Utils. Comm'n of Cal.* v. *FERC,* 462 F.3d 1027, 1043 (9th Cir. 2006) (discussing must-offer condition)).

[796] APPA/TAPS at 39 (citing Order No. 888—''we continue to believe that the extent to which a customer could demonstrate a reasonable expectation of continued service at the existing contract rate (or at a cost-based rate, if that was the customer's expectation) is best addressed on a case-by-case basis''); *see also* Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,805 & n.652 (1996) (explaining that although the Commission determined ''not to impose a regulatory obligation on wholesale requirements suppliers to continue to serve their existing requirements customers,'' ''any party claiming to be aggrieved by a utility's alleged abuse of generation market power under a wholesale requirements contract can file a complaint with the Commission under Section 206''); *see also* Montana Counsel at 22.

[797] APPA/TAPS and Carolina Agencies supplemental comments at 19.

[798] Carolina Agencies at 6.

[799] *Id.* at 9.

[800] APPA/TAPS and Carolina Agencies supplemental comments at 16 (citing *FPC* v. *Conway Corp.,* 426 U.S. 271, 278 (1976) to further argue that the Commission can and must take account of competition at retail when determining whether such discrimination exists.)

[801] *Id.* at 13 (citing *Central Iowa Power Coop.* v. *FERC,* 606 F.2d 1156, 1172 (D.C. Cir. 1979); and quoting *Associated Gas Distributors* v. *FERC,* 824 F.2d 981, 999 (D.C. Cir. 1987)). APPA/TAPS and Carolina Agencies claim that in this case, a must offer requirement would expand the class of buyers of the mitigated seller's wholesale services to include customers from the mitigated utility's home control area.

[802] *Id.* at 15–16.

customer who will pay the highest price, it is unduly discriminatory if the price differential is based upon mitigation required as a result of the seller's market power.[803] Where sellers claim a right to seek the highest prices, APPA/TAPS and the Carolina Agencies counter that this profit maximization impulse can neither justify the exercise of market power nor insulate it from correction.[804]

727. According to APPA/TAPS and the Carolina Agencies, it is also unduly discriminatory for a mitigated seller to make market-based rate sales outside its home control area when constraints on that entity's own transmission system prevent embedded customers from similarly accessing those markets as buyers. They argue that refusal to sell wholesale power supplies to embedded LSE customers at fully-compensatory cost-based rates effectively compounds the de facto denial of access by exacerbating both the discrimination and the resulting harm.[805] According to APPA/TAPS and the Carolina Agencies, the claim that mitigated sellers are merely engaging in economically efficient behavior ignores the market power that the sellers possess.[806] They state that when captive customers have few or no supply alternatives in the mitigated market and are constrained from accessing opportunities in the broader market (even with open access tariffs), and the dominant supplier sells its excess capacity beyond the mitigated market, the resulting reduction in output in the mitigated market is not addressed simply by prohibiting the mitigated seller from selling at unmitigated prices in the mitigated region.[807] They conclude that it would be unjust and unreasonable to permit or facilitate such withholding by allowing unconditioned sales at market-based rates outside a mitigated supplier's home control area; this would reserve the benefits of competitive markets exclusively to dominant public utility sellers.[808]

728. A number of commenters claim that a ''must offer'' requirement is necessary due to their lack of viable options in mitigated control areas. For example, Fayetteville submits that it finds itself without transmission access to make short-term energy purchases to displace its higher cost generation.[809] Fayetteville contends that Progress Energy's dominant position, as well as Fayetteville's inability to access alternative suppliers due to the inadequacy of Progress Energy's transmission system, gives Progress Energy unmitigated market power.[810]

729. The Carolina Agencies add that, while economic efficiency is a worthy goal in structurally sound markets where participants have ready and equal access to meaningful choices, the idea of economic efficiency cannot justify a mitigated supplier's behavior in a control area where its market power arises from import limitations or other factors that deprive captive LSEs of viable options. Nor can, they claim, the goal of economic efficiency trump the Commission's clear duty to protect customers by ensuring that rates are just, reasonable, and not unduly discriminatory.[811]

730. The Carolina Agencies dispute the claim that there is no need for a ''must offer'' requirement given the Commission's authority to penalize market manipulation. They question whether refusal to sell in the mitigated market would be actionable under the anti-manipulation rules if there is no obligation to offer power to embedded LSEs.[812]

731. NRECA and others ask the Commission to reject the claim that a ''must offer'' requirement would impede a mitigated seller's ability to fulfill its retail crediting obligations.[813] NRECA responds that retail customers can sometimes benefit from cost-based rates; if competition reduces the market price to a seller's marginal cost, no contribution to fixed costs would be recovered. Commenters note that not all utilities are subject to rules requiring the sharing of profits from off-system sales.[814] NRECA argues that a utility's authority to make off-system sales at market-based rates is a privilege granted by the Commission; if the Commission restricts or conditions that privilege, any obligation the public utility has under State law or regulation to sell excess energy or capacity is pre-empted by the requirements of Federal regulation.[815] The Carolina Agencies and NRECA add that a ''must offer'' requirement would serve the intended purpose of the Commission's mitigation policy, which is to protect wholesale customers from the exercise of actual and potential market power, not to preserve a utility's ability to reduce retail rates nor its ability to engage in a certain volume of off-system power sales.[816]

732. NRECA, APPA/TAPS and the Carolina Agencies all set forth proposals in their comments for implementing a ''must offer'' requirement.[817] NRECA suggests requiring a mitigated seller to hold an annual open season to offer long-term service (one year or more), as well as requiring a mitigated seller to offer shorter-term capacity and energy.[818] While not favoring an annual open season, APPA/TAPS and the Carolina Agencies each propose ''must-offer'' parameters to govern short- and long-term sales.[819] For both short- and long-term sales, the Carolina Agencies would offer captive customers an option between (1) Locking-in their price at the mitigated utility's embedded cost rates or (2) agreeing to have their charges determined through an annually updated formula rate that reflects the mitigated utility's actual system-wide average costs.[820] The APPA/TAPS proposal also includes an obligation to offer captive customers participation on proposed generation projects.[821] Both APPA/TAPS and the Carolina Agencies would limit any ''must-offer'' to loads actually located in the mitigated control area.

733. NRECA also proposes two alternatives to a ''must offer'' requirement. First, NRECA suggests that the Commission give captive wholesale customers a right of first refusal to purchase at a market price energy or capacity that the mitigated seller proposes to sell outside the mitigated

[803] *Id.* at 30.

[804] *Id.* at 31.

[805] *Id.* at 30–31.

[806] APPA/TAPS at 6–7; Carolina Agencies reply comments at 6.

[807] APPA/TAPS reply comments at 6–7.

[808] *APPA/TAPS supplemental comments* at 30–31.

[809] Fayetteville reply comments at 5.

[810] *Id.* at 6. *See also* Montana Counsel at 15–23 (where market power is found, sellers should be required to offer power to meet the requirements of dependent customers at cost).

[811] Carolina Agencies reply comments at 9.

[812] Carolina Agencies reply comments at 10–11.

[813] *See, e.g.*, NRECA reply comments at 37–39; Carolina Agencies at 17 (citing April 14 Order, 107 FERC ¶ 61,018 at P 140, 154, where they claim that the Commission rejected arguments that cost-based mitigation rates adversely affect retail rates, because such rates provide for the recovery of the mitigated utility's longer-term costs, and because the adverse impact claims were ''unsupported and speculative.''); Fayetteville reply comments at 7, 9–10.

[814] NRECA reply comments at 38; Carolina Agencies at 8.

[815] NRECA reply comments at 38–39 (citing *Entergy La., Inc.*, v. *La. Pub. Serv. Comm'n*, 539 U.S. 39 (2003); *Miss. Power & Light Co.* v. *Mississippi ex rel. Moore*, 487 U. S. 354 (1988); *Nantahala Power & Light Co.* v. *Thornburg*, 476 U. S. 953 (1986)); *see also* Carolina Agencies reply comments at 7–8 (where a utility is satisfying a countervailing regulatory mandate (such as a ''must offer'' obligation, it cannot be held to be violating the cost minimization duty)).

[816] Carolina Agencies at 17; Carolina Agencies reply comments at 7–8; NRECA reply comments at 35.

[817] NRECA at 35; APPA/TAPS at 40–42; Carolina Agencies at 10–13.

[818] NRECA at 35–36.

[819] APPA/TAPS at 40–42; Carolina Agencies at 10–13.

[820] Carolina Agencies at 12–13.

[821] APPA/TAPS at 41.

market.[822] The weakness of this approach, NRECA acknowledges, is that it would allow the mitigated seller to charge wholesale customers a supra-competitive price in the mitigated market given that the market-based rate outside the control area would be higher than the cost-based rate in the seller's control area.[823]

734. NRECA also suggests as an alternative an enforceable commitment to provide sufficient additional transmission import capacity to mitigate the generation market power. It states that such a commitment could be implemented by re-dispatching resources, relinquishing transmission reservations, or physically upgrading the transmission grid. This would allow additional suppliers to make sales in the mitigated region, thereby mitigating the seller's generation market power. NRECA contends that this approach would directly address the larger issue of the need to eliminate transmission bottlenecks and load pockets that give rise to generation market power.[824]

735. The Carolina Agencies also propose that mitigated utilities be required to investigate and report on transmission expansion or other actions that could remove structural impediments causing market power. The Carolina Agencies claim that such a requirement is consistent with the Commission's affirmative duty to remedy undue discrimination, an area in which the Commission has broad authority to craft remedies.[825]

736. Other commenters argue against imposition of a ''must offer'' requirement, stating that it would encourage inefficiencies, undermine competition, discourage investment, and perpetuate market power. They also assert that such a requirement goes beyond any cost-of-service requirement that the Commission has ever adopted.[826] They question the need for a ''must offer'' requirement, claiming that existing Commission statutory authority, regulations, and enforcement mechanisms already sufficiently guard against the market power abuse and market manipulation concerns that ''must offer'' proponents claim such a provision is needed to prevent.[827]

737. EEI and Progress Energy claim that when the Commission establishes a cost-based rate in a mitigated market, it ensures that the rate meets the just and reasonable and not unduly discriminatory requirements of sections 205 and 206 of the FPA, and thus there is no further Commission action that is required to mitigate the indicated market power.[828]

738. Several commenters that argue against imposition of a ''must offer'' requirement state that wholesale customers have not presented sufficient evidence to justify the generic imposition of such a requirement. They state that there have been no specific instances cited where a wholesale customer in a mitigated market was unable to obtain service, much less evidence that such instances are commonplace.

739. Duke/Progress Energy argue that the Commission must make a finding that rates or practices are unjust, unreasonable, or unduly discriminatory as a predicate to taking action, and that in the case of a generic rulemaking, ''the Commission'' cannot rely solely on ''unsupported or abstract allegations.''' [829] They cite *National Fuel Gas Supply Corp.* v. *FERC*,[830] where the D.C. Circuit, describing *Tenneco Gas* v. *FERC*,[831] stated ''[t]he court [in *Tenneco*] 'upheld Order 497 in relevant part because FERC presented an adequate justification—by advancing both (i) A plausible theoretical threat of anti-competitive information-sharing between pipelines and their marketing affiliates and (ii) vast record evidence of abuse.' ''[832] They note that the D.C. Circuit contrasted *Tenneco* with Order No. 2004 (at issue in *National Fuel*), where '' 'FERC has cited no complaints and provided zero evidence of actual abuse between pipelines and their non-marketing affiliates.' '' They assert that the D.C. Circuit concluded 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 decisionmaking.'' ' [833]

740. According to Duke/Progress Energy, the commenters favoring a ''must offer'' requirement ''have presented *no evidence whatsoever* to support the conclusion that any systemic discrimination is occurring or that any party is suffering any actual harm under the discrimination theory they have posited.'' [834] Duke/Progress Energy offer several examples where they have sold power to LSEs within their control areas after the Commission imposed cost-based mitigation for those sales as evidence that there is no basis for expecting mitigated utilities to abandon long-standing customers and ''decades of intersystem coordination and mutual assistance, whereby utilities take whatever measures are possible * * * to help their neighbors maintain reliability.'' [835]

741. A number of commenters assert that the Commission's statutory authority to require wholesale sales under section 202(b) and 202(c) of the FPA is limited and cannot justify the imposition of a ''must offer'' requirement in this context.[836] Southern explains that the Commission has forced power sales by a jurisdictional public utility to wholesale customers under section 202(b) of the FPA only if such customers have proven they lack service alternatives. Southern states that it would be unreasonable to impose a generic obligation to serve at wholesale by means of a ''must offer'' requirement, absent particularized findings based on a properly developed record that wholesale customers lack reasonable alternatives.[837]

742. EEI agrees that the Commission's section 202(b) authority is clearly aimed at individual transactions where a wholesale customer cannot access supply, with ample due process safeguards to ensure that a requirement to sell is truly warranted and will not

[822] NRECA reply comments at 36–37.

[823] NRECA at 36–37. MidAmerican disagrees, arguing that market-based prices are not by definition always higher than cost-based prices in the mitigated region. Rather, the Commission has encouraged open access transmission and market competition because economically efficient market-based rates can be lower than cost-based rates. At the same time, where a price index at a trading hub may be lower than the seller's incremental cost, MidAmerican argues that a seller should never be required to sell at rates below its incremental cost. MidAmerican reply comments at 21.

[824] NRECA at 37.

[825] Carolina Agencies at 16 (citing the OATT Reform NOPR at P 210 and n.203).

[826] *See, e.g.*, Xcel at 5; Progress Energy reply comments at 5. APPA/TAPS and NRECA respond that as long as the rate is cost-compensatory, and therefore just and reasonable, it provides an adequate return and the mitigated supplier is not disadvantaged by making such sale. APPA/TAPS reply comments at 9; NRECA reply comments at 31, 35, 38.

[827] *See, e.g.*, EEI at 36; Progress Energy at 17.

[828] EEI at 37; Progress Energy at 13.

[829] Duke/Progress Energy supplemental coments at 21 (quoting *Transmission Access Policy Study Group* v. *FERC*, 225 F.3d 667, 688 (D.C. Cir. 2000) (*TAPS*)).

[830] 468 F.3d 831, 840 (D.C. Cir. 2006) (*National Fuel*).

[831] 969 F.2d 1187 (D.C. Cir. 1992) (*Tenneco*).

[832] Duke/Progress Energy supplemental comments at 22 (quoting *National Fuel,* 468 F.3d at 840).

[833] *National Fuel,* 468 F.3d at 843–44.

[834] Duke/Progress Energy supplemental comments at 23 (citing *TAPS,* 225 F.3d at 688, (emphasis in original)); *see also* Xcel reply comments at 6–7 (parties have not provided any supporting rationale that would justify a ''must offer'' requirement over other potential purchasers); EEI supplemental comments at 3 (commenters have failed to demonstrate that there is discrimination warranting generic action).

[835] Duke/Progress Energy supplemental comments at 17 and n.7.

[836] *See, e.g.*, Pinnacle at 8; EEI at 35–36; Progress Energy reply comments at 5, n.5; Duke reply comments at 6.

[837] Southern at 60.

harm the seller.[838] EEI states that the Commission cannot turn such a provision into a blanket regulatory requirement without violating the intent of Congress and inappropriately bypassing these safeguards, nor is such a blanket requirement warranted.[839]

743. Several commenters question the legal support for a ''must offer'' requirement, arguing that the FPA does not contain an express obligation to serve wholesale customers,[840] and that neither section 205 nor section 206 of the FPA authorize the Commission to mandate or prohibit sales, as long as they are made at just, reasonable, and non-discriminatory rates approved by the Commission.[841]

744. Many commenters also contest claims that sales outside the mitigated control area at market-based rates constitute withholding or undue discrimination. Westar and others suggest that offering generation for sale outside of the mitigated control area at the prevailing market price to serve demand does not constitute withholding. They state that withholding generally refers to either physical withholding (not offering to sell) or economic withholding (offering to sell only at inflated prices), which in either case is intended to raise prices.[842] Duke/Progress Energy claim that ''the Commission has confirmed that it is 'legitimate economically rational' behavior for a market participant to export power in order to sell at higher prices outside a control area rather than to sell at lower capped prices within a control area.'' [843] Westar similarly argues that, absent evidence of manipulation or fraud, a '' 'seller of a commodity is acting quite rationally and legally to withhold his supply from the market if he believes that in the future the commodity will command a higher price—assuming, of course, the seller is under no legal duty to sell.' '' [844] Westar and E.ON U.S. reason that the Commission's market behavior rules already address economic withholding concerns.[845]

745. MidAmerican adds that in the limited instances where a wholesale customer cannot obtain service, and where an obligation to serve exists, the Commission can address the issue in fact-specific proceedings of individual sellers.[846] Duke suggests that the ''must offer'' proponents have failed to demonstrate why ''self-supply,'' including new construction and supply from external resources, is not a viable option in at least some instances.[847] Duke states, for example, that the Carolina Agencies submit that LSEs will have few if any practical supply options if a mitigated supplier is not subject to a must offer requirement. However in Duke's view, the Carolina Agencies fail to demonstrate why ''self-supply,'' including construction of local generation by their members, is not a viable option in at least some instances. Nor do they demonstrate lack of ability to secure supply from resources external to the control area. Duke submits that even where construction of new generation may not be cost-effective, ''self-supply'' includes purchasing as well as self-build. Duke argues that lack of an economic self-build option at a given time does not relieve an LSE of its obligation to acquire generation resources through alternate means such as long-term purchases.[848]

746. Several commenters similarly challenge the claim that choosing to make sales outside the mitigated control area at market-based rates is discriminatory. EEI notes that not all rate distinctions are prohibited by section 205(b) of the FPA. It states that only undue discrimination between customers of the same class that is not justified by cost of service differences, operating conditions, or other considerations is forbidden.[849] In this proceeding, Duke/Progress Energy claim that wholesale customers are seeking a *superior* product to that offered to other customers outside the mitigated control area: ''a Commission-enforced right to a free and unilateral call option to buy any available energy generated by [m]itigated [u]tility assets at cost-based prices, exercisable during peak periods when market prices are high.'' [850]

747. EEI adds that the courts also recognize that the just and reasonable standard allows—and can even require—rate differences to reflect different locations and classes of customers.[851] EEI and Progress Energy therefore contend that, once the Commission has determined whether a seller may sell at market-based rates or must use mitigated rates in various markets, the seller must be allowed to sell electricity at the just and reasonable rates approved for the different markets.[852]

748. MidAmerican claims that customer concerns that a mitigated seller will unduly discriminate between the seller's native load and wholesale customers in the mitigated region are baseless because the Commission's jurisdiction does not extend to a comparison of retail and wholesale rates. MidAmerican states that while a seller typically has an obligation to serve retail customers in a franchised service area, that obligation does not extend to wholesale customers. Therefore, MidAmerican states there is no issue of undue discrimination between retail and wholesale rates that either requires or allows a ''must offer'' requirement.[853]

749. Xcel and others submit that wholesale customers are seeking a preference or entitlement through a ''must offer'' requirement and are in fact calling for discrimination by asserting a preference to power available for sale by a mitigated seller over all other

[838] EEI reply comments at 16.

[839] EEI at 35–36 (citing *El Paso Electric Co.* v. *FERC,* 201 FERC F.3d 667 (5th Cir. 2000)).

[840] MidAmerican at 18–19; EEI at 33; Southern at 59; Westar at 17; Duke at 12; E.ON U.S. reply comments at 1–2; Progress at 13.

[841] EEI at 35; Progress Energy at 13–14; E.ON U.S. reply comments at 1–2; Duke reply comments at 5–6.

[842] EEI reply at 2; Duke/Progress Energy at 15.

[843] Duke/Progress Energy at supplemental comments 16 (quoting *San Diego Gas & Elec. Co.*, 103 FERC ¶ 61,345 at P 63 (2003)).

[844] *See* Westar at 11, n.23 (quoting *United States* v. *Reliant Energy Services Co.*, 420 F. Supp. 2d 1043, 1059 (N.D. Cal. 2006)); *see also* EEI at 36.

[845] Westar at 12; E.ON U.S. reply comments at 7. In adopting those rules, Westar submits that the Commission specifically rejected arguments that ''withholding for an anti-competitive purpose *can only be remedied by way of a generic ''must offer''* obligation,'' stating that ''[i]n fact, where a seller intentionally withholds capacity for the purpose of manipulating market prices, market conditions, or markets rules for electric energy or electricity products, it has done so without a legitimate business purpose in violation of Market Behavior Rule 2.'' Westar at 12 (quoting *Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations*, 107 FERC ¶ 61,175 at P 27 (2004) (emphasis added)).

[846] MidAmerican at 19.

[847] Duke reply comments at 10. APPA/TAPS responds that the Commission has recognized that not all LSEs can build their own generation. APPA/TAPS reply comments at 9 (citing April 14 Order, 107 FERC ¶ 61,018 at P 155).

[848] Duke reply comments at 10.

[849] EEI reply comments at 13–14 (citations, including *Wisconsin Michigan Power Co.*, 31 FPC 1445 (1964); *CED Rock Springs LLC*, 116 FERC ¶ 61,163 at P 39 (2006) (In examining potential undue discrimination, the Commission properly focuses on whether ''there are any similarly situated projects that have been treated differently.''); *see also Badger Power Marketing Authority*, 116 FERC ¶ 61,200 at P 10 (2006) (approving a rate that is essentially the same as the rate charged another similarly-situated customer)).

[850] Duke/Progress Energy supplemental comments at 9.

[851] EEI reply comments at 14–15 (citing *Town of Norwood, Massachusetts* v. *FERC*, 202 F.3d 392 at 402 (1st Cir. 2000) (''[D]ifferential treatment does not necessarily amount to undue preference where the difference in treatment can be explained by some factor deemed acceptable by the regulators (and the courts).''); *City of Vernon, California* v. *FERC*, 983 F.2d 1089 at 1093 (D.C. Cir. 1993)).

[852] *Id.* at 15; Progress Energy at 13.

[853] MidAmerican reply comments at 7; *see also*, Duke reply comments at 6. *Compare* APPA/TAPS reply comments at 3 (''The Commission is not called upon to decide a struggle between wholesale and retail ratepayers, but to set a just and reasonable wholesale rate, which a Commission-approved cost-based rate surely is.'').

purchasers, even those who value it more highly,[854] and have provided no evidence to justify such a preference or entitlement over other potential purchasers.[855] Duke/Progress Energy state that customer claims that ''they are victims of market power and therefore need some specially tailored remedy'' is erroneous, and that ''[b]y imposing cost-based rates * * * within their control area, the Commission has fully mitigated any market power concerns.'' [856] Xcel and others also note that the LSEs have no reciprocal obligation to purchase power if a ''must offer'' requirement were imposed upon mitigated sellers.[857]

750. According to Duke and others, when a mitigated supplier sells excess generation at market-based rates outside of the mitigated control area, it is exhibiting economic behavior.[858] Such behavior encourages trading within and across regions, making markets more competitive. Similarly, Westar contends that a ''must offer'' requirement prevents markets from allocating scarce resources to customers who value them the most, hindering optimal resource allocation.[859] Westar states that this is inefficient because ''the highest cost generation may not be displaced by the seller's lower cost energy.'' [860]

751. EEI, Progress Energy, and others also claim that a ''must offer'' requirement would effectively take economic benefits away from the mitigated utility's retail native load and transfer them to wholesale customers in the mitigated control area.[861] Some of these commenters claim that a ''must offer'' requirement may result in a windfall for the wholesale customer originally seeking protection from the seller's market power at the expense of the mitigated utility and its native load customers.[862] PNM/Tucson adds that sales made by a utility pursuant to a ''must offer'' requirement could affect reliability by making capacity unavailable to meet State-established reserve margins.[863]

752. Xcel and Duke point out that a ''must offer'' requirement at cost-based rates may result in a lost opportunity cost to the seller.[864] A number of commenters assert that mitigation is intended to assure that selling utilities do not benefit from the exercise of market power; it is not to guarantee preferential treatment for particular customers to obtain below-market generation through an obligation to serve.[865]

753. Some commenters further contend that a ''must offer'' requirement would create significant wealth transfers from mitigated sellers as a result of arbitrage opportunities. For example, wholesale customers would accept the mitigated offer any time the ''must offer'' price was below the market price, either in or outside of the mitigated region.[866] E.ON U.S. is concerned that a ''must offer'' requirement giving a buyer the option to buy power at mitigated prices will inevitably result in external third parties negotiating with such a buyer to obtain longer-term access to the mitigated power.[867]

754. In addition, EEI and others argue that a ''must offer'' requirement would reduce competition and stifle development by providing a disincentive for sellers to develop new generation resources.[868] New entrants would be deterred from building generation due to the disparity between cost-based and market-based rates; [869] other sellers in the mitigated region effectively would be mitigated because they would not be selected by buyers unless their price is below the mitigated price of the ''must offer'' requirement.[870] At the same time, EEI asserts that the mitigated seller would perpetuate its market power by increasing its capacity in the mitigated control area.[871]

755. Progress Energy and MidAmerican add that a ''must offer'' requirement would impede a mitigated seller's ability to fulfill its retail crediting obligations and to provide adequate and reliable service to its native load retail customers, which bear, through their retail rates, the fixed costs of the generation to serve them.[872]

756. Southern, Duke and others further suggest that a ''must offer'' requirement could undermine the required planning and operations processes of utility systems purchasing the ''must offer'' output.[873] They argue that a ''must offer'' requirement could bias shorter-term operating decisions where, for example, an LSE has the opportunity to purchase peak supply in real time at less than market prices, thereby avoiding incurring any fixed costs on a day-ahead basis to ensure peak supply availability.[874] They contend that this would eliminate incentives for the LSEs to plan to meet their resource needs and shift planning obligations at the expense of a mitigated utility's native load customers.[875]

757. Another commenter is also wary of a ''must offer'' requirement, reasoning that such a requirement is normally designed to mitigate physical withholding. This commenter states that it may work well in an organized power market where an independent operator ensures that the power is used to serve the local needs caused by reliability or local resource deficiency. However, without an independent operator, a ''must offer'' requirement may be more difficult to administer.[876] In advocating for separate market policies and tests for short- and long-term markets, this commenter prefers a price cap for short-term products rather than a ''must offer'' requirement, asserting that a price cap for short-term products is preferable to a ''must offer'' approach because it is more economically efficient, fair, and easier to administer.[877] For long-term products, this commenter takes the position that, ''[i]n situations where a lack of long-term transmission and/or a lack of long-term supply alternatives exist, it is difficult to think of an

[854] Xcel reply at 6–7; EEI supplemental comments at 4–5.

[855] Xcel reply comments at 6–7; Progress Energy reply comments at 2, 4, 7–11; Duke reply comments at 7, n.10.

[856] Duke/Progress Energy supplemental comments at 13 (citing *Duke Power*, 113 FERC ¶ 61,192 at P 22).

[857] Xcel reply comments at 7; Progress Energy reply comments at 6; MidAmerican reply comments at 9.

[858] Duke at 11; Xcel at 6; Southern at 56–57; EEI reply comments at 11.

[859] Westar at 13 (citing *Pacific Gas and Electric Company,* 38 FERC ¶ 61,242 at 61,790 (1987)).

[860] *Id.* (quoting *Pacific Gas and Electric Company,* 38 FERC at 61,790, n.19).

[861] *See, e.g.,* EEI at 33; Progress Energy at 14, 16; Entergy at 2; Westar at 16; *see also* Dr. Pace at 24–25.

[862] PPL reply comments at 14; Duke reply comments at 2, 7–8; Progress Energy at 16; E.ON U.S. at 13–14; Duke at 12–13; MidAmerican at 27.

[863] PNM/Tucson at 18.

[864] Xcel at 8; Duke reply comments at 3, n.4.

[865] Xcel at 5; EEI reply comments at 10, 12; Progress Energy at 14.

[866] Progress Energy at 16; Westar at 16.

[867] E.ON U.S. at 13.

[868] EEI at 37; Progress Energy at 16; MidAmerican at 22. APPA/TAPS responds that it is in fact the mitigated seller's constrained transmission system that keeps LSEs captive and prevents new entry that could reduce the seller's market power. APPA/TAPS reply comments at 9.

[869] EEI reply comments at 10.

[870] MidAmerican reply comments at 8.

[871] EEI reply comments at 10.

[872] *See, e.g.,* Progress Energy at 14–15; E.ON U.S. at 12–13; PNM Tucson at 18; MidAmerican at 21.

[873] Southern at 61; Progress Energy at 16; Duke reply comments at 9–10; EEI reply comments at 10–11.

[874] Southern at 63.

[875] Duke reply comments at 8–11. APPA/TAPS counters that where a ''must offer'' requirement would not, by its own terms, obligate a seller to build, an LSE that relied exclusively on ''must offer'' sales would be taking risks that capacity to support those sales might no longer be available. APPA/TAPS reply comments at 9.

[876] Drs. Broehm and Fox-Penner at 16–17.

[877] Drs. Broehm and Fox-Penner supplemental comments at 3. Drs. Broehm and Fox-Penner advocate other approaches, such as use of a proxy price when transmission constraints are not binding and use of default cost-based rates when they are binding.

alternative to full cost-of-service rates.'' [878] They add that these cost-based rates should offer both fair prices and adequate investment returns to suppliers in the destination market with rate-of-return levels that fully enable incumbent suppliers to make appropriate investments to meet such cost-based obligations.[879]

758. Entergy raises a concern that in the NOPR the Commission erred by failing to define what constitutes available capacity. It asserts that there is difficulty in calculating available capacity because of uncertainty regarding: (1) Loads; (2) qualifying facility puts; (3) unit performance; and (4) fuel arrangements and prices.[880]

Commission Determination

759. After careful consideration of the arguments raised by commenters, we will not impose an across-the-board ''must offer'' requirement for mitigated sellers. While wholesale customer commenters have raised concerns relating to their ability to access needed power, we conclude that there is insufficient record evidence to support instituting a generic ''must offer'' requirement.

760. As discussed above, some commenters argue that undue discrimination occurs if a mitigated seller refuses to sell power to customers in the mitigated balancing authority area and instead sells that power at market-based rates to customers outside the mitigated balancing authority area. Some commenters also contend that it is unduly discriminatory for a mitigated seller to make market-based rate sales to competitive markets outside the mitigated balancing authority area when constraints on that seller's own transmission system prevent embedded customers from similarly accessing those markets as buyers. However, these commenters have not provided any evidence of specific instances in which the harms they identify have, or are, occurring. Without such evidence, we decline to impose a generic remedy such as a ''must offer'' requirement.

761. In *National Fuel*, the D.C. Circuit vacated a final rule of the Commission, Order No. 2004, as applicable to natural gas pipelines because of the expansion of the standards of conduct to include a new definition of energy affiliates. The court explained that the Commission relied on both theoretical grounds and on record evidence to justify this expansion. The court concluded that the Commission's record evidence did not withstand scrutiny and, thus, concluded the expansion was arbitrary and capricious in violation of the Administrative Procedure Act.[881] While the court left open the possibility of the Commission relying solely on a theoretical threat of abuse, it cautioned that if the Commission chooses to take that approach, ''it will need to explain how the potential danger * * * unsupported by a record of abuse, justifies such costly prophylactic rules.'' [882] In addition, the court said the Commission would need to explain why individual complaint procedures were insufficient to ensure against abuse.[883]

762. We find here that, although wholesale customer commenters have raised theoretical concerns that they will be unable to access power absent a ''must offer'' requirement, they have not provided any concrete examples of harm nor explained how the potential harm justifies the generic remedy they seek. Given the lack of evidence in the record that wholesale customers in mitigated markets will be unable to obtain power supplies at reasonable rates, we conclude that there is insufficient basis for instituting a generic ''must offer'' requirement. Indeed, the record includes evidence of utilities continuing to make cost-based sales after loss or surrender of market-based rate authority.[884]

763. In addition, consistent with the guidance provided in *National Fuel,* commenters advocating a generic ''must offer'' have not demonstrated that existing procedures and remedies under the FPA are inadequate to deal with specific cases that may arise. To the contrary, we find that there are potential remedies available on a case-by-case basis to a wholesale customer alleging undue discrimination or other unlawful behavior on the part of a mitigated seller. For example, a wholesale customer can file a complaint pursuant to section 206 of the FPA. It also can bring an action under section 202(b) of the FPA.[885] In addition, it can bring an action pursuant to the statutory prohibition in section 222 of the FPA against market manipulation.

764. While we do not impose a generic ''must offer'' requirement in this Final Rule, we do not rule out the possibility that we might find the imposition of a ''must offer'' requirement, or some other condition on the seller's market-based rate authority, to be an appropriate remedy in a particular case depending on the facts and circumstances, as we have done in the past.[886] We note that the Commission has previously imposed a ''must offer'' requirement as a condition of market-based rate authority for sellers in the California markets.[887] There, the record demonstrated a problem in a limited geographic area that warranted a ''must offer'' remedy to prevent unjust and unreasonable rates from being charged during certain times and under certain conditions. If a wholesale customer were to present specific evidence documenting that a transmission provider either denied the customer's request for transmission service, in violation of the OATT, or was unreasonably delaying responding to a request for transmission service, in violation of the OATT, we might find the imposition of a ''must offer'' requirement on a transmission provider to be an appropriate remedy.[888] As the Commission recently explained in Order No. 890, transmission providers must process requests for transmission service ''as soon as reasonably practicable after receipt'' of such requests [889] and must post performance metrics that are intended ''to enhance the transparency of the study process and shed light on whether transmission providers are processing request studies in a non-discriminatory manner.'' [890] Order No. 890 explained that ''the revised *pro forma* OATT will greatly enhance our oversight and enforcement capabilities by increasing the transparency of many critical functions

[878] *Id.*

[879] *Id.*

[880] Entergy at 2–3.

[881] *National Fuel,* 468 F.3d at 844.

[882] *Id.*

[883] *Id.*

[884] *See* Duke reply comments at 7 and n.10; Progress Energy reply comments at 9–11; Duke/Progress Energy supplemental comments at 17 and n.7.

[885] *See, e.g, City of Las Cruces, New Mexico* v. *El Paso Electric Co.,* 87 FERC ¶ 61,220 (1999) (''In our view, section 202(b) allows the Commission to direct a public utility to take three separate actions: (1) Establish a physical connection of its transmission facilities with the facilities of one or more eligible persons; (2) sell energy to eligible persons; or (3) exchange energy with eligible persons.'')

[886] If an intervenor believes a ''must-offer'' requirement is the only way to mitigate market power, it may present evidence to that effect in a particular proceeding.

[887] *See San Diego Gas & Elec. Co.,* 95 FERC ¶ 61,418 at 62,557 (2001) (''After carefully considering the record, the Commission reaffirmed its general finding that, as a result of the seriously flawed electric market structure and rules for wholesale sales of electric energy in California, unjust and unreasonable rates were charged and could continue to be charged during certain times and under certain conditions, unless certain targeted remedies were implemented.'')

[888] We are not prejudging here that such facts warrant imposition of a ''must offer'' requirement.

[889] *Preventing Undue Discrimination and Preference in Transmission Service,* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 1296 (2007) (Order No. 890).

[890] *Id.* at P 1308.

under the *pro forma* OATT, such as ATC calculation and transmission planning.'' [891] Here too, we reiterate that the Commission ''intends to use its enforcement powers with respect to the OATT in a fair and even-handed manner, pursuant to the principles set forth in the Policy Statement on Enforcement.'' [892]

765. In addition to our conclusion that there is not sufficient record evidence to support the imposition of a generic ''must offer'' requirement, we are also concerned that adoption of a ''must offer'' requirement would present a number of difficult implementation and logistical problems.[893]

766. For example, given the difficulties associated with calculations of available transfer capability,[894] we foresee similar disputes over the calculation of available generation capacity were we to impose a generic ''must offer'' obligation. For instance, how far in advance should such calculations occur—one hour, one day, one month, or some other time frame? Would such calculations be derived on a generator specific basis or on a system basis (and how is transmission factored in)? Would the Commission or the industry need to develop a standard method of calculating available generation capacity? How would available generation capacity be allocated to potential purchasers?

767. We also are concerned that adopting a ''must offer'' requirement could harm other markets. For example, if a mitigated seller is required to offer its available power first to customers in the mitigated market, such a requirement may effectively preclude the mitigated seller from participating in adjoining markets particularly at times when additional supply is most needed (*i.e.*, when prices in the adjoining market are high). Such a policy may serve to assist one set of customers at the expense of other customers that see their supply options reduced.

768. Parties have asserted that imposing a must offer requirement may discourage long-term planning, while others have disagreed with those arguments. Given that we do not impose any must offer obligation in this rule, we need not and do not address these arguments. If the Commission considers imposing a ''must offer'' requirement in an individual case, affected parties can raise these arguments at that time.

769. Though APPA/TAPS and the Carolina Agencies are correct that the Commission has previously imposed a ''must offer'' requirement as a condition of market-based rate authority for sellers in the California markets, as discussed above, that holding supports our approach here. There, the record demonstrated a problem in a limited geographic area that warranted a ''must offer'' remedy to prevent unjust and unreasonable rates from being charged during certain times and under certain conditions. By contrast, here APPA/TAPS and the Carolina Agencies urge us to impose a generic remedy on all mitigated sellers in all markets without a showing that there is a concrete problem justifying imposition of a ''must offer'' requirement in all markets.

770. Given that we have not adopted a ''must offer'' requirement in this Final Rule, we need not, and do not, address arguments asserting that we lack legal authority to do so. If the Commission should adopt any such requirement in an individual case, affected parties can raise any related legal arguments at that time and nothing in this rule precludes them from doing so.

771. For many of the same reasons that we decline to impose a ''must offer'' requirement, we also decline to adopt the ''right of first refusal'' requirement proposed by NRECA. Under this approach, a wholesale customer in the mitigated market would be given a right of refusal to purchase, at the market price, power that the mitigated seller proposes to sell outside the mitigated market. For the reasons provided above, there is insufficient record evidence to support imposition of such an across-the-board requirement.

772. A ''right of first refusal'' also would carry significant administrative burdens. Such an approach would invite disputes about what constitutes a legitimate offer by a third party to purchase power which establishes the basis for the offered rate. There also may be disputes if more than one wholesale customer wants to purchase the power in question. We are also concerned about the long-term viability of a rate setting that is based on mitigated sellers repeatedly negotiating tentative power sale arrangements with would-be buyers in first-tier markets only to have those offers withdrawn so the sale could be made to another buyer. Under such a regime, buyers from outside the mitigated market may be disinclined to invest resources to negotiate tentative contracts knowing that there is a significant chance that another buyer from within the mitigated market will usurp their position and instead get the sale.

773. There are also administrative concerns with how the Commission or third parties could be certain what the actual price and conditions of service would be for the sale in the first-tier market unless the contract was actually executed.

774. In response to NRECA's suggestion that an enforceable commitment to provide sufficient additional transmission import capacity to mitigate generation market power be considered as an alternative, the Commission notes that, consistent with the April 14 Order, a seller that fails one of the generation market power screens is allowed to propose alternative mitigation that the Commission may deem appropriate.[895] As a result, a mitigated seller could propose, as alternative mitigation, to provide additional transmission capacity by, for example, committing to relinquish transmission reservations or to physically upgrade the transmission grid.[896] The Commission would consider such proposals on a case-by-case basis. Moreover, a primary purpose of Order No. 890 is to ''increase the ability of customers to access new generating resources and promote efficient utilization of transmission by requiring an open, transparent, and coordinated transmission planning process.'' [897]

775. In particular, we believe recent actions we took in Order No. 890 address the Carolina Agencies' proposal that mitigated utilities be required to investigate and report on transmission expansion or other actions that could remove structural impediments exacerbating market power. In Order No. 890, the Commission adopted a number of reforms designed to mitigate transmission market power, including a requirement that all transmission providers develop a coordinated, open and transparent transmission planning process that would, among other things, enable customers to request studies evaluating potential upgrades or other investments that could reduce congestion or integrate new resources and loads.[898] The requests for these

[891] *Id.* at P 1721.

[892] *Id.* at P 1714.

[893] Because we have decided not to impose a generic ''must offer'' requirement in this Final Rule, we do not address the merits of the particular must-offer proposals made by commenters.

[894] OATT Reform NOPR at PP 37–41 (outlining problems that result from inconsistent available transfer capacity calculation, including missed opportunities for transactions, frequent errors, and undue discrimination).

[895] April 14 Order, 107 FERC ¶ 61,018 at P 147, 148 n.142.

[896] *See, e.g., Westar Energy, Inc.,* 115 FERC ¶ 61,228, *order on reh'g,* 117 FERC ¶ 61,011 (2006), *order on further reh'g,* 118 FERC ¶ 61,237 (2007) (concerning such mitigation proposed in the context of a disposition of jurisdictional facilities).

[897] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 3.

[898] *Id.* at P 544.

economic planning studies and the responses will be posted on the transmission provider's OASIS site, subject to confidentiality requirements.[899] We believe these steps may assist in reducing structural impediments that contribute to market power.

b. First-Tier Markets

Commission Proposal

776. In the NOPR, the Commission sought comment on whether it is appropriate to continue to allow sellers that are subject to mitigation in their home control area to sell power at market-based rates outside their control area. The Commission asked if this represents undue discrimination or otherwise constitutes ''withholding'' in the home control area that is inconsistent with the FPA's mandate that rates be just, reasonable and not unduly discriminatory, or, instead, if this reflects economically efficient behavior and encourages necessary trading within and across regions, particularly in peak periods when marginal prices rise above average embedded costs.

777. The Commission also asked if it should find that any seller that has lost market-based rate authority in its home control area should be precluded from selling power at market-based rates in adjacent (first tier) control areas.

Comments

778. A number of commenters state that there is no basis for prohibiting a mitigated seller from selling excess power at market-based rates in adjacent control areas, as the Commission will have determined that the seller does not have the ability to exercise market power in any of those adjacent control areas.[900] Some commenters also claim that prohibiting these sales would limit market activity and constrain the benefits of competitive pricing by excluding sellers from markets in which they do not possess market power.[901]

779. PNM/Tucson contends that prohibiting sales of available capacity at market-based rates in adjacent control areas where the seller does not possess market power would be a disproportionate response that would render the Commission's market-by-market analysis meaningless.[902] Moreover, PNM/Tucson and MidAmerican warn that independent power producers have no incentive to invest in new resources in markets where prices are effectively constrained to the level of another entity's embedded costs.[903]

780. Southern asks the Commission not to impose mitigation that will create flaws in markets that may have periods of genuine temporary scarcity but where the seller does not possess market power.[904] Southern states that prohibiting a mitigated seller from responding to price signals in neighboring markets will adversely affect efficient resource development and contradicts the Commission's desire to promote competitive markets and resource adequacy.[905] Further, foreclosing markets otherwise accessible to resources nominally dedicated to native load service may impair the optimization of those resources by impairing a full response to price signals. This, Southern adds, would harm native load customers because the mitigated utility would be unable to optimize surplus resources, as mandated through State retail credit obligations, thereby depriving retail customers of the benefits of system optimization.[906]

781. Another commenter agrees that a mitigated seller should be allowed to sell available capacity at market-based rates in markets where that seller does not possess market power, provided that this does not raise prices in the mitigated region.[907] This commenter asserts that such sales facilitate regional trading and market efficiency in developing competitive markets.[908] Another commenter contends that unless ''costs'' are defined in a way that effectively allows competitive market rates to be charged, revoking a seller's market-based rate authority in markets where the seller does not possess market power would reduce the mitigated seller's incentive to supply available power to the market, deprive the mitigated seller and its customers of legitimate economic rent, subsidize those buyers with access to the mitigated rates, and create a rationing problem among buyers with access to the mitigated-rate power.[909]

782. MidAmerican states that, if the Commission were to eliminate a seller's market-based rate authority in all regions, the mitigated prices should only apply prospectively. MidAmerican reasons that existing transactions negotiated in the absence of market power should not be altered, since these previously-negotiated transactions would have no impact on a seller's willingness to make future sales to customers in the home control area.[910]

783. Other commenters oppose allowing mitigated sellers to sell at market-based rates outside the home control area on the basis that it encourages and provides incentives for the seller to engage in physical or economic withholding of its generation output in the home control area. These commenters indicate that their concerns in this regard would be addressed if mitigation is combined with a requirement that the mitigated seller make power available to customers within the mitigated control area. APPA/TAPS state that, absent a ''must offer'' requirement, it is not clear that prohibiting mitigated sellers from making market-based sales outside their home control areas would necessarily prompt the mitigated seller to sell power in its home control area.[911]

784. However, APPA/TAPS ask the Commission not to rule out across-the-board revocation of market-based rate authority as it may be necessary to motivate mitigated sellers to undertake the kind of structural measures needed to mitigate market power on a long-term basis. If the Commission adopts a policy to revoke or condition market-based rate authority beyond the home control area, APPA/TAPS state that the policy should not be limited to just the first-tier control area. Rather, the revocation or conditions should apply to any market where the seller can use generation located in or originally delivered to its control area to sell outside that mitigated area.[912]

785. The Carolina Agencies state that a generic prohibition on market-based rate sales outside the mitigated market

[899] *Id.* at P 546 (to be codified at 18 CFR 37.6(b)(2)(iii)).

[900] Ameren at 18–19; *see also* Duke at 12 (citing *Florida Power Corp.,* 113 FERC ¶ 61,131 at P 24 (2005)); Southern at 56; PNM/Tucson at 19–20 ; Xcel at 5–6; EEI at 33; and PPL reply comments at 15–16.

[901] MidAmerican at 22–23; PPL at 24–25; EEI at 28.

[902] PNM/Tucson at 19–20.

[903] MidAmerican at 22, PNM/Tucson at 17.

[904] Southern at 64–65.

[905] *Id.* at 57.

[906] *Id.*

[907] Drs. Broehm and Fox-Penner at 16. The NYISO also supports market-based rate sales in competitive markets where the mitigated seller does not possess market power. According to the NYISO, with regard to the NYISO, PJM Interconnection, LLC and ISO-New England, the Commission can ensure that sellers respond to market price signals by designing market power mitigation in a manner that will permit even mitigated sellers to receive the applicable market clearing price. For example, any cost-based rate mitigation imposed could limit the maximum bids that the seller may submit without limiting the revenues that the mitigated seller may receive. NYISO at 10.

[908] Drs. Broehm and Fox-Penner at 16. *See also* PPL at 24; MidAmerican at 17; E.ON U.S. at 12–13; EEI at 28; Duke at 11.

[909] Dr. Pace at 21.

[910] MidAmerican at 23.

[911] APPA/TAPS at 43.

[912] APPA/TAPS at 43–44.

appears likely to inhibit regional trade to a greater extent than is necessary to protect the interests of embedded LSEs.[913] Both the Carolina Agencies and NC Towns state that there is no clear need to prohibit mitigated sellers from making market-based sales outside their home control areas if a ''must offer'' requirement is adopted.[914] According to the Carolina Agencies, a mitigated seller should be free to engage in market-based rate sales in other control areas as long as that utility has provided embedded LSEs a reasonable opportunity to purchase capacity and/or energy.

786. As to any claim that it would be unduly discriminatory for the Commission to deny or condition the market-based rate authority of a utility that passes the screens in markets beyond its mitigated home control area, APPA/TAPS and the Carolina Agencies submit that mitigated sellers are not similarly-situated to the other utilities selling at market-based rates in those other competitive markets. They assert that other sellers' market-based rate sales do not implicate those sellers' ability to withhold supply from disfavored wholesale customers in a mitigated control area. Moreover, they argue that it elevates the importance of the screens above the FPA to argue that granting unconditioned market-based rate authority to one seller who passes the screens obligates the Commission to grant unconditioned authority to all who pass the screens. In their view, the Commission would be failing its duty under the FPA if it permitted physical withholding by a dominant utility, as such actions would be unjust, unreasonable, and unduly discriminatory.[915]

787. ELCON advocates suspending any mitigated seller's market-based rates in all markets it can access. Short of this long-term fix, ELCON asserts that other proposals such as ''must offer'' requirements will be prone to fail because of likely unintended consequences.[916]

788. Morgan Stanley favors requiring mitigated sellers to post the mitigated price and other material terms on a publicly-available Web site for all sales to be made from the units that are part of the portfolio covered by the Commission's market power finding, regardless of where the actual sale sinks.[917] Morgan Stanley asserts that effective mitigation can only occur if it is imposed on all sales from a mitigated supplier's generation portfolio and urges the Commission not to focus on who the purchaser is or where the power sinks.[918] If a mitigated seller chooses to offer its excess power only outside the mitigated region and simply refuses to sell inside its home market, Morgan Stanley is concerned that the market in the ''home'' territory would be even less competitive than if the seller were allowed to sell there on an unmitigated basis.[919]

789. CAISO states that, where a competitive supply of imports into a mitigated control area does not exist, market power mitigation mechanisms or other incentive schemes will be necessary to ensure that the local supplier makes all of its capacity available to supply energy and ancillary services to the home control area.[920] CAISO asks the Commission to provide greater clarity on the extent to which the antifraud and anti-manipulation rules adopted in Order No. 670 prohibit economic and physical withholding of resources. In particular, CAISO asks the Commission to provide greater clarity on the deceptive conduct criteria it would use to determine whether a particular case of physical or economic withholding would be a violation of the new Part 47 regulations. CAISO explains that greater clarity in this area will help ISO and RTO market monitors in developing effective RTO/ISO market power mitigation rules tailored for the types of physical and economic withholding that are not addressed under Part 47 regulations.

Commission Determination

790. After careful consideration of the arguments raised by commenters, we will retain our current policy and limit mitigation to the market in which the seller has been found to possess, or chosen not to rebut the presumption of, market power. We will not place limitations on a mitigated seller's ability to sell at market-based rates in balancing authority areas in which the seller has not been found to have market power.

791. The Commission authorizes sales of electric energy at market-based rates if the seller and its affiliates do not have, or have adequately mitigated, horizontal and vertical market power in generation and transmission, and cannot erect other barriers to entry. As the Commission has explained, ''The consideration of market power is important in determining if customers have genuine alternatives to buying the seller's product.'' [921] Commenters favoring revocation of a mitigated seller's market-based rate authority in markets where there has been no finding of market power, as well as those supporting broadening mitigation to first-tier markets, have not provided a sufficient legal basis for such a policy. Where the record demonstrates that a seller does not have market power in a market, or has adequately mitigated any market power, the Commission has authorized such a seller to transact under market-based rates.[922] As the April 14 Order explained, ''Market-based rates will not be revoked and cost-based rates will not be imposed until there has been a Commission order making a definitive finding that the applicant has market power * * *'' [923]

792. We recognize that wholesale customer commenters are generally concerned that allowing mitigated sellers to sell outside their mitigated markets at market-based rates could encourage such sellers not to offer generation for sale within the mitigated market. However, we agree with the Carolina Agencies that a generic prohibition against such sales could inhibit regional trade to a greater extent than necessary to protect captive LSEs. We note that even some wholesale customer commenters acknowledge that it is not clear that prohibiting mitigated sellers from making market-based sales beyond their mitigated region would prompt the mitigated seller to sell power in the mitigated market. For these reasons, we limit mitigation to the areas in which the seller has market power.

793. For the reasons stated above, we disagree with Morgan Stanley's assertion that effective mitigation can only occur if it is imposed on all sales from a mitigated seller's generation portfolio. In addition, though we appreciate CAISO's request for greater clarity on the criteria the Commission

[913] Carolina Agencies at 19.

[914] *Id.* at 18–19; NC Towns at 7.

[915] APPA/TAPS and Carolina Agencies supplemental comments at 36–37. NRECA adds that ''the FPA does not bar—as unduly discriminatory—Commission imposition of remedies in a non-discriminatory fashion, including banning sales outside the mitigated market: the statute protects buyers, not sellers, from undue discrimination.'' NRECA reply comments at 41; *see also* Carolina Agencies at 16 (citing the OATT Reform NOPR at P 210 and n.203).

[916] ELCON at 11.

[917] Morgan Stanley at 7; Morgan Stanley reply comments at 6.

[918] Morgan Stanley reply comments at 6. The Oregon Commission responds that such broad mitigation would not benefit wholesale customers in the mitigated region and would harm the supplier's native retail load by transferring wealth to marketers like Morgan Stanley. Oregon Commission reply comments at 4; *see also* MidAmerican reply comments at 13–14 (arguing that Morgan Stanley's proposal would be an arbitrary and capricious redistribution of income and allow windfall arbitrage profits).

[919] Morgan Stanley at 6.

[920] CAISO at 16.

[921] *Louisville Gas & Elec. Co.,* 62 FERC at 61,144.

[922] *Florida Power Corp.,* 113 FERC ¶ 61,131 at P 24.

[923] April 14 Order, 107 FERC ¶ 61.018 at P 149.

will use to determine whether economic and physical withholding has occurred, such a determination must be made on a case-by-case basis.

c. Sales That Sink in Unmitigated Markets

Commission Proposal

794. In the NOPR, the Commission stated that some companies have proposed limiting mitigation to sales that ''sink in'' the mitigated market, that is, so that mitigation would only apply to end users in the mitigated market. However, in *MidAmerican Energy Company,*[924] the Commission stated that limiting mitigation to sales that ''sink in'' the mitigated market would improperly limit mitigation to certain sales, namely, only to sales to buyers that serve end-use customers in the mitigated market. The Commission reasoned that limiting mitigation in this manner would improperly allow market-based rate sales within the mitigated market to entities that do not serve end-use customers in the mitigated market.[925] The Commission stated that such a limitation would not mitigate the seller's ability to attempt to exercise market power over sales in the mitigated market and is inconsistent with the Commission's direction in the April 14 and July 8 Orders. On rehearing of the April 14 Order, it was argued that access to power sold under mitigated prices should be restricted to buyers serving end-use customers within the relevant geographic market in which the seller has been found to have market power. In particular, arguments were made that a seller should not be required to make sales at mitigated prices to power marketers or brokers without end-use customers in the relevant market. In the July 8 Order, the Commission rejected the suggestion that mitigated sellers be restricted to selling power only to buyers serving end-use customers, and has since rejected tariff language that proposes to do so.

795. In the NOPR, the Commission sought comment on whether it should modify or revise its current policy. The Commission sought comment on whether and, if so, how it should allow market-based rate sales by a mitigated seller within a mitigated market if those sales do not ''sink'' in that control area.

Comments

796. While some commenters generally seek to allow a mitigated seller to make sales at market-based rates if those sales do not ''sink'' in the mitigated market, other commenters support the current policy of requiring all of a mitigated supplier's sales in the mitigated market to be cost-based. The State AGs and Advocates go even further and encourage the Commission to apply its mitigation policy to all wholesale sales that sink in the mitigated market, regardless of the seller, arguing that the impact of market power on price is market-wide in scope.[926]

797. APPA/TAPS support the current policy of requiring cost-based rate mitigation for all sales in the mitigated market regardless of whether the sales ultimately sink in an unmitigated market. APPA/TAPS argue that allowing market-based rate sales in a mitigated market would yield unlawful rates because the mitigated seller would be making market-based rate sales in a market where it has, or is presumed to have, market power.[927]

798. The NYISO agrees that mitigation should not be limited to sales that ''sink in'' the mitigated market, at least in clearing price auctions such as those administered by the NYISO. The clearing prices are established by the interaction of all eligible buyers and sellers, and the NYISO reasons that there would be no practical basis, nor economic justification, for carving out marketers or brokers who may export their purchases.[928]

799. The Carolina Agencies express concern that limiting mitigation to sales that sink in a mitigated market would reduce supply options for LSEs embedded in that mitigated market. They contend that unrestricted exports from a mitigated market increase the prices charged by other sellers due to scarcity. Even when a sale sinks outside the mitigated market, the Carolina Agencies claim that round-trip gaming will continue, and they question the Commission's ability to effectively detect and stop such gaming by attempting to trace megawatts via NERC tag data or other means. However, the Carolina Agencies submit that with a properly structured ''must offer'' requirement in place, there is no reason to bar market-based rate sales based on the location of the point of sale or even the identified sink.[929]

800. Other commenters support allowing sales of power within a mitigated market that nonetheless sink in unmitigated markets (*i.e.*, markets where the seller does not possess market power) to be made at market-based rates.[930] As discussed below, they offer various proposals on what factors should determine whether a sale should be priced at market-based rates.

801. Several commenters state that the relevant inquiry should be whether the power serves load (sinks) in a control area where generation market power is an issue. MidAmerican and the Oregon Commission submit that there is no reason to mitigate sales over which the seller is unable to exercise market power.[931] Rather, MidAmerican asks the Commission to refocus on whether a seller could exercise market power, not on the physical location where a change in ownership of energy occurs. MidAmerican argues that if a mitigated seller cannot exercise market power over sales made directly in an outside competitive market, such seller cannot exercise market power over sales made in its home control area that are for export to that outside competitive market.[932] Rather than protecting the ultimate buyers, these commenters submit that mitigating such sales would transfer wealth from the mitigated seller to subsequent entities that can charge market prices in later transactions.[933]

802. MidAmerican and the Oregon Commission claim that if the Commission requires mitigated sellers to mitigate all their sales in the mitigated market such an outcome would encourage gaming, such as round-trip or ricochet transactions.[934] MidAmerican maintains that such gaming can be eliminated when mitigation applies only to sales sinking within the mitigated control area.[935]

803. Duke, E.ON U.S., Westar, Mid-American, Ameren, and Xcel all assert that the availability of supply alternatives to wholesale purchasers should be a determining factor when deciding whether to permit market-based rates for sales that sink in

[924] 114 FERC ¶ 61,280 at P 29–33 (2006), *reh'g pending (MidAmerican).*

[925] *Id.* at P 31.

[926] State AGs and Advocates at 43–44.

[927] APPA/TAPS at 47–48. To limit marketers' arbitrage opportunities, APPA/TAPS suggest limiting any ''must offer'' obligation to sales that sink in the seller's control area. The seller could make additional sales in its control area at the cost-based rate, but would not be obligated to do so because purchasers for loads outside of the seller's control area would presumably have other power supply options.

[928] NYISO at 8–10. The NYISO suggests that the Commission can avoid concerns regarding exports to neighboring markets by applying any cost-based mitigation it imposes to limit the maximum bids that the seller may submit, without limiting the revenues that the mitigated seller may receive. *Id.*

[929] Carolina Agencies at 20.

[930] *See, e.g.*, PPL reply comments at 16.

[931] MidAmerican at 26; Oregon Commission reply comments at 5; *see also* Westar at 20.

[932] MidAmerican at 25–26; *see also* Dr. Pace at 18–20.

[933] MidAmerican at 26; Oregon Commission reply comments at 5.

[934] MidAmerican at 26–27; Oregon Commission reply comments at 6.

[935] MidAmerican at 27.

unmitigated markets.[936] E.ON U.S. points out that the Commission in the April 14 Order noted that the foundation of the market power analysis under the Delivered Price Test is the ''destination market.'' As such, E.ON U.S. asserts that a relevant factor in determining whether to permit a sale at market-based rates should be the level of choice in supply available to the purchaser, not where the product originates.[937]

804. Westar contends that when the buyer is purchasing to serve load in control areas where the seller lacks market power, the buyer presumably has access to other competitive alternatives and has voluntarily entered into the agreement. Therefore, the Commission should not second guess the buyer's decision.[938] Westar adds that prohibiting all sales in the mitigated control area elevates form over substance because parties can simply alter the implementing details of their transaction to accomplish the same result.[939]

805. Westar argues that the Commission's stated concern in *MidAmerican* with a seller's ''ability to attempt to exercise market power over sales in its control area'' is misplaced; the Commission's traditional market power analysis is only concerned with the ''incentive'' and ''ability'' to exercise market power, not with ''attempts'' to do so.[940] As such, it is ''ability'' and not ''attempts'' to exercise market power that is a key determinant of whether an actual market power problem exists.

806. Westar further claims that the Commission is not bound by precedent to prohibit all market-based rate sales in a mitigated control area, pointing out that the Commission has accepted four proposals after the July 8 Order that limit mitigation to sales that sink in the mitigated control areas.[941] Moreover, Westar claims that the July 8 Order appears to address the question of who may buy power from a mitigated seller, not where mitigated sales can occur. This leads Westar to conclude that the Commission did not originally intend to preclude mitigated sellers from making market-based sales to buyers over which the seller lacks generation market power, regardless of where the sales occur. Westar urges the Commission to return to this principle.[942]

807. Xcel urges the Commission to focus on the parties' intent and whether alternative supply options are available to the purchaser at the time of contracting, rather than focusing on where energy purchased in the transaction actually sinks in real time. At the time of the transaction, if the purchaser can confirm: (i) It intends to use the power outside of the mitigated control area, and (ii) there are existing transmission arrangements to actually use the power elsewhere, Xcel maintains that it should not matter what the purchaser subsequently does with the power in real time.[943] Xcel and MidAmerican also favor adopting market-index or proxy based mitigation as a way to reduce the concern about where sales actually sink when trying to ensure proper mitigation.[944]

808. EEI, PPL, PNM/Tucson, and Pinnacle take the position that the Commission should consider point of delivery when deciding whether to permit market-based rate sales.[945] EEI asks the Commission to allow mitigated sellers to make market-based rate sales if the delivery point in the contract or sale confirmation is outside the mitigated market, or if the buyer has transmission service to take the power outside the mitigated market. In other words, buyers who choose delivery points inside the mitigated market and do not move the power out will pay mitigated rates, but buyers who choose delivery points inside the mitigated market but move the power outside the mitigated market will pay market-based rates.[946]

809. EEI asserts that its proposal is consistent with the Commission policy that the mitigation must focus on the geographic market that is mitigated, not the type of customer purchasing the power. EEI concludes that the proposal will minimize the impacts on competitive transactions as well as avoid a remedy that will have a negative impact on the liquidity of the competitive market.[947]

810. PNM/Tucson agree that the Commission should use the point of delivery as a determining factor. They contend that transmission tags alone—which they explain are a reliability tool to ensure systems balance from a transmission perspective—are inadequate to monitor market transactions or ensure that sales sink outside a mitigated control area.[948]

811. PNM/Tucson, Pinnacle, E.ON U.S., MidAmerican and PPL all generally argue that sales at or beyond the transmission interface of a mitigated control area should not be mitigated if the seller lacks market power in the adjacent control area.[949] MidAmerican asserts that the Commission's market power analyses demonstrate that the seller has no market power over sales at the border (sales requiring no additional transmission to exit the mitigated region).[950] PNM/Tucson, Pinnacle and E.ON U.S. maintain that prohibiting market-based rate sales at these transmission interfaces would prevent cross border sales at these unique locations and reduce market liquidity in markets where the seller does not possess market power.[951]

812. E.ON U.S. and MidAmerican urge the Commission to view interface/border transactions as fundamentally different from sales in, or sinking in, a control area. These commenters reason that, at transmission interfaces, a buyer has competitive choices from sellers in both control areas that abut the interface, as well as from any seller that can transmit power to that interface from any control area. As a result, buyers taking title to power at a

[936] Duke at 13; E.ON U.S. at 6; Westar at 20; MidAmerican at 25; Ameren at 19–20; and Xcel at 13.

[937] E.ON U.S. at 6.

[938] Westar at 20.

[939] *Id.* at 21.

[940] *Id.* at 21 (citing *MidAmerican Energy Company,* 114 FERC ¶ 61,280 (2006), *reh'g pending*; *Exelon Corp.*, 112 FERC ¶ 61,011, at P 134 (''As we have said in numerous contexts, we are concerned about a merger's effect on the merged firm's ability and incentive to harm competition.''), *order on reh'g,* 113 FERC ¶ 61,299 (2005); *Oklahoma Gas and Electric Company,* 105 FERC ¶ 61,297, at P 35 (2003) (''Both the ability and incentive to raise prices by restricting access are necessary for a vertical market power problem to exist.''); *NiSource Inc.*, 92 FERC ¶ 61,068, at 61,239 (2000) (''Because the merged company must have both the ability and incentive to adversely affect electricity prices or output, and the merged company will lack the former, no further findings are necessary.'')).

[941] *Id.* at 22 (citing *American Electric Power Service Corp.*, Docket Nos. ER96–2495–026, *et al.* (Jan. 13, 2006) (letter order accepting uncontested settlement applying mitigation to sales that sink in the mitigated control area); *AEP Power Marketing, Inc.*, 112 FERC ¶ 61,320 (2005) (dismissing rehearing requests as moot because of utility's commitment to mitigate sales ''that sink within AEP-SPP''); *South Carolina Electric and Gas Company,* 114 FERC ¶ 61,143 (2006) (order accepting utility's commitment to mitigate sales that ''sink'' in its home control area, subject to a compliance filing); *LG&E Energy Marketing, Inc.*, 113 FERC ¶ 61,229 (2005) (ordering the utility to apply the proposed mitigation to sales that sink in the mitigated control area)).

[942] Westar at 22–23.

[943] Xcel at 13. While MidAmerican does not object to Xcel's proposal, it submits that its own proposal regarding use of market-based indices would provide additional assurance that a seller would not manipulate prices by arranging round-trip transactions into a mitigated control area. MidAmerican reply comments at 19–20.

[944] Xcel at 11–138; MidAmerican reply comments at 4.

[945] EEI at 38; PPL at 25 (supporting EEI's comments); Pinnacle at 9; PNM/Tucson at 14–15.

[946] EEI at 38.

[947] EEI at 41.

[948] PNM/Tucson at 14–15.

[949] PNM/Tucson at 16; Pinnacle at 8–9; E.ON U.S. at 5–8; MidAmerican at 29–30; PPL reply comments at 16.

[950] MidAmerican at 29–30.

[951] PNM/Tucson at 16; Pinnacle at 8–9; E.ON U.S. at 8.

transmission interface for delivery outside the mitigated control area have competitive choices that do not require transacting with the supplier found to have market power within the mitigated control area(s).[952] Moreover, E.ON U.S. claims that mitigating transactions at control area interfaces could reduce a utility's profits from off-system sales, thereby affecting retail ratepayers by reducing offsets that affect the costs of their retail rates.[953]

813. PNM/Tucson, Pinnacle, E.ON U.S., and MidAmerican note that the Commission indicated in *LG&E* that sales at the border need not be mitigated along with sales ''wholly in'' a control area.[954] PNM/Tucson and MidAmerican urge the Commission to codify in the Final Rule *LG&E's* holding that sales at the transmission interface of a mitigated control area are not ''in'' the control area, and therefore need not be mitigated.[955] E.ON U.S. similarly asks the Commission to define sales ''in'' a control area as those where title to power transfers at a physical location wholly within such control area, and should not include sales where title transfers at a transmission interface.[956]

814. Xcel, in comparison, argues that any buyer purchasing power at a generator bus or elsewhere in a mitigated control area for purposes of moving that power out of the mitigated market should be treated no differently than a buyer who takes delivery of purchased power outside of the mitigated region. According to Xcel, mitigation to discipline market power is unnecessary in either of these cases and the location of the delivery point does not matter.[957]

815. Both Dalton Utilities and the Carolina Agencies state that it would be wrong to assume that every contract involving a mitigated supplier is unjust and unreasonable and must be abrogated to protect consumers.[958] Dalton Utilities urge the Commission to clearly state in the final rule that it does not generically abrogate existing long-term market-based rate wholesale requirements and transmission contracts, nor is it requiring such abrogation in subsequent proceedings that revoke the market-based rate authority of a public utility found to possess market power.[959] Dalton Utilities asks the Commission to grandfather existing long-term market-based wholesale contracts in the final rule.[960]

816. The Carolina Agencies add that the effect on existing contracts of a decision to retain the current mitigation policy of prohibiting sales at market-based rates in a mitigated market should be determined on a case-by-case basis. These entities reason that simply because market power may exist (or a presumption that it exists has not been rebutted) does not in every instance mean that the seller actually abused its market position to extract unreasonable terms from its purchaser. The circumstances of each contract must be examined to determine whether its terms reflect the exercise of market power. The Carolina Agencies and Dalton Utilities conclude that generic abrogation or reformation of existing agreements is neither warranted nor consistent with the Commission's manner of resolving other claims of broad-based discrimination.[961]

Commission Determination

817. In order to protect customers from market power concerns, we will continue to apply mitigation to all sales in the balancing authority area in which a seller is found, or presumed, to have market power. However, as discussed below we will allow mitigated sellers to make market-based rate sales at the metered boundary[962] between a mitigated balancing authority area and a balancing authority area in which the seller has market-based rate authority under certain circumstances.

818. Commenters advocating allowing market-based rate sales in a mitigated market provided the power is intended for an unmitigated market (*e.g.*, applying mitigation only to sales that sink in the mitigated market) have failed to adequately explain how customers in the mitigated market would be protected from the potential exercise of market power. In addition, commenters have failed to adequately address how the Commission could effectively monitor such sales to ensure that improper sales were not being made. Indeed, several commenters have noted the complex administrative problems that would be associated with trying to monitor compliance with such a policy.[963]

819. Allowing market-based rate sales by a seller that has been found to have market power, or has so conceded, in the very market in which market power is a concern is inconsistent with the Commission's responsibility under the FPA to ensure that rates are just and reasonable and not unduly discriminatory. While we generally agree that it is desirable to allow market-based rate sales into markets where the seller has not been found to have market power, we do not agree that it is reasonable to allow a mitigated seller to make market-based rate sales anywhere within a mitigated market. It is unrealistic to believe that sales made anywhere in a balancing authority area can be traced to ensure that no improper sales are taking place. Such an approach would also place customers and competitors at an unreasonable disadvantage because the mitigated seller has dominance in the very market in which it is making market-based rate sales.

820. However, we do recognize that sales made at the metered boundary for export do lend themselves to being monitored for compliance, and the nature of these types of sales do not unduly disadvantage customers or competitors. Prohibiting market-based rate sales at these metered boundaries of the balancing authority area could prevent or adversely impact cross border sales at these unique locations and reduce market liquidity in markets where the seller does not possess market power. Buyers taking title to power at a metered boundary for delivery to serve load in a balancing authority area where the seller has market-based rate authority have competitive choices and therefore are not required to transact with the seller found to have market power within the mitigated balancing authority area(s).

821. Accordingly, we will allow such sales to be made at market-based rates. Mitigated sellers making such sales must maintain for a period of five years from the date of the sale all data and information related to the sale that demonstrates that the sale was made at the metered boundary between the mitigated balancing authority area and a balancing authority area in which the seller has market-based rate authority, that the sale is not intended to serve load in the seller's mitigated market,

[952] E.ON U.S. at 6; MidAmerican reply comments at 22–23.

[953] E.ON U.S. at 8.

[954] PNM/Tucson at 16; Pinnacle at 8–9; E.ON U.S. at 8; MidAmerican reply comments at 23.

[955] PNM/Tucson at 16; MidAmerican reply comments at 23.

[956] E.ON U.S. at 5.

[957] Xcel at 12.

[958] Dalton Utilities reply comments at 4–9; Carolina Agencies at 22–23.

[959] Dalton Utilities reply comments at 6, 9.

[960] *Id.* at 6–7. Duke notes its support for the Commission's current policy of not reforming or abrogating contracts that were negotiated prior to the time of any finding of market power. Duke reply comments at 8, n.12.

[961] Carolina Agencies at 23; Dalton Utilities reply comments at 7–9.

[962] North American Electric Reliability Corporation. *Glossary of Terms Used in Reliability Standards* at 2 (2007), available at *ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May07.pdf.*

[963] For example, PNM/Tucson note that transmission tags alone are inadequate to monitor market transactions. PNM/Tucson at 14–15.

and that no affiliate of the mitigated seller will sell the same power back into the mitigated seller's mitigated market.

822. Such an approach properly balances commenters' concerns that when a buyer purchases power to serve load in markets where the mitigated seller lacks market power the buyer has access to competitive alternatives with the Commission's obligation under the FPA to ensure that rates are just and reasonable. Further, we find that our approach in this regard does not place an unreasonable burden on the customer, mitigated seller, or competitors. We also emphasize that the mitigation we adopt herein is prospective only. In response to Dalton's concern, we clarify that such mitigation does not modify, abrogate, or otherwise affect existing contractual agreements.[964]

823. Further, we disagree with the Carolina Agencies' contention that short of a ''must-offer'' provision unrestricted exports from a mitigated market increase the prices charged by other suppliers due to scarcity. Carolina Agencies' argument would only apply when the market prices in the first-tier markets are higher than the seller's cost-based rate in the mitigated market. This situation is not necessarily always the case and, therefore, the Carolina Agencies' concern may be based on an unrealistic assumption.

824. We disagree with MidAmerican and the Oregon Commission's claim that if the Commission requires mitigated sellers to mitigate all their sales in the mitigated market this would encourage gaming, such as round-trip or ricochet transactions. While the Commission issued an order rescinding Market Behavior Rules 2 and 6,[965] Order No. 670 finalized regulations prohibiting energy market manipulation pursuant to the Commission's new Energy Policy Act of 2005 authority. The Commission emphasized in Order No. 670 that ''the specific prohibitions of Market Behavior Rule 2 (wash trades, transactions predicated on submitting false information, transactions creating and relieving artificial congestion, and collusion for the purpose of market manipulation), * * * are examples of prohibited manipulation, all of which are manipulative or deceptive devices or contrivances, and are therefore prohibited activities under this Final Rule, subject to punitive and remedial action.'' [966] Such fraud and manipulative conduct therefore remains prohibited and subject to the Commission's anti-manipulation and civil penalty authority.

d. Proposed Tariff Language

Comments

825. Several commenters have proposed specific tariff language in the event the Commission allows market-based rate sales in the mitigated market or at the border. For example, PNM/Tucson would require a sale to ''have a contractual point of delivery at or beyond the transmission interface of the mitigated control area (assuming that the point of delivery is not in another control area where the seller is also mitigated).'' [967] They would also require the seller's market-based rate tariff to explicitly prohibit efforts to collude with a third party to sell to customers in the mitigated control area at market-based rates.[968]

826. PNM/Tucson point out that their proposal contains a significant concession. Under their proposed language, a sale by a mitigated seller at the generation bus in the mitigated control area must be made at mitigated rates. They believe this concession is fair if the Commission insists that market-based rate sales for mitigated sellers are based on contractual points of delivery at or beyond the transmission interface of the mitigated control area. In these companies' view, such an approach would provide needed certainty through a bright line rule and limit factual disputes and investigations.[969]

827. MidAmerican and Ameren also support using tariff or agreement language to ensure power sinks outside of the mitigated market.[970] MidAmerican favors using tariff safeguards and confirmation/oversight procedures to mitigate a seller's ability to exercise generation market power, prevent gaming, and protect wholesale customers in the mitigated region. MidAmerican submits that it has developed and filed market-based rate tariff provisions and verification and oversight procedures that can ensure that export transactions sink outside the mitigated seller's control area.[971] MidAmerican argues that its approach correctly focuses on whether the mitigated seller could exercise market power over transactions that affect entities that purchase on behalf of, or for re-sale to, loads within the market subject to mitigation, rather than the geographical location where customers may take responsibility for transmitting the power to a final destination. Moreover, MidAmerican claims that its proposal would allow the market to work efficiently in areas where the mitigated seller's ability to exercise market power is not an issue. MidAmerican supports a Commission technical conference to further explore this concept with interested parties.[972]

828. Several commenters further propose that mitigated sellers be required to add language to their market-based rate tariffs or to specific market-based rate contracts to restrict re-sales from sinking in the mitigated control area.[973] FP&L argues that requiring such language would reinforce the idea that re-sales into mitigated control areas are violations of a Commission-approved tariff that also, depending on the facts, might violate the Commission's market manipulation regulations.[974]

829. Another commenter agrees that restrictive language in the market-based rate tariff could prevent re-sales into the mitigated control area by helping to ensure that any power purchased at market-based rates within a mitigated control area is exclusively for export to serve loads beyond the mitigated market. Where the Commission is concerned that gaming could lead to the

[964] *See South Carolina Electric and Gas Co.*, 114 FERC ¶ 61,143 at P 18 (2006) (accepting mitigation on a prospective basis; existing long-term agreements remain in effect until terminated pursuant to their terms); *see also* April 14 Order, 107 FERC ¶ 61,018 at P 154; July 8 Order, 108 FERC ¶ 61,026 at P 145.

[965] *Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations*, 114 FERC ¶ 61,165 (2006).

[966] *Prohibition of Energy Market Manipulation*, Order No. 670, 114 ¶ FERC 61,047 at P 59 (2006).

[967] PNM/Tucson at 15.

[968] *Id.*

[969] *Id.* at 16–17; MidAmerican submits that its proposal would also provide the ''bright-line'' regulatory certainty sought by PNM/Tucson. MidAmerican reply comments at 16–18.

[970] MidAmerican at 28; Ameren at 19–20.

[971] Under MidAmerican's proposed tariff revisions: (i) Counterparties would be required to affirmatively confirm that the energy sold within MidAmerican's control area will not stay inside that control area; (ii) MidAmerican energy schedulers will review NERC tags associated with in-control area sales on a daily basis to ensure transactions indeed sink outside the mitigated control area; (iii) if a review of the NERC tags shows that a transaction will sink inside the mitigated control area, the sale will be renegotiated at cost-based rates; and (iv) if required by the Commission, MidAmerican would submit the NERC tag data to the appropriate market monitor. MidAmerican at 28–29.

[972] MidAmerican at 28–29.

[973] FP&L at 6 (proposing the following tariff language: ''Purchasers are hereby on notice that the sink for any energy or capacity sale under this Tariff shall not be in the Seller's control area.''); E.ON U.S. at 10 (proposing ''a simple tariff commitment by sellers that power sold at a point of delivery within their mitigated control area will, to the best of their knowledge, sink elsewhere.''); Ameren at 20 (proposing that agreements governing market-based rate sales in mitigated markets explicitly state that the subject power will sink outside the mitigated region, and that the seller be required to report such sales in its EQR).

[974] FP&L at 6.

exercise of market power over wholesale customers in the home control area, this commenter suggests that the Commission reemphasize that efforts to loop power through an adjacent market area in order to raise prices to wholesale customers in mitigated areas above competitive levels is a violation of market-based rate tariffs. Further, this commenter submits that the Commission may require buyers to confirm that power purchased at market-based rates in a mitigated control area is for export, use NERC tag data and transmission scheduling information to verify when purchased power is being exported from the home control area, and require oversight by independent market monitors.[975]

Commission Determination

830. Consistent with our decision above, mitigated sellers choosing to make market-based rate sales at the metered boundary between a mitigated balancing authority area and a balancing authority area in which the seller has market-based rate authority will be required to commit and maintain sufficient documentation to demonstrate[976] that: (1) Legal title of the power sold transfers at the metered boundary between a mitigated balancing authority area and one in which the mitigated entity has market-based rate authorization; and (2) any power sold is not intended to serve load in the seller's mitigated market and (3) no affiliate of the mitigated seller will sell the same power back into the mitigated seller's mitigated market. To accomplish these requirements, mitigated sellers seeking to make market-based rate sales at the metered boundary between their mitigated balancing authority area and a balancing authority area in which the sellers have market-based rate authority must adopt the following tariff provision:

Sales of energy and capacity are permissible under this tariff in all balancing authority areas where the Seller has been granted market-based rate authority. Sales of energy and capacity under this tariff are also permissible at the metered boundary between the Seller's mitigated balancing authority area and a balancing authority area where the Seller has been granted market-based rate authority provided: (i) Legal title of the power sold transfers at the metered boundary of the balancing authority area where the seller has market-based rate authority; (ii) any power sold hereunder is not intended to serve load in the seller's mitigated market; and (iii) no affiliate of the mitigated seller will sell the same power back into the mitigated seller's mitigated market. Seller must retain, for a period of five years from the date of the sale, all data and information related to the sale that demonstrates compliance with items (i), (ii) and (iii) above.

831. This approach affords necessary protection from market power abuse for customers in the mitigated markets. Such language reminds all sellers that gaming resulting in re-sales of any sort by an affiliate of the mitigated seller into their mitigated balancing authority area(s) (*i.e.*, by looping power through adjacent markets) are violations of a Commission-approved tariff that may also, depending on the facts, violate the Commission's market manipulation regulations. Such violations may result in penalties being imposed under the market manipulation regulations and/or the revocation of a mitigated seller's market-based authority in all markets.

### *E. Implementation Process*

Commission Proposal

832. In the NOPR, the Commission put forth several proposals to streamline the administration of the market-based rate program while maintaining a high degree of oversight. The Commission proposed to modify the practice of requiring an updated market power analysis to be submitted within three years of any order granting a seller market-based rate authority and every three years thereafter by, instead, putting in place a structured, systematic review based on a coherent and consistent set of data. First, the Commission proposed to establish two categories of sellers with market-based rate authorization. Sellers in the first category, Category 1,[977] would not be required to file a regularly scheduled updated market power analysis. The Commission proposed instead to monitor any market power concerns for Category 1 sellers through the change in status reporting requirement and through ongoing monitoring by the Commission's Office of Enforcement. In this regard, the Commission noted that failure to timely file a change in status report would constitute a violation of the Commission's regulations and the seller's market-based rate tariff.

833. Sellers in Category 2, consisting of all sellers that do not qualify for Category 1, would be required to file regularly scheduled updated market power analyses in addition to change in status reports. The Commission proposed to codify this requirement in its regulations. Failure to timely file an updated market power analysis would constitute a violation of the Commission's regulations and the seller's market-based rate tariff.

834. Second, to ensure greater consistency in the data used to evaluate Category 2 sellers, the Commission proposed that the required updated market power analyses be filed for each seller's relevant geographic market(s) on a schedule allowing examination of the individual seller at the same time that the Commission examines other sellers in the relevant markets and contiguous markets within a region from which power could be imported. The Commission appended a proposed schedule for the regional review process, rotating by geographic region with three regions being reviewed per year. For corporate families that own or control generation in multiple control areas and different regions, the Commission proposed that the corporate family would be required to file an update for each region in which members of the corporate family sell power during the time period specified for that region.

835. Finally, the Commission proposed to require that all updated market power analyses and all new applications for market-based rate authority include an appendix listing all generation assets owned or controlled by the corporate family by control area, listing the in-service date and nameplate and/or seasonal ratings by unit, and all electric transmission and natural gas intrastate pipelines and/or gas storage facilities owned or controlled by the corporate family and their location.

#### 1. Category 1 and 2 Sellers

Comments

a. Establishment of Category 1 and 2 Sellers

836. A variety of commenters fully support the Commission's proposed categorization of sellers into two categories and the boundaries of those categories. ELCON comments that the Commission's limited resources should be focused on the dominant players and not treat every seller as a potential threat. NRECA commends the Commission for its attempt to

[975] Dr. Pace at 20–21.

[976] Reliance solely on NERC tag data as documentation for such sales will likely be deemed insufficient as such an approach has not yet been shown to be either workable or effective.

[977] Category 1 sellers would include power marketers and power producers that own or control 500 MW or less of generating capacity in aggregate and that are not affiliated with a public utility with a franchised service territory. Category 1 sellers also must not own or control transmission facilities other than limited equipment necessary to connect individual generating facilities to the transmission grid (or must have been granted waiver of the requirements of Order No. 888 because the facilities are limited and discrete and do not constitute an integrated grid), and they must not present other vertical market power issues. NOPR at P 152.

streamline the process.[978] APPA/TAPS support the proposed categories but suggest that the Commission clarify that it retains the ability to determine that a Category 1 seller must still adhere to the triennial update requirements if, for example, it is dominant in a particular load pocket. Explaining that its generation and power marketing activities are only incidental to its mining operations, and that its market share will likely decline over time, Newmont states that filing an updated market analysis every three years would be an unnecessary burden to prepare and a waste of the Commission's time to review. Newmont finds the 500 MW cutoff a clear, bright line that would be easy to administer. If the Commission determines it necessary to adjust the threshold, however, Newmont suggests retaining the 500 MW cutoff with a further requirement that no more than 250–300 MW be located in any one control area. Alternatively, there could be some sliding scale delineation between Categories 1 and 2 based on the size of a control area, in terms of load, unaffiliated capacity, or both.

837. Financial Companies and Morgan Stanley request that the Commission release a list of all sellers in each category and the region in which the Commission believes each seller belongs to help ensure that sellers have notice of their status and related filing obligations. These parties also suggest that the Commission hold a technical conference on commenters' proposals about how to organize the categories.

838. FirstEnergy opposes the concept of exempting Category 1 sellers from triennial reporting while continuing the requirement for Category 2 sellers. FirstEnergy states that there is no reason for the Commission to require any public utility authorized to sell at market-based rates to file an updated market power analysis. According to FirstEnergy, the showing made in the initial market-based rate proceeding and the change in status rules are adequate, and relieving Category 1 sellers from filing without abolishing the requirement entirely would be unduly discriminatory.

839. On the other hand, the California Commission believes that all sellers should have to continue filing updated market power analyses; it states that the assumption that Category 1 sellers do not need the same level of scrutiny as larger sellers is erroneous, and argues that the NOPR provides no legitimate justification for creating a disparity between Category 1 and 2 sellers. The California Commission continues by stating that reliance solely on market monitoring would not necessarily be effective in California. It notes that in markets utilizing LMP, there is a great potential for sellers to exert ''local'' market power, especially in load pockets. In such load pocket areas, it contends that there is no guarantee that a small seller could not have market power. Further, it states that a Category 1 seller could suddenly gain market power due to another seller's withdrawal from the market and asserts that ''given the number of markets and the Commission's limited resources, it would seem an enormous task of monitoring without requiring regular updated market power analyses from all market participants.'' [979]

840. Similarly, NASUCA states that there is no basis in the record to assume that Category 1 sellers would lack market power at all times and offers examples of when Category 1 sellers could pose a problem.[980] NASUCA also warns that there is no apparent limit on the total amount of exempt generation that could be owned by entities other than those affiliated with a franchised utility. Specifically, NASUCA argues that:

> [U]nder the [Category 1] definition and [change of status] notice obligations, a ''Category 1'' seller could qualify for exemption from triennial market power reviews even if its holding company affiliates—other power marketing and generation entities that also have ''Category 1'' status—collectively have a share of generation far larger than 500 MW, and even if the seller has a retail affiliate without a franchised service territory. Examples might include a group of ''Category 1'' peaker plant owners in a constrained area, each owned by a separate entity affiliated with the same holding company; owners of a fleet of small hydro facilities, each a separate entity within a holding company structure; or an assemblage of generation control [sic] by numerous power marketing subsidiaries, each of which controls less than 500 MW of generation.[981]

841. Thus, NASUCA argues that the regulations should be modified or clarified to prevent this scenario. If the Commission proceeds with its proposal, NASUCA states that the Commission should consider a much lower threshold, such as 75 MW.

842. State AGs and Advocates state that exempting entities, no matter how small, would conflict with the concept that all sellers contribute in varying degrees to the existence of market power in a market.[982]

843. NASUCA and the California Commission argue that none of the proponents of an exempt category of sellers have shown how the exemption meets the Commission's legal requirements.[983] NASUCA expresses concern that the blanket exemption for Category 1 sellers from filing updated market power reviews is inconsistent with the justification the Commission has previously made to the courts in support of market-based rates, namely, that the Commission makes a discrete finding or determination as to each seller's market power, and periodically reviews it. The California Commission similarly disputes that the exemption meets the underlying principle found in *Lockyer.* It states that the Ninth Circuit in that case noted that the Commission's authority to grant market-based rates is rooted in the integral nature of the reporting requirements. The California Commission asserts that the proposed requirement for Category 1 sellers to make a filing only upon a change in status is inconsistent with the rationale laid out in *Lockyer.* It further contends that delegation of ongoing monitoring to the Commission's Office of Enforcement is vague and contrary to the underlying principle found in *Lockyer.* According to the California Commission, the assumptions underlying the proposed Category 1 exemption (that since Category 1 sellers are smaller in size they do not need to be subject to the same requirements and scrutiny as larger sellers of energy, and that '' 'Category 2 sellers are the larger sellers with more of a presence in the market and are more likely to fail one or more of the indicative screens or pass by a smaller margin than Category 1 sellers'' ') are insufficient to justify a departure from the *Lockyer* rationale.[984]

844. PPM refutes the California Commission's arguments. First, PPM asserts that the California Commission is wrong in its generalization that a seller that controls less than 500 MW in a market that utilizes LMP could exert

[978] *See also* EPSA reply comments at 3, 13–14.

[979] California Commission at 4.

[980] For example, NASUCA asserts that there appears to be a possibility that a seller with a fleet of newer power plants that were initially exempted from review would be totally exempt from subsequent review based on the size of the power plants. These sellers might at times have market power with respect to ancillary services. NASUCA further submits that changed circumstances, such as declining reserve margins, might create opportunities for seemingly small sellers to exercise market power.

[981] NASUCA at 12. *See also* NASUCA reply comments at 9–11 (stating that neither the 500 MW exemption, nor the expansion to a 1000 MW exemption, nor the elimination of a horizontal market power test, should be adopted).

[982] State AGs and Advocates reply comments at 14.

[983] NASUCA reply comments at 9–11, California Commission reply comments at 1–4.

[984] California Commission reply comments at 3–4 (quoting NOPR at P 153).

local market power. PPM argues that the existence of an LMP market does not increase the potential for a small generator or marketer to possess market power; LMP is intended to reduce the ability of a party to exercise local market power.[985] Second, PPM states that the California Commission is wrong when it asserts that *Lockyer* requires the Commission to require all sellers to file updated market power analyses. According to PPM, in *Lockyer,* the Court found that if the Commission is going to grant parties the authority to charge market-based rates, the Commission must continue to monitor and ensure that the rates charged are just and reasonable. PPM submits that creating a categorical exemption to reduce the burden on smaller generators and marketers does not mean that the Commission is eliminating its ability to effectively monitor the wholesale electric market. It states that the Commission retains the tools necessary to ensure that all rates are just and reasonable: all entities with market-based rate authority must submit electric quarterly reports to the Commission regarding their transactions; all parties have the right to ask the Commission for relief under section 206 of the FPA if they believe that rates are improper or unjust; the Commission may take up an independent review of any markets which are displaying abnormal characteristics; and finally, the Commission may require certain parties to file updated market power analyses if the seller is found to have market power even if the seller meets the threshold for Category 1 exemption.

b. Threshold for Category 1 Sellers and Other Proposed Modifications

845. While the majority of commenters support the concept of exempting smaller, Category 1 sellers from filing updated market power analyses, many seek clarification or modification of the proposal. A number of commenters propose a threshold other than ownership or control of 500 MW or less in aggregate. Suggested thresholds include: 500 MW or less of uncommitted capacity (therefore including only that which is available for sale into markets during peak periods); [986] 500 MW within a particular control area; [987] 500 MW within a geographic market; [988] 500 MW within a particular region; [989] up to 1000 MW; [990] less than 1 percent of the installed capacity in a regional market or 1000 MW in that regional market (whichever is higher); [991] or some other formula.[992] Several commenters urge the Commission to consider the size of a particular control area or geographic region or market and whether the geographic market is served by an RTO/ISO,[993] and to take into account the difference between thermal generating capacity and intermittent or non-dispatchable generation for their ability to impact the competitiveness of a market.[994]

846. PPM argues that without certain modifications to the Commission's definition of a Category 1 seller, which PPM believes is too narrowly defined, many generators and marketers may needlessly have to submit an updated market power analysis. According to PPM, the Commission should not eliminate the exemption for new generation (pursuant to 18 CFR 35.27(a)) without expanding the group of generators and marketers eligible for Category 1 status.[995] Several commenters also urge the Commission to allow fact-specific requests for exemption from filing requirements for those sellers who otherwise would qualify as Category 2 sellers [996] or other particular exemptions.[997]

847. In addition, Constellation proposes specific modifications to the proposal. First, Constellation requests that the Commission change the affiliation standard in the definition of Category 1 sellers to be consistent with other definitions set forth in the NOPR. Because the proposed language would exclude from the definition of Category 1 sellers any affiliate of a public utility with a franchised service territory regardless of whether it has captive customers, Constellation suggests using the defined term ''franchised public utility'' [998] instead of ''public utility with a franchised service territory.'' Constellation states that the exclusion should only apply to affiliates of public utilities with captive customers. Second, Constellation argues that a company should be considered to be a Category 1 seller so long as it is not affiliated with a ''franchised public utility'' in the same geographic region. It explains that, with this change, a company would qualify as a Category 1 seller in California despite the fact that it is affiliated with a franchised public utility in New England because any concerns about affiliate abuse would exist only in the New England market and not in California.[999] Third, Constellation suggests that, if operational control over transmission facilities has been transferred to an RTO/ISO, then a seller's affiliation with the owner of such transmission facilities should not exclude the seller from qualifying as a Category 1 seller. Further, Constellation seeks clarification that the exclusions for owners of transmission facilities that are simply interconnection facilities, are under operational control of an RTO/ISO, or are subject to waiver of Order No. 888 and 889, will also apply to affiliates of those transmission owners.

Commission Determination

Adoption of Category 1/Category 2

848. We adopt the NOPR proposal to create a category of sellers that are exempt from the requirement to automatically submit updated market power analyses, with certain modifications. As discussed further

[985] PPM reply comments at 1–3.

[986] *See* Ormet at 9.

[987] *See, e.g.,* PPM at 3–4; AWEA at 3–4.

[988] *See* Constellation at 8–9 (noting that this would be consistent with the Commission's indicative screen analysis and regional approach to updated market power analyses).

[989] EPSA at 36–37; AWEA at 3–4; Suez/Chevron at 5–10.

[990] *See* Morgan Stanley at 10–13; Financial Companies at 13–14; Financial Companies reply comments at 7–8. *See also* Mirant at 12 (recommending 1000 MW per geographic market if the Commission hopes to have a minimal impact on sellers' compliance costs caused by eliminating the 18 CFR 35.27(a) exemption).

[991] EPSA at 36–37.

[992] Constellation at 9–11 (supports changing threshold from 500 MW to the greater of 500 MW or 2 percent of the total generation capacity in the relevant geographic market; where the geographic market is an RTO or ISO, change threshold to the greater of 1,000 MW or 2 percent of the total generation capacity in that market); Ameren at 21 (supports exempting a company that owns or controls more than 500 MW but owns or controls less than 20 percent of the total uncommitted capacity in the relevant geographic market and also is not affiliated with an entity that owns transmission facilities in that market).

[993] Drs. Broehm and Fox-Penner at 13; Constellation at 9; PPM at 3–4.

[994] AWEA at 3–4 (asserting that companies owning or controlling thermal generating capacity have a greater opportunity for impacting the competitiveness of a market than those that own or control non-dispatchable generation, such as wind power facilities, that rarely achieve production at nameplate capacity levels); PPM at 4 (same); Financial Companies reply comments at 8–9.

[995] PPM at 3–5.

[996] *See* Morgan Stanley; Financial Companies.

[997] *See, e.g.,* Ormet at 7–11 (exemption for self use/supply, *i.e.,* capacity used to self supply a corporate affiliate and presumptively unavailable for sale into markets); TXU at 4–5 (case-by-case determination of whether a seller's affiliation with an entity that owns or controls Commission-jurisdictional transmission presents the possibility of vertical market power concerns).

[998] Proposed 18 CFR 35.36(a)(5) defines a franchised public utility as ''a public utility with a franchised service obligation under state law and that has captive customers.''

[999] Similarly, Constellation contends that, if a seller and its affiliates own more than 500 MW of generation capacity in only one region and less in others, then the seller should be required to file updated market power analyses in only the region(s) where its affiliated generation exceeds the threshold.

below, this finding is fully consistent with our statutory obligation to ensure just and reasonable rates and with court decisions construing that obligation. Moreover, it will streamline the administration of the market-based rate program by focusing the Commission's resources on sellers that have a significant presence in the market. It also is supported by the majority of commenters in this proceeding.

849. The Commission agrees with Financial Companies and Morgan Stanley that sellers should have notice of their status and related filing obligations. However, we believe the criteria we adopt herein are sufficiently clear so that the vast majority of sellers can easily determine in which category they fall. Accordingly, the Commission will not initially compile and release a list of sellers in each category. Rather, we will require all sellers that believe they fall into Category 1 to make a filing with the Commission at the time that updated market power analyses for the seller's relevant market would otherwise be due (based on the regional schedule for updated market power analyses adopted in this Final Rule). That filing should explain why the seller meets the Category 1 criteria[1000] and should include a list of all generation assets (including nameplate or seasonal capacity amounts) owned or controlled by the seller and its affiliates grouped by balancing authority area.[1001] The Commission will notice these filings and provide an opportunity for comment. The Commission will then act on the seller's filing, either acknowledging that the seller falls within Category 1 or, if it finds that the seller does not qualify as a Category 1 seller, directing the seller to file an updated market power analysis. Subsequently, all Category 1 sellers will not be required to file regularly scheduled updated market power analyses.

850. With regard to sellers that fall into Category 2, these sellers will be required to file an updated market power analysis based on the schedule in Appendix D. In our orders acting on the updated market power analyses, the Commission will make a finding that the seller is a Category 2 seller, as appropriate.

851. In addition, with regard to new applications for market-based rate authority, we also will make a finding regarding the category in which the seller falls. However, all sellers submitting initial applications for market-based rate authority must submit the indicative screens, or accept a presumption of market power in generation, and must submit a vertical market power analysis.

852. We reject FirstEnergy's argument that there should be no requirement for any seller to file an updated market power analysis. Competitiveness of markets is continuing to change and, therefore, we are reluctant to rely only on initial market power analyses, change in status filings, and section 206 complaints in all cases. The burden on Category 2 sellers is small compared to their market presence and activities, and is outweighed by the fact that submission of periodic updated market power analyses enhances Commission oversight and public confidence in the regulatory process. Thus, we will require the submittal of regularly scheduled updated market power analyses by those sellers that have more of a presence in the market and are more likely to either fail one or more of the indicative screens or pass by a smaller margin than those that will qualify as Category 1 sellers, or that may present circumstances that could pose vertical market power issues, *i.e.*, Category 2 sellers. Through regularly scheduled updated market power analyses for Category 2 sellers, the Commission is better able to evaluate the ongoing reasonableness of those sellers' charges and to provide for an ongoing assessment of their ability to exercise market power. In the absence of regularly scheduled updated market power analyses from the Category 2 sellers, it would be more difficult for the Commission to fulfill its statutory duty to ensure that market-based rates are just and reasonable and that market-based rate sellers continue to lack the potential to exercise market power so that market forces are indeed determining the price.

853. Because Category 1 and 2 sellers occupy different postures in terms of their presence in the market, it is not unduly discriminatory to eliminate the requirement to file a regularly scheduled updated market power analysis for Category 1 sellers but not Category 2 sellers. Category 1 sellers have been carefully defined by the Commission to have attributes that are not likely to present market power concerns: ownership or control of relatively small amounts of generation capacity; no affiliation with an entity with a franchised service territory in the same region as the seller's generation facility; little or no ownership or control of transmission facilities and no affiliation with an entity that owns or controls transmission in the same region as the seller's generation facility; and no indication of an ability to exercise vertical market power. Further, based on a review of past Commission orders, we are aware of no entity that would have qualified as a Category 1 seller under this Final Rule but would nevertheless have failed our indicative screens necessitating a more thorough analysis. Thus, the Commission has provided a reasoned basis to distinguish Category 1 sellers from Category 2 sellers. Moreover, the EQR reporting requirements and change in status filings required for Category 2 market-based rate sellers will also apply to Category 1 sellers. This will ensure adequate oversight of Category 1 sellers, even without regularly scheduled updated market power analyses. Further, we will continue to reserve the right to require an updated market power analysis from any market-based rate seller at any time, including for those sellers that fall within Category 1.

854. In this regard, we agree with PPM that the Commission retains the tools necessary to ensure that all rates are just and reasonable, including initial market power evaluations, and ongoing monitoring by the Commission. For example, as noted above, all sellers with market-based rates must file electronically with the Commission an EQR of transactions no later than 30 days after the end of the reporting quarter and must comply with the change in status reporting requirement. We note that the reporting requirement relied upon by the court in *Lockyer* is the transaction-specific data found in EQRs, which we continue to require of all sellers, and not updated market power analyses. Thus, exempting Category 1 sellers from routinely filing updated market power analyses does not run counter to *Lockyer.*

855. With respect to EQR filings, the Commission enhanced and updated the post-transaction filing requirements from what they were during the period at issue in the Lockyer case, now requiring electronic reporting of, among

[1000] These criteria, as modified in this Final Rule, include wholesale power marketers and wholesale power producers that own or control 500 MW or less of generation in aggregate per region; that do not own, operate or control transmission facilities other than limited equipment necessary to connect individual generating facilities to the transmission grid (or have been granted waiver of the requirements of Order No. 888); that are not affiliated with anyone that owns, operates or controls transmission facilities in the same region as the seller's generation assets; that are not affiliated with a franchised public utility in the same region as the seller's generation assets; and that do not raise other vertical market power issues.

[1001] In the section titled ''Regional Review and Schedule'' we discuss further how we implement this approach.

other things:[1002] (1) A summary of the contractual terms and conditions in every effective service agreement for market-based power sales; and (2) transaction information for effective short-term (less than one year) and long-term (one year or greater) market-based power sales during the most recent calendar quarter. We also note that the Commission has revoked the market-based rate authority of sellers that have failed to comply with the EQR filing requirements.[1003] Further, the Commission has utilized EQR data in determinations relating to market power. For example, the Commission relied in part on EQR data in reaching its determination that an ''alternative'' market power analysis submitted by Duke Power was unpersuasive.[1004]

856. With respect to notices of change in status, in a related rulemaking proceeding in early 2005, the Commission clarified and standardized market-based rate sellers' reporting requirement for any change in status that departs from the characteristics the Commission relied on in initially authorizing sales at market-based rates.[1005] In Order No. 652, the Commission required that, as a condition of obtaining and retaining market-based rate authority, sellers must file notices of such changes no later than 30 days after the change in status occurs.[1006] These requirements are codified in our regulations, and failure of a market-based rate seller to timely file a change in status report constitutes a tariff violation. If such a violation occurs, the Commission has the tools available to impose remedies, as necessary and appropriate, from the date on which the tariff violation occurred. Such remedies could include disgorgement of profits, civil penalties or other remedies the Commission finds appropriate based on the specific facts and circumstances.

857. We note that any new market-based rate seller must conduct a horizontal market power analysis for our review. Furthermore, we reiterate that the Commission retains the ability to require an updated market power analysis from any seller, Category 1 or 2, at any time.

858. We also reject those arguments made by the California Commission, NASUCA, and State AGs and Advocates that all sellers should continue to be required to file regularly scheduled updated market power analyses. For the reasons stated above, assertions that the Commission will be unable to monitor market-based rate sellers without requiring all sellers to file regularly scheduled updated market power analyses are unfounded.

859. In response to the comments of NASUCA and Constellation, we make the following clarifications. We clarify that, subject to other conditions discussed below, Category 1 sellers include power marketers and power producers with 500 MW or less of generation capacity owned or controlled by the seller and its affiliates in aggregate per region. Our use of the term ''region'' is intended to be as delineated in the Regional Review and Schedule attached as Appendix D.

860. We further clarify that a seller that owns, operates or controls, or is affiliated with an entity that owns, operates or controls, transmission facilities in the same region as the seller's generation assets does not qualify as a Category 1 seller in that region. This standard applies regardless of whether the total generation capacity owned or controlled by the seller and its affiliates is below 500 MW in the region.

861. Regarding Constellation's point that a company should be considered Category 1 so long as it is not affiliated with a franchised public utility in the same region (and meets the other requirements for Category 1), we concur. Hence, a seller that is affiliated with a franchised public utility that is not in the same region in which the seller owns or controls generation assets may qualify as a Category 1 seller for that region if it meets the other Category 1 criteria. Likewise, a seller that does not own, operate or control, and is not affiliated with an entity that owns, operates or controls, transmission in the same region in which the seller owns or controls generation assets may qualify as a Category 1 seller for that region.

862. We do not adopt Constellation's proposal that we carve out an exemption for sellers affiliated with a franchised public utility without captive customers nor do we adopt the proposal to exempt those that are affiliated with transmission owners that have given operational control of their transmission facilities to RTOs/ISOs.[1007] Constellation has failed to adequately demonstrate that sellers affiliated with a franchised public utility without captive customers and those that are affiliated with transmission owners that have given operational control of their transmission facilities to RTOs/ISOs necessarily lack market power in generation.

863. In addition, we will revise the definition of Category 1 sellers in the regulations to include those that own, operate or control only transmission facilities that are ''limited equipment necessary to connect individual generating facilities to the transmission grid.'' While the NOPR included this language in the preamble, conforming language was inadvertently excluded from the definition of Category 1 sellers in § 35.36(a)(2) of the proposed regulations.

Threshold for Category 1

864. After considering all of the comments regarding the proposed cutoff between Categories 1 and 2, we believe that 500 MW or less of generating capacity per region is an appropriate threshold. We will use this value as a cutoff because, during our 15 years of experience administering the market-based rate program, there have only rarely been allegations that sellers with capacity of 500 MW or less had market power, and when those claims have been raised the Commission's review has either found no evidence of market power or found that the market power identified was adequately mitigated by Commission-enforced market power mitigation rules.[1008] While some commenters urge the Commission to adopt either a higher or lower threshold, the Commission believes that a 500 MW threshold is both a reasonable balance as well as conservative enough to ensure that those unlikely to possess market power will be granted market-based rate authority. Moreover, as Newmont asserts, 500 MW is a clear, bright line that will be easy to administer.

[1002] *Revised Public Utility Filing Requirements,* Order No. 2001, 67 FR 31043 (May 8, 2002), FERC Stats. & Regs. ¶ 31,127 (2002). Required data sets for contractual and transaction information are described in Attachments B and C of Order No. 2001. The EQR must be submitted to the Commission using the EQR Submission System Software, which may be downloaded from the Commission's Web site at *http://www.ferc.gov/docs-filing/eqr.asp.* The exact dates for these reports are prescribed in 18 CFR 35.10b. Failure to file an EQR (without an appropriate request for extension), or failure to report an agreement in an EQR, may result in forfeiture of market-based rate authority, requiring filing of a new application for market-based rate authority if the seller wishes to resume making sales at market-based rates.

[1003] *See Electric Quarterly Reports,* 115 FERC ¶ 61,073 (2006); *Electric Quarterly Reports,* 114 FERC ¶ 61,171 (2006); *Electric Quarterly Reports,* 69 FR 57679 (Sept. 27, 2004); Electric Quarterly Reports, 105 FERC ¶ 61,219 (2003).

[1004] *Duke Power, a Division of Duke Energy Corporation,* 111 FERC ¶ 61,506 at P 48, 55 (2005).

[1005] Order No. 652 at P 47.

[1006] As discussed below in the Change in Status section, the Commission is modifying its regulations to provide that, in the case of power sales contracts with future delivery, such contracts are reportable 30 days after the physical delivery has begun.

[1007] We do, however, replace the term ''public utility with a franchised service territory'' with the defined term ''franchised public utility.''

[1008] Moreover, as noted above, the Commission's indicative screens are set at conservative levels.

865. In addition and in response to commenter requests, we clarify that the 500 MW threshold is determined by adding all the generation capacity owned or controlled by the seller and its affiliates within the same region (as delineated in the Regional Review and Schedule attached as Appendix D). In keeping with our conservative approach with regard to which entities qualify for Category 1, we find that aggregate capacity in a given region best meets our goal of ensuring that we do not create regulatory barriers to small sellers seeking to compete in the market while maintaining an ample degree of monitoring and oversight that such sellers do not obtain market power. In this regard, we also clarify that although we will use aggregate capacity owned or controlled in a region to determine which sellers are required to file regularly scheduled updated market power analyses, we will continue to evaluate the balancing authority area in which the seller is located when performing our indicative screens, absent evidence to the contrary.[1009]

866. While we recognize the appeal of a test that takes into account the size of each geographic market, such as using a percentage of all capacity (as opposed to a stated MW) cutoff and the use of uncommitted capacity rather than installed capacity, these methodologies are inconsistent with a straightforward, conservative means of screening sellers and consequently would lead to regulatory uncertainty. As markets and market participants can fluctuate, a determination of the number of MWs constituting a particular percentage of capacity in a regional market would have to be constantly recalculated and the assumptions underlying a determination could lead to potential challenges. Such an approach would run counter to our intention to provide certainty to market participants and to streamline the administration of the program.

867. The Commission rejects as unnecessary suggestions by AWEA and PPM that we take into account the differences among generation, including that classified as intermittent or non-dispatchable, when calculating the generation capacity of a seller. We believe that many sellers with wind and other non-thermal capacity will fall below the 500 MW threshold; those that do not may take advantage of simplifying assumptions and other means to minimize the burden of filing an updated market power analysis.

868. With respect to several commenters' desire for fact-specific exemptions for sellers who otherwise may qualify for Category 2, we note that the Commission will determine on a case-by-case basis the category status of each seller with market-based rate authorization. In our attempt to keep the Category 1 criteria as simple and straightforward as possible, we may have swept under Category 2 particular sellers whose circumstances make it unlikely that they could ever exercise market power. As a result, we will entertain and evaluate individual requests for exemption from Category 2 and make a finding on the category status of each company. However, if a seller wishes to request exemption from Category 2, it must make a filing seeking such an exemption no later than 120 days before its next updated market power analysis is due. We also will consider any arguments from intervenors that a particular seller that contends that it qualifies for Category 1 status based on our definition should nevertheless be treated as a Category 2 seller and thus be required to continue filing updated market power analyses.

2. Regional Review and Schedule

Commission Proposal

869. To ensure greater consistency in the data used to evaluate Category 2 sellers, the Commission proposed to require ongoing updated market power analyses to be filed for each seller's relevant geographic market on a pre-determined schedule. Such a process would allow examination of the individual seller at the same time that the Commission examines other sellers in the relevant market and contiguous markets within a region from which power could be imported. The Commission appended to the NOPR a proposed schedule for the regional review process, rotating by geographic region with three regions being reviewed per year. For corporate families that own or control generation in multiple control areas and different regions, the Commission proposed that the corporate family would be required to file an update for each region in which members of the corporate family sell power during the time period specified for that region.

Comments

870. Several commenters, including ELCON, APPA/TAPS, NRECA, Suez/Chevron, and Newmont, support the Commission's proposal. ELCON states that the requirement that a seller file its updated market power analysis at the same time the Commission examines other sellers in the relevant market and region is an excellent idea because it provides a better picture to the Commission during its review. APPA/TAPS state that the regional approach will lead to data consistency and availability, and will allow the Commission to fulfill its obligations more completely. Newmont believes that the Commission's proposal appropriately balances the need to effectively monitor and mitigate market power while avoiding unnecessary and unproductive regulatory requirements.[1010]

871. Alternatively some commenters oppose the proposal entirely, or suggest modifications. Reliant states that the regional review and schedule would significantly increase the administrative burdens of compliance rather than streamline them. According to Reliant, companies that engage in business in multiple regions of the United States would have to file several times over the three year schedule instead of once as is required currently.[1011] Morgan Stanley and Financial Companies state that the Commission should require Category 2 sellers to file only once every three years, either with the region where they have a franchised service territory or the region in which they own the greatest amount of generation. EEI and EPSA maintain that a regional review will pose a great burden on utilities operating in multiple markets and will lead to confusion over contradictory information.[1012]

872. State AGs and Advocates warn that the regional approach will result in a too infrequent analysis of each area. They and others state that, with the combined approach, each specific region will only be looked at completely every three years, which is less oversight than the Commission has currently.[1013]

873. FirstEnergy notes that the Commission has encouraged PJM and Midwest ISO to eliminate ''seams'' between their respective regions and comments that the proposal to schedule submittal of updated market power analyses for sellers in these two regions

[1009] As we have stated above, where a generator is interconnecting to a non-affiliate owned or controlled transmission system, there is only one relevant market (*i.e.*, the balancing authority area in which the generator is located).

[1010] Newmont at 1.

[1011] Similarly, Allegheny, Mirant, FP&L, EEI, FirstEnergy, MidAmerican, TXU, Morgan Stanley, Financial Companies, and EPSA argue that large corporate families could find themselves in a perpetual triennial review that would place a substantial regulatory burden and expense on them.

[1012] EEI reply comments at 27–29, EPSA reply comments at 11–14.

[1013] *See, e.g.*, State AGs and Advocates at 49–51, Reliant at 9–11, Mirant at 2–6, EPSA at 39–40, EEI reply comments at 27–29, EPSA reply comments at 11–14.

at different times is inconsistent with the reasons underlying adoption of common filing dates. Mirant states that the limited number of consultants that perform market power analyses use separate, proprietary databases and warns that the market data submitted on a regional basis will remain inconsistent. Further, Mirant asserts that there may be antitrust issues if a group of competing sellers jointly hires one consultant.

874. NRECA replies that any increase in the burden on sellers does not outweigh the substantial benefits of greater data consistency and a complete picture of each region under review.[1014] APPA/TAPS assert that the Commission should not sacrifice improvements to its program for the interests of a few companies and that any increased cost to companies associated with regional reviews is outweighed by the companies' profits from market-based rate sales. They dismiss concerns regarding a scarcity of consultants, noting that the market should respond to an increase in demand for consulting services, and that ''competition will force efficiency gains to be passed along to consultants'' clients.''[1015] Further, with respect to a group of sellers jointly hiring a consultant to produce a market analysis, they comment that antitrust counsel should be able to ensure joint representation does not result in improper information sharing.[1016]

875. PNM/Tucson state that the updated market power analyses in a given region should be deliberately staggered so that utilities are able to build upon data sets already submitted in prior proceedings, instead of each having to construct its own, which would result in varying, competing data sets.

876. Mirant and FP&L add that with all the entities filing concurrently it will be difficult for some, such as non-transmission owning entities, to acquire the necessary data (*i.e.*, simultaneous import limit data). NRECA, Mirant and Powerex ask the Commission to have transmission-owning utilities file their updated market power analyses (or information necessary for others to perform preliminary screens) at a minimum 90 days prior to the regional due date; MidAmerican requests that the Commission require each transmission provider to post to its OASIS a simultaneous import study 60 days before the filing deadline that could be used by first-tier entities to develop their market power analyses.

[1014] NRECA reply comments at 28–30.

[1015] APPA/TAPS reply comments at 20.

[1016] *Id.* at 19–21.

Similarly, Suez/Chevron suggests requiring RTOs and/or control area operators in each region to file certain information in advance of the filing deadline so that sellers can rely on uniform baseline data.[1017] EEI critiques the proposals for sharing of data prior to submission of triennial reviews, stating that this would increase the complexity of an already cumbersome process.[1018]

877. APPA/TAPS state that data sharing by companies should be enhanced by regional reviews, not impaired, and that more robust data and opportunities to reconcile conflicting submissions with a regional review will lead to a better analysis by the Commission.[1019]

878. MidAmerican asserts that the Commission should allow more time between the end of the qualification period and the filing of market power analyses. It states that these analyses require Form 1 data that is not available until several months after the end of the calendar year and that control area loads as filed in Form 714 are frequently not available until the third quarter following the end of the calendar year, usually July. Additionally, it states that generation and load data from Forms EIA–860 and EIA–861, respectively, are likewise not available until late in the following year. Accordingly, it suggests that market analyses should not be due until mid-October following the end of the qualification period, allowing roughly 90 days between the availability of Form 714 and the deadline for filing.[1020]

879. Many commenters also argue that the Commission should extend the time until the first regional reviews are due. Suggested beginning filing dates include: the first filing period for a region that is no earlier than a company's next required updated analysis;[1021] the first filing period that occurs no earlier than two years from the latest filed updated analysis;[1022] the first filing period that is no earlier than one year from the latest filed updated analysis;[1023] or 180 days after the Final Rule is published in the **Federal Register**.[1024] Duke suggests that, rather than extending the first filing times, the

[1017] The data Suez/Chevron refer to include the information indicated in proposed Appendix C, Pivotal Supplier Analysis at Rows E through J, O, P and Q and also proposed Appendix C, Wholesale Market Share Analysis at Rows F through Q, and the accompanying workpapers.

[1018] EEI reply comments at 27–29.

[1019] APPA/TAPS reply comments at 19–21.

[1020] *See* MidAmerican at 33.

[1021] *See* Consumers at 2–4, Allegheny at 16–18.

[1022] *See* MidAmerican at 30–33.

[1023] *See* Constellation at 13.

[1024] *See* Allegheny at 16–18.

Commission clarify that those entities due to file their next updates before the scheduled regional reviews are due can forgo making any interim filings.

880. APPA/TAPS ask the Commission to extend the period for commenting on the updated market power analyses from the current 21-day comment period to 60 days, at a minimum. They state that because numerous sellers will file the updated market power analyses contemporaneously, intervenors should be given sufficient time to make meaningful use of the expanded body of information and to prepare multiple pleadings dealing with various sellers in the region. They add that the additional time should improve the quality of the analyses that the Commission receives from intervenors.

881. Finally, regarding the Commission's proposal to require all updates (and all new applications) to include an appendix listing all generation assets owned or controlled by the corporate family, in-service dates and capacity ratings by unit, Duke agrees with the proposal that the appendix should also reflect all electric transmission and natural gas intrastate pipelines and/or gas storage facilities owned or controlled by the corporate family. It states that having such a standardized listing will be helpful both to the Commission and to other market participants.[1025] Duke cautions, however, that including the location of transmission and gas pipeline facilities in the appendix could conflict with CEII requirements, and requests clarification that sellers will have discretion with locational descriptions.

Commission Determination

882. The Commission adopts the NOPR proposal to conduct a regional review of updated market power analyses, with certain modifications. We agree with commenters such as APPA/TAPS that the regional approach will lead to data consistency and availability. In this regard, both the Commission and market participants will benefit from greater data consistency that will result from regional examination of updated market power analyses and a methodical study of all sellers in the same region. This will give the Commission a more complete view of market forces in each region and the opportunity to reconcile conflicting submissions, enhancing our ability to ensure that sellers' rates remain just and reasonable.

883. Although some commenters express concern that a regional review approach will increase administrative

[1025] Duke at 49.

burdens, particularly for sellers operating in multiple regions, we believe that the Commission's proposal properly and fairly balances the need to effectively monitor and mitigate market power in wholesale markets with the desire to minimize any administrative burden associated with the filing and review of updated market power analyses. While we recognize that some sellers may have to file updates more frequently than they do currently, we have carefully balanced the interests of all involved, and we believe that regional reviews of updated market analyses is both needed and desirable and will enhance the Commission's ability to continue to ensure that sellers either lack market power or have adequately mitigated such market power.

884. We note that sellers currently must prepare a market power analysis for all of their generation assets nationwide. Some sellers with assets in multiple regions have chosen to submit their individual updated market power analyses when each is due (every three years) rather than combining them into a single updated market power analysis. Others file one updated market power analysis for the entire corporate family, with individual analyses of the different markets in which their assets are located. Either way, the same analyses must be filed under the status quo and the approach adopted in this Final Rule. The timing may differ, but the increased burden is minimal.[1026]

885. Nevertheless, considering the comments received and upon further review of the Commission's proposal, we believe that some of the proposed regions should be consolidated. Therefore, we will reduce the number of regions from the proposed nine to six. In Appendix D we identify the six regions (Northeast, Southeast, Central, Southwest Power Pool, Southwest, and Northwest), and will require Category 2 sellers that own or control generation assets in each region to file an updated market power analysis for that region every three years based on a rotating schedule shown in the Appendix.[1027] We believe that, with fewer and larger regions, some sellers will likely be present in fewer regions and administrative burdens for those sellers accordingly will be reduced. In addition, the decrease in the number of regions will also extend the time period between filings. In the NOPR, the Commission stated that three regions would be reviewed per year, with four months between each set of filings. Here we adopt review of two regions per year, with the filing periods six months apart.

886. Regarding FirstEnergy's argument that PJM and Midwest ISO should be placed in the same region, we continue to encourage PJM and the Midwest ISO to address ''seams'' issues. However, we find that placing them in different regions for the purpose of determining when an updated market power analysis is submitted should in no way affect or discourage efforts to address seams between these two regions. Other considerations (such as balancing RTO/ISO and non-RTO/ISO filings, and scheduling approximately the same number of filings each year) outweigh FirstEnergy's concerns.

887. The Commission rejects the arguments by some commenters that the regional approach will result in too infrequent an analysis of each area. As a practical matter, currently sellers are required to file an updated market power analysis every three years. In the intervening years between updated market power analyses, most utilities either enjoy the 18 CFR 35.27(a) exemption from filing a generation market power analysis or rely on the previously filed updated market power analysis. The regional approach will provide the Commission with a snapshot of sellers across a larger area and will provide a more accurate view of simultaneous import capability into the relevant geographic markets under review. Accordingly, contrary to claims that the regional approach will result in less Commission oversight, the regional approach will enhance the Commission's ability to analyze market power using better data with less opportunity for conflicting claims of ownership or control of generation assets.

888. Regarding concerns about the scarcity of consulting firms, we note that our proposal will not necessarily increase the number of market power analyses to be performed (indeed, by exempting all Category 1 sellers from submitting updated market power analyses, the number may be decreased). We agree with APPA/TAPS that any shortage of consultants performing market power analyses should be temporary as firms adjust to a new schedule reflecting the regional review timetable and take precautions to prevent improper information sharing.

889. We agree with commenters that transmission-owning entities should file their updated market power analyses in advance of others in each region. Thus, the Commission will modify the schedule proposed in the NOPR to better allow sellers to rely on the transmission-owning utilities' information, and we will adopt a staggered filing approach for each region which will require different types of entities to file at different times. The transmission-owning utilities, which have the information necessary to perform SIL studies, will be required to file their updated market power analyses first. Six months later, all others in that region will be required to file their updated market power analyses.[1028]

890. Staggering the time periods within which transmission-owning and non-transmission-owning utilities will be required to submit their updated market power analyses will provide an opportunity for those non-transmission owning sellers that need simultaneous transmission import limits to perform the screens to rely on the SIL studies performed by the transmission-owning utilities rather than rely on a ''proxy'' for the import limits.

891. Our experience is that sellers located in RTOs/ISOs typically do not need to rely on a SIL study in performing the screens, and transmission-owning utilities in RTOs/ISOs typically do not prepare or submit such studies. Accordingly, staggered filings for sellers in RTOs/ISOs may not be necessary for purposes of data availability. Nevertheless, we will retain the staggered filing deadlines for all regions for consistency and to avoid any confusion in this regard. If a particular seller that is located in an RTO/ISO finds that it needs import data in order to complete its market power analysis, we expect the RTO/ISO to assist such sellers if requested.

892. In response to MidAmerican's suggestion that the Commission allow adequate time between the date that all data is available and the date that a region's analyses are due, we will schedule the updates to be filed in December (12 months after the study year), and June (18 months after the study year). We note that studies due in

[1026] In this regard, we note that preparation of multiple market power analyses is likely less burdensome and less expensive than what would otherwise be required under cost-based regulation which can result in extended administrative litigation to determine the just and reasonable rate.

[1027] Concerning power marketers that may not own or control generation assets in any region, we will require the submission of a filing explaining why the seller meets the Category 1 criteria, as discussed above. Power marketers must submit such a filing with the first scheduled geographic region in which they make any sales.

[1028] If the Commission has not processed a particular SIL study before six months have passed and non-transmission owning entities must file their updated market power analyses, then those entities should rely on the filed SIL study. If the initial SIL study subsequently changes, the Commission will make conforming adjustments as needed.

December and June may be filed anytime during the applicable month. Such a schedule will allow adequate time for the data to be available (at least 6 weeks after EIA Forms 860 and 861 become public) and the analyses to be completed.

893. In response to commenters' requests that the Commission extend the time until the first analyses are due, we will commence the schedule in December 2007. The Commission believes this will provide adequate notice and time to prepare the analyses. In addition, we clarify that sellers that otherwise would have been required to file an updated market power analysis before the effective date of this rule should submit their updated market power analyses in accordance with past orders directing them to do so. Starting with the effective date of this rule, sellers should submit their updated market power analyses in accordance with the schedule set forth in Appendix D.

894. We also agree with the suggestion of APPA/TAPS to extend the period for intervenors to comment on the updates. We agree that extending the comment period will allow intervenors a better opportunity to review and comment on filings, especially considering the large number of filings that will be submitted at one time. For that reason, the Commission will establish a 60-day comment period for updated market power analyses. Further, we adopt the NOPR proposal to require that with each new application and updated market power analysis, the seller must list in an appendix, among other things, all affiliates that have market-based rate authority and identify any generation assets owned or controlled by the seller and any such affiliate. In addition, we extend this obligation to relevant change in status notifications.[1029] We believe that requiring the submission of such data will provide the Commission with more accurate and up-to-date information about each corporate family and will address some of our concerns regarding confusion that has occurred with respect to corporate families and, in particular, what sellers are authorized to transact at market-based rates in each corporate family.

895. Accordingly, the appendix must list all generation assets owned (clearly identifying which affiliate owns which asset) or controlled (clearly identifying which affiliate controls which asset) by the corporate family by balancing authority area, and by geographic region, and provide the in-service date and nameplate and/or seasonal ratings by unit. As a general rule, any generation assets included in a seller's or a seller's affiliate's market study should be listed in the asset appendix. We find that the in-service date and nameplate and/or seasonal ratings help identify and provide the Commission and market participants with critical market information. In addition, the appendix must reflect all electric transmission and natural gas intrastate pipelines and/or gas storage facilities owned or controlled by the corporate family and the location of such facilities.

896. In response to Duke, we clarify that CEII data is more detailed than ''simply [giving] the general location of the critical infrastructure.'' [1030] As the location of the facilities listed in the appendix need only include the balancing authority area and geographic region (see sample appendix attached as Appendix B) in which they are located, we do not anticipate that any CEII will be disclosed.

### *F. MBR Tariff*

Commission Proposal

897. In the NOPR, the Commission proposed to adopt a market-based rate tariff of general applicability (MBR tariff), applicable to all sellers authorized to sell electric energy, capacity or ancillary services at wholesale at market-based rates, as a condition of market-based rate authority. The MBR tariff, as proposed, would require each seller to comply with the applicable provisions of the market-based rate regulations to be codified at 18 CFR Part 35, Subpart H. The Commission proposed that each seller would be required to list on the MBR tariff the docket numbers and case citations, where applicable, of any proceedings where the seller received authorization to make sales of energy between affiliates or where its market-based rate authority was otherwise restricted or limited.

898. The Commission explained that not all of the provisions of the proposed regulations may be applicable to all sellers. For example, a seller may not wish to offer ancillary services under the tariff. The Commission sought comments regarding whether a placeholder should be reserved in the MBR tariff for the seller to indicate those parts of the regulations that are not applicable to it.

899. The Commission stated that this streamlining effort is not intended to reduce the flexibility of sellers and customers in negotiating the terms of individual transactions. The Commission noted that sellers would continue to negotiate the terms and conditions of sales entered into under their MBR tariff, and the terms and conditions of those underlying agreements and the transaction data would be reflected in the quarterly EQRs. The Commission stated that if sellers wish to offer or require certain ''generic'' terms and conditions that in the past were contained in their market-based rate tariff, they may place customers on notice of such requirements by including such information on a company Web site and include any related provisions in individual transaction agreements. The Commission explained its desire that the MBR tariff reflect, in a consistent manner, only those matters that are required to be on file.[1031]

900. Further, rather than each entity having its own MBR tariff, which can result in dozens of tariffs for each corporate family with potentially conflicting provisions, the Commission proposed that each corporate family have only one tariff, with all affiliates with market-based rate authority separately identified in the tariff.[1032] The Commission stated that this would reduce the administrative burden and confusion that occurs when there are multiple, and potentially conflicting, tariffs in a single corporate family, and would allow the Commission and customers to know what sellers are in each corporate family.

1. Tariff of General Applicability

Comments

901. Several commenters do not support the adoption of a tariff of general applicability. Allegheny argues that ''the Commission is without legal authority to impose a one-size-fits-all market-based rate tariff.'' [1033] It argues that the Commission has made no finding of undue discrimination and is not proposing to act under FPA section 206, and asserts that administrative efficiency is an insufficient justification to impose a standardized tariff on market-based rate sellers. Similarly, FirstEnergy asserts that requiring a uniform MBR tariff would impose undue administrative burdens on sellers, as each would have to make a compliance filing modifying its currently effective tariff and would also

[1029] Relevant change in status notifications would include, for example, the addition of new facilities, but not a name change.

[1030] 18 CFR 388.113(c)(1)(iv).

[1031] NOPR at P 163.

[1032] *Id.* at P 164.

[1033] Allegheny at 20.

have to expand its compliance program to confirm that its tariff was in conformance with the uniform tariff.

902. Xcel states that the Commission has not made clear its basis for and expected benefit from a *pro forma* tariff. Xcel suggests that, if it is adopted, then the Commission should describe any limitations on a seller's market-based rate authority, in addition to identifying any docket numbers where they were imposed.[1034]

903. Similarly, Avista Corporation believes that all of the terms and conditions of a tariff should be included in one easily accessible place. Requiring that certain terms and conditions be posted on a company Web site, rather than the tariff, is bound to cause unnecessary confusion as to which terms and conditions apply, and will increase the burden on both the utilities to notify, and customers to remain apprised, of when those terms and conditions change.[1035] Additionally, FirstEnergy states that a process by which a seller places customers on notice of such terms and conditions beyond the minimum by including such information on a company Web site, and including related provisions in individual transaction agreements, would be cumbersome at best, and would deprive sellers and customers of the benefit of having the ''generic'' terms and conditions in one document.[1036]

904. Commenters who responded to the question of whether a placeholder should be reserved in the tariff to indicate parts of the regulations that are not applicable to the seller, support the idea of a placeholder.[1037]

905. Mirant notes that the sample MBR tariff attached to the NOPR did not provide for specific RTO/ISO ancillary service products and states that it is unclear how the Commission would identify which seller under the corporate tariff is permitted to sell the specific ancillary services traded in each region. Mirant asks whether the Commission would require each seller of ancillary services to maintain an ancillary services tariff on file with the Commission. Mirant further notes that some sellers not located in an RTO/ISO have been granted authorization to sell ancillary services at market-based rates if they post those services on their Web sites and suggests that the requirement that sellers maintain such a Web site would have to be cross-referenced in the corporate tariff.

906. EEI states that companies with operations in multiple markets may need to tailor their market-based rate tariffs to reflect the particular circumstances of each market. This will be true for RTO and ISO markets as well as non-RTO markets. In each of these cases, participants in the markets typically must agree to abide by specific market terms and conditions that may need to be reflected in the tariff. Therefore, EEI encourages the Commission to allow each company to file multiple tariffs, as may be necessary to reflect these market differences.[1038]

907. Regarding the timing of tariff implementation, MidAmerican comments that the Commission should apply the new tariff prospectively only to future transactions, and urges that existing tariffs should be unaffected until existing transactions expire. MidAmerican observes that if existing tariffs containing terms and conditions are replaced by the proposed generic tariff, then neither the new tariff nor the existing service agreements will reflect the terms and conditions of ongoing transactions.

908. ELCON supports the proposed MBR tariff, believing that it will be more customer-friendly. APPA/TAPS agree, stating that a pro forma tariff will help by addressing variations in MBR tariffs that increase transaction costs by creating potential confusion about applicable terms and conditions.[1039] A number of commenters find some merit in the concept of the MBR tariff, but request clarifications or revisions.[1040] Some of these entities comment that companies with operations in multiple markets may need to tailor their tariffs to reflect the particular circumstances of each market, and state that participants in organized markets typically must agree to abide by specific terms that may need to be reflected in their tariffs.

909. Indianapolis P&L asserts that any restrictions on market-based rate authority should be in a tariff, rather than in Commission orders. It believes that ''converting concepts (*e.g.*, all sales in a control area will be mitigated) into precise contract-worthy terms and conditions can be very difficult'' and argues that the best way to prevent misunderstandings between parties is to have ''precise, transparent and, publicly-available language in a tariff explaining the precise conditions on an entity's market-based rate authority.'' [1041] Indianapolis P&L further warns that ''having restrictions on an entity's market-based rate authorization contained in a tariff only through cross-reference to a Commission order may run afoul of the FPA requirement that rates be 'on file' with the Commission.'' [1042]

910. Constellation seeks clarification that a seller that has received waiver from the code of conduct need not report in its MBR tariff that the affiliate restrictions in proposed § 35.39 do not apply to it. Alternatively, Constellation suggests that the Commission allow sellers to list the appropriate docket numbers in which the Commission has granted waivers of the code of conduct or provide a place to indicate that the provisions are not applicable. Constellation notes that many market-based rate sellers have included provisions in their tariffs regarding reassignment of transmission capacity and sale of firm transmission rights, congestion contracts, or fixed transmission rights (as a group, ''FTRs''), and requests that the Commission either provide for inclusion of such provisions in the MBR tariff or state affirmatively that they will not be required.

Commission Determination

911. In the NOPR, the Commission explained that it was acting pursuant to sections 205 and 206 of the FPA in proposing to amend its regulations to govern market-based rate authorizations for wholesale sales of electric energy, capacity and ancillary services by public utilities, ''including modifying all existing market-based rate authorizations and tariffs so they will be expressly conditioned on or revised to reflect certain new requirements proposed herein.'' [1043] Section 205 of the FPA requires that all rates for sales subject to our jurisdiction, and all rules and regulations pertaining to such rates, be just and reasonable. Section 206 of the FPA provides that, when the Commission finds that a rate or a rule, regulation or practice affecting a rate, is unjust or unreasonable, the Commission shall determine the just and reasonable rate, rule or regulation and order it so.

912. Based on careful consideration of the comments received, the Commission agrees that complete uniformity of market-based rate tariffs is not necessary. However, pursuant to our

[1034] Xcel at 17.

[1035] Avista at 10–12.

[1036] First Energy at 27–31.

[1037] Avista at 10; MidAmerican at 33 (suggesting that the placeholder could be included as an attachment to each seller's tariff in order to preserve the generic nature of the tariff itself); Progress Energy at 19.

[1038] EEI at 49.

[1039] EEI counters APPA/TAPS, asserting that each seller's MBR tariff in a given market is fully available to market participants, so there should be no confusion. EEI reply comments at 30–31.

[1040] FirstEnergy at 27–29; Constellation at 27–29; Progress Energy at 19–23.

[1041] Indianapolis P&L at 15.

[1042] *Id.*

[1043] NOPR at P 1.

authority under sections 205 and 206, we conclude that the lack of consistent tariff form and content has hampered our ability to manage the market-based rate program in an efficient manner and has introduced uncertainty for potential customers. We find that continuing to allow basic inconsistencies in the market-based rate tariffs on file with the Commission is unjust and unreasonable. Nevertheless, we find that we can achieve our goal without imposing a uniform tariff requirement on all sellers by, instead, requiring that all sellers revise their market-based rate tariffs to contain certain standard provisions, as discussed below.

913. We believe the approach we adopt here addresses the concerns of commenters that the Commission not impose a one-size-fits-all approach while, at the same time, presenting a uniform set of required provisions that will provide adequate certainty and will be more customer friendly. In addition, we believe that allowing sellers to include seller specific terms and conditions in their market-based rate tariffs will offer a greater degree of transparency and serve customers by providing for the opportunity to have all terms and conditions identified and in one place. As Progress Energy asserts, ''[g]reater consistency of tariffs within the industry * * * will not only reduce customer confusion, it also will reduce the administrative burden of those responsible for the implementation and administration of the tariff.'' [1044]

914. Accordingly, in this Final Rule, we adopt two standard ''required'' provisions that each seller must include in its market-based rate tariff: a provision requiring compliance with the Commission's regulations and a provision identifying any limitations and exemptions regarding the seller's market-based rate authority.

915. In particular, with regard to compliance with the Commission's regulations, we will require each seller to include the following provision in its market-based rate tariff:

Seller shall comply with the provisions of 18 CFR Part 35, Subpart H, as applicable, and with any conditions the Commission imposes in its orders concerning seller's market-based rate authority, including orders in which the Commission authorizes seller to engage in affiliate sales under this tariff or otherwise restricts or limits the seller's market-based rate authority. Failure to comply with the applicable provisions of 18 CFR Part 35, Subpart H, and with any orders of the Commission concerning seller's market-based rate authority, will constitute a violation of this tariff.

[1044] Progress Energy at 19–20.

916. We also will require that the seller include a provision identifying all limitations on its market-based rate authority (including markets where the seller does not have market-based rate authority) and any exemptions from, or waivers of, or blanket authorizations under the Commission's regulations that the seller has been granted (such as exemption from affiliate sales restrictions; waiver of the accounting regulations; blanket authority under Part 34 for the issuances of securities and liabilities, etc.), including cites to the relevant Commission orders.

917. In addition to the required tariff provisions, we also will adopt a set of standard provisions (which we reference herein as ''applicable provisions'') that must be included in a seller's market-based rate tariff to the extent that they are applicable based on the services provided by the seller. For example, if the seller's sales under its market-based rate tariff are subject to mitigation, it must include the standard provision governing mitigated sales. Similarly, if the seller makes sales of certain ancillary services in certain RTOs/ISOs, or if it makes sales of ancillary services as a third-party provider, it must include the standard ancillary services provisions, as applicable.

918. Attached hereto as Appendix C is a listing of the standard required provisions and the standard applicable provisions. The Commission will post these provisions on its web site and will update them as appropriate.

919. In addition, as discussed more fully below, we will permit sellers to list in their market-based rate tariffs additional seller-specific terms and conditions that go beyond the standard provisions set forth in Appendix C.

920. As Constellation observes, the uniform MBR tariff proposed in the NOPR did not provide for sellers to offer reassignment of transmission capacity or FTRs. As revised in this Final Rule, Appendix C does not contain a standard provision for the reassignment of transmission capacity. The Commission believes that, although these items have historically been offered in the context of sales of electric energy and capacity, they are transmission-related rather than generation services. Accordingly, the Commission has made provision for reassignment of transmission capacity in the revised OATT, as discussed in Order No. 890.[1045] Thus, we state affirmatively here that provisions concerning the reassignment or sale of transmission capacity or FTRs are not required to be included in a seller's market-based rate tariff, nor is it appropriate to include transmission-related services in the seller's market-based rate tariff. Sellers seeking to reassign transmission capacity should adhere to the provisions of Order No. 890 [1046] and should revise their market-based rate tariffs to remove provisions governing these services at the time they otherwise revise their tariffs to conform them to the standard provisions discussed herein.

[1045] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 814–816 & n.496.

921. Regarding FTRs and, incidentally, virtual trading,[1047] we note that Commission-approved market rules for RTOs/ISOs address resales of FTRs and virtual trading to ensure that no market power is exercised in such trades. In addition, sellers engaging in these activities sign a participation agreement with RTOs/ISOs which require them to abide by those market rules. Hence, the approval of the market rules in conjunction with approval of the generic participation agreement by the Commission constitutes authorization for public utilities to engage in the resale of FTRs and virtual transactions, and no separate authorization is required under the FPA. The Commission's monitoring of the effectiveness of the market rules and oversight of participants engaging in FTR resales and virtual trading in the RTO/ISO markets provide sufficient protections against the exercise of market power. Nevertheless, if the Commission concludes in the future that a separate section 205 authorization would better enable us to ensure that FTR resales or virtual trading do not result in unjust and unreasonable

[1046] *Id.* at P 816.

[1047] Virtual trading involves sales or purchases in an RTO/ISO day-ahead market that do not go to physical delivery. For example, virtual bidding allows entities that do not serve load to make purchases in the day-ahead market. Such purchases are subsequently sold in the real-time spot market. Likewise, entities without physical generating assets can make power sales in the day-ahead market that are subsequently purchased in the real-time market. By making virtual energy sales or purchases in the day-ahead market and settling these positions in the real-time, any market participant can arbitrage price differences between the two markets. For example, a participant can make virtual purchases in the day-ahead if the prices are lower than it expects in the real-time market, and then sell the purchased energy back into the real-time market. The result of this transaction would be to raise the day-ahead price slightly due to additional demand and, thus, improve the convergence of the day-ahead and real-time energy prices due to additional supply in the real-time. Virtual trading is not limited to entities without assets. For example, generators or loads that prefer to transact at the real-time price may use virtual trading to accomplish this without having to under-schedule load or withhold generation from the day-ahead market by submitting matching virtual trades.

wholesale rates, the Commission may change the filing requirements for engaging in these activities.[1048]

922. To the extent that individual companies within a corporate family need or desire a tariff separate from their affiliates, the Commission will allow this, as discussed below. Although EEI asserts that participants in organized markets may need to meet the requirements of various organized markets, EEI offers no specific examples in this regard. Nevertheless, we believe that our action to replace the uniform MBR tariff proposed in the NOPR with standard provisions that we will require to be included in a seller's market-based rate tariff and the allowance of seller specific terms and conditions in the market-based rate tariff should meet the needs of all sellers with market-based rate authority.

923. We will require all market-based rate sellers to make section 206 compliance filings to modify their existing tariffs to include the standard required provisions set forth in Appendix C as well as any of the standard applicable provisions. These compliance filings are to be made by each seller the next time the seller proposes a tariff change, makes a change in status filing, or submits an updated market power analysis (or a demonstration that Category 1 status is appropriate) in accordance with the schedule in Appendix D.

924. One of the required standard provisions (the compliance with Commission regulations provision) states that failure to comply with the applicable provisions of the regulations adopted in this Final Rule or with any Commission orders concerning a seller's market-based rate authority will constitute a violation of the seller's tariff. As provided in this Final Rule, the regulations at 18 CFR Part 35, Subpart H will become effective 60 days after publication of this Final Rule in the **Federal Register**. Accordingly, this provision will be considered part of each seller's market-based rate tariff effective as of the effective date of this Final Rule. As noted above, all sellers will be required to amend their market-based rate tariffs to include the required standard provisions, as well as the required applicable provisions, either at the time that they file any other amendment to their current tariffs, when they report a change in status, or when they file their updated market power analysis, whichever occurs first. However, regardless of the date on which sellers make their compliance filing, the provision providing that failure to abide by the regulations will constitute a tariff violation will be considered part of each seller's current market-based rate tariff as of 60 days after the date of publication of this Final Rule in the **Federal Register**.

2. Placement of Terms and Conditions

Comments

925. In the NOPR, the Commission observed that the purpose of an MBR tariff of general applicability is not to direct the terms and conditions of particular sales but to ensure that the tariff on file reflects in a consistent manner only those matters that are required to be on file, namely, the identity of the seller(s), the docket number(s) of the market-based rate authorization, the seller's requirement to follow the conditions of market-based rate authorization contained in the proposed regulations, and that the rates, terms and conditions of any particular sale will be negotiated between the seller and individual purchasers. The Commission stated that sellers could offer other ''generic'' terms and conditions as information on a company Web site.

926. In response, several commenters state that requiring companies to move generic terms and conditions to a company Web site, or to replicate them in individual agreements or rely on Commission orders, would be confusing and/or overly cumbersome.[1049] Avista and FirstEnergy believe that all of the terms and conditions of a tariff should be in one easily accessible place; otherwise, sellers and customers would be deprived of the benefit of having them in one document. According to FirstEnergy, this ''would be contrary to the goal of establishing a 'customer-friendly tariff' as contemplated in the NOPR.'' [1050] Further, FirstEnergy states that the fact that the Commission may not review individualized commercial terms included in tariffs does not make it unjust and unreasonable for sellers to include such terms in their tariffs; thus, there is no basis for the Commission to exercise its authority under FPA § 206 to require changes to existing market-based rate tariffs. However, Progress Energy agrees with the Commission that commercial terms and conditions for sales under the MBR tariff should not be filed for Commission review.

Commission Determination

927. As discussed above, we find consistency of standard market-based rate tariff provisions to be essential, and we modify the proposal in the NOPR by adopting a set of standard tariff provisions that we will require each seller to include in its market-based rate tariff, but we do not adopt the NOPR proposal that all sellers adopt the uniform MBR tariff of general applicability set forth in the NOPR. After careful consideration of the comments, we also will not adopt the NOPR proposal that sellers offer other generic terms and conditions as information on a company Web site. We agree with commenters as to the benefits to sellers and customers of having all terms and conditions relevant to a seller's market-based rate power sales available in one document. Thus, we will permit sellers to list in their market-based rate tariffs additional terms and conditions that go beyond the standard provisions required in Appendix C (with the exception of transmission-related services, as discussed above), as modified in this Final Rule. As has been our practice in many instances, we will not evaluate the justness and reasonableness of such additional provisions, but will allow them to be included in the market-based rate tariff that is on file with the Commission. Our reasoning is that such additional provisions are presumptively just and reasonable. A seller granted market-based rate authority has been found not to have, or to have adequately mitigated, market power; thus, if a customer is not satisfied with the terms and conditions offered by a seller, the customer can choose to purchase from a different supplier.

3. Single Corporate Tariff

Comments

928. ELCON supports the NOPR proposal that each corporate family have one tariff on file, stating that it will lead to better transparency regarding what each seller in a corporate family owns or controls. APPA/TAPS agree, commenting that a single corporate tariff addresses recurring problems with determining exactly who is affiliated with whom.[1051] Sempra agrees in

[1048] To the extent that this position departs from our holding in *California Independent System Operator, Inc.*, 89 FERC ¶ 61,153 at 61,435–36 (1999) (requiring, among other things, that all public utility resellers of FTRs file a rate schedule for authorization to make resales) we note that that analysis rested on Order No. 888's filing requirements for resales of transmission capacity. As Order No. 890 has modified the filing requirements with respect to reassignments of transmission capacity (in addition to the reasons cited above) we find it appropriate not to require a separate rate schedule for FTRs or virtual trading at this time.

[1049] Avista at 10–12; Indianapolis P&L at 14–15; FirstEnergy at 27–31.

[1050] FirstEnergy at 29.

[1051] EEI disagrees, contending that, since companies already disclose affiliations in their

Continued

general that the single tariff structure should eliminate confusion that results when entities within the same corporate family have tariffs with terms that differ.

929. However, a number of commenters raise potential implementation issues and believe that having all entities in a corporate family selling under the same tariff should be optional and not mandatory.[1052] Several of these commenters state that the Commission has not demonstrated the need for a single corporate tariff and believe that the added burden of implementation would outweigh any benefits.[1053]

930. Some of the problems with the single corporate tariff proposal identified by commenters include the following:

- The proposal does not make sense for diversified energy companies with a variety of non-utility generator or power marketer affiliates because it would require increased regulatory and legal coordination among affiliates;
- The burden of replacing multiple market-based rate tariffs with one umbrella tariff would be significant, requiring amendment and re-execution of many documents with many trading counterparties, as well as extensive changes to the existing quarterly reporting process;
- A single tariff listing all affiliates could create confusion regarding which affiliates may be bound by certain executed service agreements, or which terms and conditions apply to certain affiliates;
- Confusion would result when trying to create a single tariff per corporate family when sellers can have multiple corporate families; listing the same seller on the MBR tariffs of multiple corporate groups would not improve transparency; and
- Given that some sellers' upstream ownership can include multiple investors, passive investors, and limited partners, the proposal could impose a filing requirement on entities that have only a passive role and may not otherwise be engaged in the energy business.

931. Several commenters assert that, while they support the objective of simplifying tariff administration, the Commission has not considered the administrative and commercial ramifications of mandating one tariff per family. For instance, Duke cites the possibility that any seller under the corporate tariff could be sued for an affiliate's alleged breach, and the complications of Company A selling Subsidiary X to Company B and the status of X's sales under Company A's tariff. Mirant questions how the sale of a subsidiary's MBR tariff to a non-affiliate would be handled, given that the tariffs are assets that can be bought and sold. In a related comment, Ameren asks for which company or companies would the tariff be a jurisdictional facility for purposes of FPA section 203. EPSA and Sempra request clarification regarding how an enforcement action would be affected by the presence of other members of a corporate family on the same tariff, and Ameren seeks clarification on the effect of a revocation of market-based rate authority of only some companies in a corporate family. MidAmerican suggests that, since different affiliates within a corporate family may have authority to offer different services, a service schedule to the tariff should specify the products that each affiliate is authorized to offer and any restrictions or limitations on a seller's market-based rate authorization. Morgan Stanley notes that, in many cases, the ''parent'' is not a jurisdictional entity or is a holding company, and recommends requiring each corporate family to designate a lead company that will submit its filing and those of its affiliates, rather than specifically appointing the ''parent corporation'' as the filing entity. Duke urges the Commission to consider what legal means would be required to ensure that the tariff is legally a separate and severable tariff for each member of a family.

932. Further, commenters state that there are transitional issues that the Commission should consider, such as whether existing tariffs will be superseded or cancelled and all existing service agreements migrated to the joint tariff; which corporate entity would be required to file and maintain the MBR tariff; and the extent to which affiliates may have to file separate quarterly reports due to the fact that the responsible employees are not shared (*e.g.*, regulated versus unregulated merchant employees).

933. In reply comments, EPSA reiterates its opposition to a mandatory single corporate tariff, urging the Commission to abandon the proposal because it ''poses major practical obstacles for corporate parents that own vastly differing affiliates.''[1054] EPSA contends that the Commission's premise for adopting the proposal, *i.e.*, entities within a corporate family can have conflicting tariff provisions, is mooted by the adoption of a standardized tariff. In addition, EPSA echoes implementation concerns raised by other parties, in particular: (1) The situation where a seller is a member of two corporate families; and (2) increased regulatory burden from frequent tariff amendments each time ownership changes and corporate affiliations are terminated or created.

934. Indianapolis P&L argues that affiliates should be permitted to maintain separate market-based rate tariffs for many of the reasons already cited. In addition, it contends that consolidation will increase the burden on many entities by requiring increased regulatory and legal coordination between affiliates. Whereas many utilities presently separate their utility and non-utility operations in part to comply with Commission regulations, Indianapolis P&L asserts that mandating a single tariff per corporate family would necessarily require utility and non-utility affiliates to operate in closer coordination. FirstEnergy agrees, stating that ''[t]he Commission should not expect franchised public utilities with captive customers to market power totally independently of their affiliates where they are all required to sell power to wholesale purchasers under the same tariff.''[1055]

935. Finally, some commenters state that the Commission's concerns can be satisfied through means other than a single tariff per corporate family. Duke recommends allowing affiliated utilities to operate with separate but uniform tariffs while posting on their corporate Web sites a centralized list of each of the affiliates' market-based rate tariffs. Similarly, Progress Energy suggests requiring sellers to use the standardized tariff but having them include a section identifying all affiliates with market-based rate authority and any restrictions on that authority.

Commission Determination

936. We will modify the NOPR proposal and allow sellers to elect whether to transact under a single market-based rate tariff for an entire corporate family or under separate tariffs. The benefits that the Commission hoped to realize by requiring all corporate families to consolidate their operations under one tariff will be achievable by other means, namely, by

individual market-based rate filings and are separately subject to the Commission's affiliate transactions rules, any confusion about affiliations does not justify a single tariff requirement. EEI reply comments at 30–31.

[1052] *See, e.g.*, EPSA at 41; Duke at 45–48; MidAmerican at 33–35; FirstEnergy at 27–31; Constellation at 27–29; Progress Energy at 19–23; EEI at 49. Cogentrix also expresses reservations about requiring a single corporate tariff. *See* Cogentrix/Goldman at 6–8.

[1053] *See, e.g.*, Mirant at 6–10; FirstEnergy at 27–31.

[1054] EPSA reply comments at 3–4.

[1055] FirstEnergy at 30.

having each individual seller revise its existing market-based rate tariff to include the standard tariff provisions we require in this Final Rule and by maintaining up-to-date information on sellers' affiliates through the submission of asset appendices.[1056]

937. For the benefit of those sellers that choose a single corporate tariff, we clarify that each seller should continue to report its own transactions using the docket number under which it initially received market-based rate authority.

*G. Legal Authority*

1. Whether Market-Based Rates Can Satisfy the Just and Reasonable Standard Under the FPA

Comments

938. A number of commenters challenge the Commission's authority to adopt a market-based rate regime.[1057] State AGs and Advocates contend that the courts have never actually reviewed the Commission's market-based rate program and found that it satisfies the FPA. They contend that the Commission in the NOPR cited *dictum* in *Louisiana Energy and Power Authority* v. *FERC*,[1058] noting that the petitioner in that case did not challenge the Commission's general policy of permitting market-based rates in the absence of market power. They further argue that the D.C. Circuit in *Elizabethtown Gas Company* v. *FERC*,[1059] relied on *dictum* in a prior gas case to the effect that, where markets are competitive, it is ''rational'' to assume that a seller will make ''only a normal return on its investment.'' State AGs and Advocates then criticize the D.C. Circuit's opinion, arguing that ''this sort of judicial economic theorizing does not constitute either the substantial evidence required to support orders of this Commission under the [FPA], or the 'empirical proof' required by the courts when an agency attempts to substitute competition for statutorily required regulation.'' [1060]

939. NASUCA similarly questions the Commission's reliance on *Elizabethtown Gas* as the legal foundation for its market-based rate regime. NASUCA suggests that the Supreme Court's decision in *MCI* v. *AT&T*,[1061] casts considerable doubt on the vitality of *Elizabethtown Gas* and cases that follow its apparent endorsement of market-based rates that did not consider the statutory filing issues found crucial in *MCI*. NASUCA also notes that, in another case the Commission relied on, *Mobil Oil Exploration* v. *United Distribution Co.*,[1062] the Supreme Court cited to *FPC* v. *Texaco*, where it held that just and reasonable rates cannot be determined solely by reference to market prices.[1063]

940. Some commenters argue that a finding that competitive markets exist is a prerequisite to relying upon market-based rate authority to satisfy the mandates of the FPA.[1064] Industrial Customers contend that the Commission may rely on market-based rate authority to produce just and reasonable rates if it finds that a competitive market exists and the seller lacks or has adequately mitigated market power. They submit that the duty to determine that a competitive market exists is separate and independent of the determination that a seller lacks, or has adequately mitigated, market power.

State AGs and Advocates contend that the market-based rate program offers no way to monitor whether existing competition results in just and reasonable rates, nor a way to check rates if it does not.[1065]

941. In reply, PNM/Tucson argues that the Commission need not entertain attacks on the existence of competitive power markets and the legality of market-based rates under the FPA, as they constitute collateral attacks on recent Commission decisions and the *Lockyer* opinion, and because a theoretical debate on the subject is beyond the scope of this rulemaking proceeding. PNM/Tucson asserts that those cases found that market-based rates are permissible by law and urges the Commission to reject any attacks on market-based rates generally.[1066]

942. Financial Companies respond to State AGs and Advocates' assertion that the Commission should suspend or revoke all market-based rates and return to cost-of-service ratemaking by commenting that the complaining parties mischaracterize the state of the wholesale market. Financial Companies enumerate the ''myriad of approval, reporting and other obligations'' [1067] that constitute the Commission's oversight and point out that ISOs and RTOs provide another layer of market monitoring and mitigation. They state that it is preferable to shape market power remedies addressing specific circumstances than to revoke market-based rate tariffs for all sellers.

Commission Determination

943. The Commission rejects arguments that it has no authority to adopt market-based rates or that the market-based rate program it is adopting in this rule does not comply with the FPA. The Supreme Court has held that ''[f]ar from binding the Commission, the FPA's just and reasonable requirement accords it broad ratemaking authority.* * * The Court has repeatedly held that the just and reasonable standard does not compel the Commission to use any single pricing formula in general. * * *'' [1068] It is settled law that market-based rates can satisfy the just and reasonable standard of the FPA, as most recently reaffirmed by the Ninth Circuit in *Lockyer* and *Snohomish*,[1069] and the court in *Lockyer* expressly denied a ''facial challenge to the market-based [rate] tariffs,'' as discussed below.

944. In the *Lockyer* court's analysis of the Commission's market-based rate authority, the Ninth Circuit cited the Supreme Court's determination in *Mobil Oil Exploration.* It also noted that the use of market-based rate tariffs was first approved (by the courts) as to sellers of natural gas in *Elizabethtown Gas,* then as to wholesale sellers of electricity in *LEPA.*

945. Commenters have also argued that the proposed rule impermissibly relies solely on the market to determine just and reasonable rates, as was the case in *Texaco.* We reject these arguments as well.

946. In *Texaco,* the Supreme Court found that the Natural Gas Act (NGA) permits the indirect regulation of small-producer rates.[1070] The Supreme Court

[1056] The asset appendix is discussed above in Implementation Process.

[1057] *E.g.*, State AGs and Advocates at 3–13, 18–28, 38–40; NASUCA at 33–37.

[1058] 141 F.3d 364, 365 (D.C. Cir. 1998) (*LEPA*).

[1059] 10 F.3d 866, 870 (D.C. Cir. 1993) (*Elizabethtown Gas*).

[1060] State AGs and Advocates at 8–9.

[1061] 512 U.S. 218 (1994) (*MCI*).

[1062] 498 U.S. 211 (1991).

[1063] 417 U.S. 380, 397 (1974).

[1064] Industrial Customers at 3–12; NRECA at 6–10; State AGs and Advocates reply comments at 17–22.

[1065] State AGs and Advocates reply comments at 18–19, citing *Farmers Union* (finding reliance on existing competition, with no monitoring or mitigation, unacceptable).

[1066] PNM/Tucson reply comments at 3–4 (citing *Lockyer* and the underlying Commission orders, *State of California, ex rel. Bill Lockyer* v. *British Columbia Power Exchange Corp.*, 99 FERC ¶ 61,247, *order on reh'g*, 100 FERC ¶ 61,295 (2002)).

[1067] Financial Companies reply comments at 10.

[1068] See *Mobil Oil Exploration* v. *United Distribution Co.,* 498 U.S. 211, 224 (1991) (Mobil Oil Exploration), citing *FPC* v. *Hope Natural Gas Co.,* 320 U.S. 591, 602 (1944); *FPC* v. *Natural Gas Pipeline Co.,* 315 U.S. 575, 586 (1942); Permian Basin Area Rate Cases, 390 U.S. 747, 776–77 (1968) (Permian); Texaco; *Mobil Oil Corp.* v. *FPC,* 417 U.S. 283, 308 (1974).

[1069] *Public Utility District No. 1 of Snohomish County, Washington* v. *FERC,* 471 F.3d 1053 (9th Cir. 2006) (Snohomish).

[1070] Cases under the NGA and the FPA are typically read *in pari materia. See, e.g., FPC* v. *Sierra Pacific Power Company,* 350 U.S. 348, 353

Continued

explained that ''[t]he Act directs that all producer rates be just and reasonable but it does not specify the means by which that regulatory prescription is to be attained. That every rate of every natural gas company must be just and reasonable does not require that the cost of each company be ascertained and its rates fixed with respect to its own costs.'' [1071] The Supreme Court noted that it had sustained rate regulation based on setting area rates that were based on composite cost considerations, citing its decision in *FPC* v. *Hope Natural Gas Co.* [1072] The Supreme Court further explained, with respect to the prior area rate cases, ''we recognized that encouraging the exploration for and development of new sources of natural gas was one of the aims of the Act and one of the functions of the Commission. The performance of this role obviously involved the rate structure and implied a broad discretion for the Commission.'' [1073] Quoting *Permian Basin*, the Supreme Court added that ''[i]t follows that ratemaking agencies are not bound to the service of any single regulatory formula; they are permitted, unless their statutory authority otherwise plainly indicates, 'to make the pragmatic adjustments which may be called for by particular circumstances.' '' [1074]

947. The *Texaco* Court further stated that ''the prevailing price in the marketplace cannot be the final measure of 'just and reasonable' rates mandated by the Act.'' [1075] But, ''[t]his does not mean that the market price of gas would never, in an individual case, coincide with just and reasonable rates or not be a relevant consideration in the setting of area rates.'' [1076]

948. In *Elizabethtown Gas,* a decision relying on *Texaco,* the D.C. Circuit addressed a Commission order approving a restructuring settlement under which Transcontinental Gas Pipeline Corporation (Transco) would no longer sell gas bundled with transportation, but would sell gas at the wellhead or pipeline receipt point, to be transported as the buyer sees fit. The sales would be market-based (negotiated) and the rates for transportation on Transco's system would be cost-of-service based. In approving the settlement, the Commission had ''determined that Transco's markets are sufficiently competitive to preclude the pipeline from exercising significant market power in its merchant function and to assure that gas prices are 'just and reasonable' within the meaning of the NGA section 4.'' [1077] The Commission also ''authorized Transco in advance 'to establish and to change' individually negotiated rates free of customer challenge under section 4 of the NGA; the 'only further regulatory action' possible under the settlement is the Commission's review of Transco's prices under section 5 of the Act, upon the Commission's own motion or upon the complaint of a customer that is not a party to the settlement.'' [1078]

949. In *Elizabethtown Gas,* the D.C. Circuit upheld the Commission's approval of market-based pricing, holding that ''nothing in *FPC* v. *Texaco* precludes the FERC from relying upon market-based pricing.'' [1079] The D.C. Circuit explained that in *Texaco,* the Commission had failed to even mention the ''just and reasonable'' standard and appeared to apply only the ''standard of the marketplace'' in reviewing the reasonableness of the rate (which the Supreme Court had found to be unacceptable). Thus, the D.C. Circuit explained with approval, ''the FERC has made it clear that it will exercise its section 5 authority (upon its own motion or upon that of a complainant) to assure that a market (*i.e.*, negotiated) rate is just and reasonable.'' [1080]

950. The D.C. Circuit noted that the Commission had specifically found that Transco's markets are sufficiently competitive to preclude it from exercising significant market power. It further noted that the Commission had explained that Transco would be providing comparable transportation for all gas supplies and that ''adequate divertible gas supplies exist'' to assure that Transco would have to sell at competitive prices. Thus, the D.C. Circuit concluded that Transco would not be able to raise its price above the competitive level without losing substantial business. ''Such market discipline provides strong reason to believe that Transco will be able to charge only a price that is 'just and reasonable' within the meaning of section 4 of the NGA.'' [1081]

951. Likewise in *LEPA,* the D.C. Circuit affirmed the Commission's approval of an application by Central Louisiana Electric Company (CLECO) to sell electric energy at market-based rates. The D.C. Circuit found reasonable the Commission's conclusion that there are no market power considerations that should bar CLECO's application to sell at market-based rates. It also found reasonable the Commission's conclusion that even if CLECO had participated in oligopolistic behavior in the past, the Commission's new open access transmission rules had transformed the competitive environment. The D.C. Circuit noted that ''competitors outside the current, alleged oligopoly will now be able to transmit power into CLECO's territory on nondiscriminatory terms.'' [1082] Thus, according to the D.C. Circuit, the Commission reasonably predicted that it was ''unlikely that 'energy suppliers will decline to participate in the emerging competitive markets.' '' [1083] Finally, the D.C. Circuit viewed favorably the Commission's provision of a safeguard in the event that its predictions are wrong:

> FERC notes that should the Commission's sanguine predictions about market conduct turn out to be incorrect, LEPA can file a new complaint for any abuses of market power that do occur. While this escape hatch might be insufficient if LEPA had shown a substantial likelihood that FERC's predictions would prove incorrect, it provides an appropriate safeguard against the uncertainties of FERC's prognostications where there has been no such showing.[1084]

952. In the market-based rate program adopted in this rule and through other Commission actions, unlike the situation in *Texaco,* the Commission is not relying solely on the market, without adequate regulatory oversight, to set rates. Rather, it has adopted filing requirements (EQRs and change in status filings for all market-based rate sellers, regularly scheduled updated market power analyses for all Category 2 market-based rate sellers, [1085]), new

(1956); *Arkansas-Louisiana Gas Company* v. *Hall,* 453 U.S. 571, 578 n.7 (1981).

[1071] 417 U.S. at 387.

[1072] 320 U.S. at 602 (''Under the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling.'').

[1073] *Id.* at 388.

[1074] *Id.* at 389, citing *Permian,* 390 U.S. at 776–777.

[1075] *Id.*

[1076] *Id.*

[1077] 10 F.3d at 869.

[1078] *Id.*

[1079] *Id.* at 870.

[1080] *Id.*

[1081] *Id.* at 871.

[1082] 141 F.3d at 370.

[1083] *Id.* (quoting Commission order).

[1084] *Id.* at 370–71 (footnotes and citations omitted).

[1085] In this Final Rule, the Commission creates two categories of sellers. Category 1 sellers (wholesale power marketers and wholesale power producers that own or control 500 MW or less of generation in aggregate per region; that do not own, operate or control transmission facilities other than limited equipment necessary to connect individual generation facilities to the transmission grid (or have been granted waiver of the requirements of Order No. 888); that are not affiliated with anyone that owns, operates or controls transmission facilities in the same region as the seller's generation assets; that are not affiliated with a franchised public utility in the same region as the seller's generation assets; and that do not raise other market manipulation rules, and a significantly enhanced market oversight and enforcement division to help oversee potential market manipulation. In addition, for sellers in RTO/ISO organized markets, Commission-approved tariffs contain specific market rules designed to prevent or mitigate exercises of market power.

953. In *Lockyer,* the Ninth Circuit cited with approval the Commission's dual requirement of an *ex ante* finding of the absence of market power and sufficient post-approval reporting requirements and found that the Commission did not rely on market forces alone in approving market-based rate tariffs. The Ninth Circuit held that this dual requirement was ''the crucial difference'' between the Commission's regulatory scheme and the FCC's regulatory scheme, remanded in *MCI,* which had relied on market forces alone in approving market-based rate tariffs.[1086] The Ninth Circuit thus held that ''California's facial challenge to market-based tariffs fails'' and ''agree[d] with FERC that both the Congressionally enacted statutory scheme, and the pertinent case law, indicate that market-based tariffs do not per se violate the FPA.'' [1087] The Ninth Circuit determined that initial grant of market-based rate authority, together with ongoing oversight and timely reconsideration of market-based rate authorization under section 206 of the FPA, enables the Commission to meet its statutory duty to ensure that all rates are just and reasonable.[1088] While the court in *Lockyer* found that the Commission's market-based rate reporting requirements were not followed in that particular case, it did not find those reporting requirements invalid and, in fact, upheld the Commission's market program as complying with the FPA. The market-based rate requirements and oversight adopted in this rule are more rigorous than those reviewed by the *Lockyer* court.

954. Accordingly, the Commission rejects the position of commenters arguing that the Commission lacks authority to continue to permit market-based rates for wholesale sales of electricity. The courts have sustained the Commission's finding that market-based rates are one method of setting just and reasonable rates under the FPA. As supplemented by this Final Rule, the Commission finds that the market-based rate program complies with the statutory and judicial standards for acceptable market-based rates. We will retain our policy of granting market-based rate authority to sellers without market power under the terms and conditions set forth in this Final Rule and the Commission's regulations.

955. Further, we will retain our approach to determining whether a seller should receive authorization to charge market-based rates, as modified by the Final Rule, by analyzing seller-specific market power. The Commission has a long-established approach when a seller applies for market-based rate authority of focusing on whether the seller lacks market power.[1089] This approach, combined with our filing requirements (EQRs, change of status filings, and regularly scheduled updated market power analyses for Category 2 sellers) and ongoing monitoring through our enforcement office and complaints filed pursuant to FPA section 206, allows us to ensure that market-based rates remain just and reasonable. Moreover, for sellers in RTO/ISO organized markets, the Commission has in place market rules to help mitigate the exercise of market power, price caps where appropriate, and RTO/ISO market monitors to help oversee market behavior and conditions. As explained in our earlier discussion, we believe that the market-based rate program fully complies with judicial precedent.

Consistency of Market-Based Rate Program With FPA Filing Requirements

Comments

956. State AGs and Advocates contend that the Commission's market-based rate program fails to comply with the FPA in several ways: (1) It ignores the FPA mandate that all rates and contracts, as well as all changes in rates and contracts, must be filed in advance and made open to the public for prior review, and instead allows a seller to simply report rates after-the-fact or, in some cases, not at all; (2) it eliminates the statutory mandate that all rate increases must be noticed by filing 60 days in advance so that they can be reviewed and, if warranted, suspended for up to five months, set for hearing with the burden of proof on the seller, and made subject to refund pending the outcome of the hearing; (3) it provides no objective or independent standard for determining whether ''competitive'' market-based rates are in fact ''just and reasonable;''[1090] (4) it provides no standard for determining whether market rates are unduly preferential or discriminatory; and (5) it provides no way for consumers in most cases to know what the ''just and reasonable'' rate will be in advance.[1091] They also contend that the legal presumptions that follow from the Commission's market power screens would unduly shift the burden of demonstrating the existence of market power to intervenors and away from the Commission. They argue that, until an appropriate methodology for predicting and checking market power is in place, the Commission must suspend its market-based rate regime and return to cost-of-service rates for all wholesale sales of electric power.

957. NASUCA objects that the proposed rules would prohibit utilities from filing new wholesale energy contracts,[1092] an apparent reference to the Commission's policy, since the issuance of Order No. 2001,[1093] that long-term affiliate sales contracts under a seller's market-based rate tariff are not to be filed.[1094] According to NASUCA, by not requiring sellers to file long-term market-based rate sales contracts, the Commission effectively precludes the

vertical market power issues) would not be required to file a regularly scheduled updated market power analysis, but would be subject to the change in status requirement. Category 2 sellers consist of all sellers that do not qualify as Category 1 sellers.

[1086] *Id.* at 1013.

[1087] *Id.* at 1013 & n.5; *id.* at 1014 (''The structure of the tariff complied with the FPA, so long as it was coupled with enforceable post-approval reporting that would enable FERC to determine whether the rates were 'just and reasonable' and whether market forces were truly determining the price.'').

[1088] *See Snohomish,* 471 F.3d at 1080 (in which the Ninth Circuit discusses its decision in *Lockyer*). In *Snohomish,* the Ninth Circuit explained, ''As in *Lockyer*, we do not dispute that FERC may adopt a regulatory regime that differs from the historical cost-based regime of the energy market, or that market-based rate authorization may be a tenable choice if sufficient safeguards are taken to provide for sufficient oversight.'' *Id.* at 1086.

[1089] *See, e.g., Heartland Energy Services, Inc.,* 68 FERC ¶ 61,223, at 62,060–61 (1994); *Louisville Gas and Electric Co.,* 62 FERC ¶ 61,016, at 61,143 n.16 (1993) (and the cases cited therein); *Citizens Power & Light Corp.,* 48 FERC ¶ 61,210, at 61,776 & n.11 (1989); *Pacific Gas and Electric Co.* (Turlock), 42 FERC ¶ 61,406, at 62,194–98, *order on reh'g,* 43 FERC ¶ 61,403 (1988); *Pacific Gas and Electric Co. (Modesto),* 44 FERC ¶ 61,010, at 61,048–49, *order on reh'g,* 45 FERC ¶ 61,061 (1988). *See* also, *e.g., LEPA,* 141 F.3d at 365; *Consumers Energy Co.,* 367 F.3d 915 at 922–23 (D.C. Cir. 2004) (upholding Commission orders granting market-based rate authority, noting that the Commission's longstanding approach is to assess whether applicants for market-based rate authority do not have, or have adequately mitigated, market power).

[1090] State AGs and Advocates express doubt that the rate of return for power sold from a highly depreciated coal plant in an auction process at a market price equal to the marginal cost of a new, gas-fired plant could be within a zone of reasonableness. State AGs and Advocates at 25–26.

[1091] *Id.* at 19–20.

[1092] NASUCA at 32–33.

[1093] *Revised Public Utility Filing Requirements,* Order No. 2001, 67 FR 31043 (May 8, 2002), FERC Stats. & Regs., Regs. Preambles 2001–2005 ¶ 31,127 (2002). *See* 18 CFR 35.10b.

[1094] NASUCA at 27–29.

public and others from objecting before the rates take effect. Additionally, NASUCA states that there is no statutory basis for a Commission rule directing sellers not to file their rates when the statute says exactly the opposite.[1095] AARP similarly comments that the Commission's policy of monitoring long-term market-based sales through quarterly reports is too little oversight too late to ensure that such rates are just and reasonable. AARP argues that the Commission should reconsider its policy on affiliate transactions and asserts that all affiliate contracts should be filed and reviewed under section 205 to comply with the express requirements under the FPA.[1096]

958. NASUCA also argues that the proposed rule allows sellers with cost-based rates to declare their own rates without filing them, subject to Commission review when the sales are for less than one year. It contends that the burden of proof, under *Farmers Union Central Exchange, Inc.* v. *FERC*[1097] and *Texaco*,[1098] is on the Commission to demonstrate empirical proof that consumers are provided the ''complete, effective and permanent bond of protection from excessive rates'' that the statute anticipates.[1099]

Commission Determination

959. We reject State AGs and Advocates' arguments that the Commission's market-based rate program fails to comply with the FPA. Contrary to State AGs and Advocates' contention that the Commission's market-based rate program ''ignores the FPA mandate that all rates and contracts, as well as all changes in rates and contracts, must be filed in advance and made open to the public for prior review'' and instead ''allows sellers to simply 'report' rates after-the-fact, or in some cases, not at all,''[1100] as the courts have found, the Commission's market-based rate program does not violate the FPA's filing requirements. The FPA requires that every public utility file with the Commission ''schedules showing all rates and charges for any transmission or sale subject to the jurisdiction of the Commission,''[1101] but it explicitly leaves the timing and form of those filings to the Commission's discretion. Public utilities must file ''schedules showing all rates and charges'' under ''such rules and regulations as the Commission may prescribe,'' and ''within such time and in such form as the Commission may designate.''[1102]

960. We note that the courts have recognized the Commission's discretion in establishing its procedures to carry out its statutory functions. For example, the Ninth Circuit, in denying a California Commission request to order the Commission to adopt different market-based rate tariff reporting requirements, observed:

> Congress specified that filings be made ''within such time and with such form'' and under ''such rules and regulations as the Commission may prescribe.'' 16 U.S.C. § 824d(c). Thus, so long as FERC has approved a tariff within the scope of its FPA authority, it has broad discretion to establish effective reporting requirements for administration of the tariff.[1103]

961. The market-based rate tariff, with its appurtenant conditions and requirement for filing transaction-specific data in EQRs, is the filed rate. As the Commission has held, if every service agreement under a previously-granted market-based rate authorization had to be filed for prior approval, then the original market-based rate authorization would be a pointless exercise.[1104]

962. We also disagree with State AGs and Advocates' argument that the market-based rate program eliminates the statutory mandate that all rate increases be noticed by filing 60 days in advance and, if warranted, suspended for up to five months, set for hearing with the burden of proof on the seller, and made subject to refund pending the outcome of the hearing. The Commission has developed a thorough process to evaluate the sellers that it authorizes to enter into transactions at market-based rates. Under the market-based rate program, the rate change is initiated when a seller applies for authorization of market-based rate pricing. All applications are publicly noticed, entitling parties to challenge a seller's claims. At that time, there is an opportunity for a hearing, with the burden of proof on the seller to show that it lacks, or has adequately mitigated, market power, and for the imposition of a refund obligation. In addition, if a seller is granted market-based rate authority, it must comply with post-approval reporting requirements, including the quarterly filing of transaction-specific data in EQRs,[1105] change of status filings for all sellers, and regularly-scheduled updated market power analyses for Category 2 sellers.

963. In addition, we disagree with State AGs and Advocates' arguments that the Commission failed to show how competitive market-based rates are just and reasonable and not unduly discriminatory or preferential. The standard for judging undue discrimination or preference remains what it has always been: Disparate rates or service for similarly situated customers.[1106] As the Commission has held in prior cases, and as the courts have upheld, rates that are established in a competitive market can be just, reasonable and not unduly discriminatory.[1107] Rates do not have to be set by reference to an accounting cost of service to be just, reasonable and not unduly discriminatory. When the Commission determines that a seller lacks market power, it is therefore making a determination that the resulting rates will be established through competition, not the exercise of market power. Furthermore, the Commission's market-based rate program includes many ongoing regulatory protections designed to ensure that rates are just and reasonable and not unduly discriminatory or preferential. The filing and reporting requirements incorporated into the market-based rate program (EQRs, change in status filings, regularly-scheduled updated market power analyses) help the Commission to prevent, to discover and to remedy exercises of market power and unduly discriminatory rates. In addition, the adoption of *pro forma* transmission tariff provisions that apply industry-

[1095] *Id.* at 28.

[1096] AARP at 12.

[1097] 734 F.2d 1486 (D.C. Cir. 1984), cert. denied sub nom. *Williams Pipe Line Company* v. *Farmers Union Central Exchange, Inc.*, 469 U.S. 1034 (1984) (Farmers Union).

[1098] 417 U.S. 380 (1974).

[1099] NASUCA cites *Atlantic Ref. Co.* v. *Pub. Serv. Comm'n of State of N.Y.*, 360 U.S. 378, 388 (1959).

[1100] State AGs and Advocates at 19.

[1101] 16 U.S.C. 824d(c).

[1102] *Id.*

[1103] *Lockyer,* 383 F.3d at 1013. *See also Wabash Valley Power Association* v. *FERC*, 268 F.3d 1105, 1115 (citing with approval the Commission's authority to fix just and reasonable rates under section 206 as a condition of its market-based rate authorization); *Environmental Action* v. *FERC,* 996 F.2d 401, 407–08 (D.C. Cir. 1993) (in which the D.C. Circuit recognized ''the Commission's determination to streamline its regulatory process to keep pace with advances in information technology. Ratemaking is a time-consuming process.'').

[1104] *GWF Energy LLC*, 98 FERC ¶ 61,330, at 62,390 (2002).

[1105] The Ninth Circuit found the pre-EQR quarterly reporting requirements to be ''integral to the [market-based rate] tariff'' and that they, together with the Commission's initial approval of market-based rate authority, comply with the FPA's requirements. *Lockyer*, 383 F.3d at 1016. As discussed elsewhere in this Final Rule, through the EQRs, the Commission has enhanced and updated the post-transaction quarterly reporting filing requirements that were in place during the period at issue in *Lockyer.*

[1106] *See, e.g., Southwestern Electric Cooperative, Inc.* v. *FERC*, 347 F.3d 975, 981 (D.C. Cir. 2003).

[1107] *See, e.g., Lockyer*, 383 F.3d at 1012–13; *Tejas Power Corp.* v. *FERC*, 980 F.2d 998, 1004 (D.C. Cir. 1990).

wide ensures that potential customers are treated similarly in obtaining transmission access to energy providers. Moreover, Commission-approved RTOs and ISOs run real-time energy markets under Commission-approved tariffs.[1108] These single price auction markets set clearing prices on economic dispatch principles, to which various safeguards have been added to protect against anomalous bidding.

964. Thus, the Commission, through its ongoing oversight of market-based rate authorizations and market conditions, may take steps to address seller market power or modify rates should those steps be necessary. For example, based on its review of updated market power updates, its review of EQR filings made by market-based rate sellers, and its review of required notices of change in status, the Commission may institute a section 206 proceeding to revoke a seller's market-based rate authorization if it determines that the seller may have gained market power since its original market-based rate authorization. The Commission may also, based on its review of EQR filings or daily market price information, investigate a specific utility or anomalous market circumstances to determine whether there has been any conduct in violation of RTO/ISO market rules or Commission orders or tariffs, or any prohibited market manipulation, and take steps to remedy any violations. These steps could include, among other things, disgorgement of profits and refunds to customers if a seller is found to have violated Commission orders, tariffs or rules, or a civil penalty paid to the United States Treasury if a seller is found to have engaged in prohibited market manipulation or to have violated Commission orders, tariffs or rules.

965. In the NOPR that preceded Order No. 2001, the Commission noted that it needed to make changes to keep abreast of developments in the industry, *e.g.*, it had approved umbrella tariffs for market-based rates by public utilities and there had been a significant increase in the number of section 205 filings after the Commission's open access initiatives in Order Nos. 888 and 889.[1109] The Commission explained:

> Under the Commission's current filing requirements in 18 C.F.R. Part 35, individual service agreement filings associated with approved tariffs require a significant amount of time, effort, and expense on the part of public utilities to prepare and serve on their customers and the Commission. These individual filings also require a significant amount of staff time and effort associated with docketing, noticing, loading the information onto RIMS, and other processing tasks. Further, the information contained in such filings that is most relevant to customers and the Commission could also be provided in an alternative, streamlined form, thus continuing to satisfy the requirements of FPA section 205(c), but in a more efficient manner. Accordingly, we propose to replace the filing of individual service agreements and Quarterly Transaction Reports with the filing of an electronic Index of Customers. This format will greatly increase the accessibility and usefulness of the relevant data, which will confer greater benefits to the public.[1110]

966. The Commission implemented the revised filing requirements in Order No. 2001. In so doing, it further explained that:

> The revised filing public utility requirements adopted in this Final Rule create a level playing field vis-à-vis the filing requirements applicable to traditional utilities and power marketers. While the data to be reported in the data sets reduces public utilities' overall reporting burden as compared to existing requirements, it is hoped that the Electric Quarterly Reports' more accessible format will make the information more useful to the public and the Commission will better fulfill the public utilities' responsibility under FPA section 205(c) to have rates on file in a convenient form and place. The data should provide greater price transparency, promote competition, enhance confidence in the fairness of markets, and provide a better means to detect and discourage discriminatory practices.[1111]

967. Thus, we find that the multiple layers of filing and reporting requirements incorporated into the market-based rate program meet the filing requirements of the FPA and, in conjunction with our enhanced market oversight and enforcement functions within the Commission, as well as the ability of the public to file section 206 complaints, provide adequate protection from excessive rates. Given our broad discretion to determine the procedures to carry out our statutory duties, our market-based rate program fully complies with the requirements of the FPA.[1112]

968. Although State AGs and Advocates also argue that the legal presumptions that follow from the Commission's market power screens would unduly shift the burden of demonstrating the existence of market power to intervenors, the Commission previously addressed and rejected this argument. On rehearing of the April 14 Order, the Commission explained that nothing in that order shifts the burden of proof that section 205 imposes on the filing utility. Passing both screens or failing one merely establishes a rebuttable presumption. To challenge a seller who passes both screens, the intervenor need not conclusively prove that the seller possesses market power. Rather, the intervenor need only meet a burden of going forward with evidence that rebuts the results of the screens. At that point, the burden of going forward would revert back to the seller to prove that it lacks market power.[1113] Ultimately, the burden of proof under section 205 belongs to the seller.

969. With respect to NASUCA's and AARP's concern about long-term affiliate sales contracts not being filed, we note that since 2002, the Commission's regulations have provided that long-term market-based rate power sales service agreements, with affiliates or otherwise, are not to be filed with the Commission.[1114] Although commenters acknowledge that the Commission first considers in a separate proceeding whether to authorize affiliate transactions, they believe that the Commission should nevertheless review the resulting rates in a proceeding under FPA section 205 before they go into effect.

970. NASUCA and AARP have not convinced us that this practice needs to be modified as a legal or policy matter. Our market-based rate program incorporates numerous protections against excessive rates, regardless of the identities of the parties to a transaction, and commenters do not provide any compelling reason why affiliate transactions should be treated any differently. To the extent that a

[1108] In response to State AGs and Advocates' argument about the rate of return for a seller receiving a market clearing price for power sold in an auction process, the issue does not concern whether a particular seller should have market-based rate authority, and it is more appropriately addressed in the context of an RTO/ISO proceeding rather than in this rulemaking proceeding.

[1109] *Open Access Same-Time Information System and Standards of Conduct*, Order No. 889, 61 FR 21737 (1996), FERC Stats. & Regs., Regs. Preambles ¶ 31,037 (1996), *order on reh'g*, Order No. 889–A, 62 FR 12484 (1997), FERC Stats. & Regs., Regs. Preambles ¶ 31,049 (1997), *reh'g denied*, Order No. 889–B, 81 FERC ¶ 61,253 (1997), *aff'd in part and rev'd in 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).

[1110] *Revised Public Utility Filing Requirements, Notice of Proposed Rulemaking*, FERC Stats. & Regs., Proposed Regulations 1999–2003, ¶ 32,554 at 34,062 (2001).

[1111] Order No. 2001, FERC Stats. & Regs., Regs. Preambles 2001–2005 ¶ 31,127 at P 31.

[1112] Moreover, the decision to eliminate the filing of market-based rate contracts was made almost five years ago in a generic rulemaking proceeding that was open to participation by all interested parties. Commenters' failure to raise this concern in that proceeding precludes them from attacking the Commission's well-settled practice here.

[1113] July 8 Order, 108 FERC ¶ 61,026 at P 29.

[1114] *See* 18 CFR 35.1(g) (''[A]ny market-based rate agreement pursuant to a tariff shall not be filed with the Commission'').

particular affiliate relationship presents issues of concern, they will be considered in the context of our determination whether to authorize any affiliate sales. Accordingly, we will continue to direct sellers not to file long-term market-based rate sales contracts, unless otherwise permitted by Commission rule or order.

971. Regarding NASUCA's assertion that our proposals would allow sellers with cost-based rates to declare their own rates without filing them, we emphasize that all mitigation proposals, whether based on the default cost-based rates or some other cost-based rates, must be filed with the Commission for review. As we make clear above in the Mitigation section of this Final Rule, any such filings are noticed, and interested parties are given an opportunity to intervene, comment on, or protest the submittal.

2. Whether Existing Tariffs Must Be Found To Be Unjust and Unreasonable, and Whether the Commission Must Establish a Refund Effective Date

Comments

972. NASUCA states that the Commission invokes sections 205 and 206 of the FPA as authority for the proposed action, including modifying all existing market-based rate authorizations and tariffs so they will be expressly conditioned on or revised to reflect certain new requirements. NASUCA submits that any action taken under section 206 must be prefaced by a Commission finding that existing rates are unjust and unreasonable and the fixing of a refund effective date. It argues that the Commission has failed to make express findings necessary to support its proposal to modify all existing market-based rate tariffs under section 206 or to explain how it can modify the existing tariffs without finding that they are not just and reasonable and establishing a refund effective date.[1115]

Commission Determination

973. As discussed above in the MBR Tariff section, in requiring all sellers to revise their existing market-based rate tariffs to include certain standard provisions, the Final Rule finds that continuing to allow basic inconsistencies in the market-based rate tariffs on file with the Commission is unjust and unreasonable. Thus, NASUCA's concern in that regard is addressed.

974. We disagree with NASUCA that we must establish a refund effective date because we are establishing rules under section 206. Even if section 206 were read to require the establishment of a refund effective date in rulemakings initiated under section 206, rather than only in case-specific section 206 investigations initiated by complaints or *sua sponte* by the Commission,[1116] we have broad discretion to adopt generic policy or make generic findings through either a rulemaking or adjudication, and we have discretion whether to order refunds.[1117] This proceeding is not an adjudicatory investigation of public utilities' existing market-based rate tariffs for which refunds will be required. Rather, we are modifying existing market-based rate tariffs prospectively only through this rulemaking.[1118] Accordingly, the establishment of a refund effective date in this rulemaking would be meaningless.

*H. Miscellaneous*

1. Waivers

Commission Proposal

975. The Commission has granted certain entities with market-based rate authority, such as power marketers and independent or affiliated power producers, waiver of the Commission's Uniform System of Accounts (USofA) requirements, specifically waiver of Parts 41, 101, and 141 of the Commission's regulations.[1119] The Commission has also granted blanket approval under Part 34 of the Commission's regulations for future issuances of securities and assumptions of liability where the entity seeking market-based rate authority, such as a power marketer or power producer, is not a franchised public utility.

976. In the NOPR, the Commission noted that, as the development of competitive wholesale power markets continues, independent and affiliated power marketers and power producers are playing more significant roles in the electric power industry. In light of the evolving nature of the electric power industry, the Commission sought comment on the extent to which these entities with market-based rate authority should be required to follow the USofA; what financial information, if any, should be reported by these entities; how frequently it should be reported; and whether the Part 34 blanket authorizations continue to be appropriate.

977. The Commission noted that some sellers have had their market-based rate authority revoked, or have elected to relinquish their market-based rate authority after a presumption of market power, and have begun or resumed selling power at cost-based rates. As discussed in the April 14 Order, any waivers previously granted in connection with those sellers' market-based rate authority are no longer applicable. Thus, the Commission currently rescinds any accounting and reporting[1120] waivers for mitigated sellers in the mitigated control area. Similarly, the Commission stated in the April 14 Order that it would rescind any blanket authorizations under Part 34 for the mitigated seller and its affiliates. In the NOPR, the Commission proposed that, in the case of any affiliates, this would entail rescission of blanket authorizations in all geographic areas, not just the mitigated control area.

978. The Commission proposed in the NOPR that any repeal of previously granted waivers become effective 60 days from the date of an order repealing such waivers in order to provide the affected utility with time to make the necessary filings with the Commission and to allow for an orderly transition from selling under market-based rates to cost-based rates. The Commission sought comment on that proposal. The Commission also sought input regarding any difficulties sellers may have when transitioning to cost-based rates and whether a prior waiver of the accounting regulations would leave them without adequate data to come into conformance with the accounting rules.

[1115] NASUCA at 32.

[1116] The Congressional intent of the Regulatory Fairness Act of 1988 (RFA), which added the refund effective date provision to section 206, was to expedite the resolution of complaint proceedings. Congress believed that, pre-RFA, public utilities had little incentive to settle meritorious section 206 complaints since any relief was prospective only, and the public utilities kept any revenues collected during the pendency of a section 206 proceeding. The purpose of the legislation was to "correct this problem by giving FERC the authority to order refunds, subject to certain limitations." S. Rep. No. 491, 100th Cong., 2d Sess. 3 (1988), *reprinted in* 1988 U.S.C.C.A.N. 2684, 2685. In so doing, Congress left it to the Commission's discretion to determine when the public interest would be served by requiring refunds under section 206, stating "Because the potential range of these situations cannot be fully anticipated, no attempt has been made to enumerate them here." S. Rep. No. 491, 100th Cong., 2d Sess. 6, *reprinted in* 1988 U.S.C.C.A.N. 2688. Nowhere in the Senate Report does Congress mention setting refund effective dates in rulemakings.

[1117] *See, e.g., Lockyer*, 383 F.3d at 1016.

[1118] *E.g., Wisconsin Gas Co.* v. *FERC*, 770 F.2d 1144, 1166 (D.C. Cir. 1985); *SEC* v. *Chenery*, 332 U.S. 194, 202–03, *reh'g denied*, 332 U.S. 747 (1947).

[1119] Part 41 pertains to adjustments of accounts and reports; Part 101 contains the Uniform System of Accounts for public utilities and licensees; Part 141 describes required forms and reports.

[1120] *See* 18 CFR 41.10–41.12, 141.1, 141.2 and 141.400.

a. Accounting Waivers

Comments

979. The majority of commenters who comment on this topic urge the Commission to retain existing waivers of the accounting regulations.[1121] They submit that the Commission's accounting requirements are only relevant when the utility or marketer that is being regulated charges cost-based rates. EPSA states that where a market-based rate seller neither has cost-of-service rates nor captive customers from which to recover cost-of-service rates, requiring such entities to comply with the USofA would be burdensomely expensive and would serve no purpose. The commenters explain that there has been no change in the industry that warrants a departure from the Commission's precedent. Commenters state that a change in policy would serve no public benefit, and the costs that such market-based rate sellers would have to incur in order to collect and report such data would substantially outweigh the benefit of collecting and reporting it.

980. Financial Companies state that there is no reason for the Commission to run the risk of discouraging participation in the energy markets and chilling investment by requiring power marketers and power producers who currently lack market power to comply with the USofA absent concrete evidence that the wholesale power markets are being harmed by the Commission's current practice of granting waivers or blanket authority.[1122]

981. Absent special circumstances, Sempra supports the current waivers and explains that the electric quarterly transaction reports submitted pursuant to Order No. 2001 [1123] provide detailed information regarding transactions entered into by entities authorized to make market-based rate sales. Sempra also notes that the retention of these waivers for market-based rate entities is also consistent with the treatment of power marketers and exempt wholesale generators (EWGs) under the Public Utility Holding Company Act of 2005 and the Commission's regulations promulgated thereunder.[1124]

982. APPA/TAPS suggest that the Commission provide waivers to Category 1 sellers, but not for Category 2 sellers.[1125] In response to the Commission's question about the orderly transition from market-based to cost-based rates and the role that waivers may play in making that transition more difficult, APPA/TAPS suggest that Category 2 sellers are more likely than Category 1 sellers to lose market-based rate authority and find themselves subject to cost-based rates; accordingly, not providing the waivers for Category 2 sellers should address these transition concerns.

Commission Determination

983. We will continue the Commission's historical practice of granting waiver of Parts 41, 101, and 141 of the Commission's regulations to certain entities with market-based rate authority. We agree with EPSA that little purpose would be served to require compliance with accounting regulations for entities that do not sell at cost-based rates and do not have captive customers. Such entities typically include power marketers and independent and affiliated power producers that are not franchised public utilities.[1126]

984. We conclude that the costs of complying with the Commission's USofA requirements and, specifically Parts 41, 101, and 141 of the Commission's regulations, outweigh any incremental benefits of such compliance where the seller only transacts at market-based rates.[1127] Further, the risk of discouraging participation in the energy markets and the potential chilling effect on investment caused by requiring power marketers and power producers, who do not otherwise have a cost-based rate on file with the Commission, to comply with the USofA outweigh the added oversight the Commission might gain in this regard.

985. As we have done in the past, previously granted waivers of the accounting requirements will continue to be rescinded where a seller is found to have market power (or where the seller accepts a presumption of market power) and the seller proposes cost-based rate mitigation or the Commission imposes cost-based rate mitigation. Although the Commission stated in the NOPR that it would also revoke the accounting waivers for any of the mitigated seller's affiliates with market-based rates in the mitigated balancing authority area, we clarify that we will not require revocation of the accounting and reporting waivers for a power marketer affiliated with a mitigated seller where such power marketer has no assets, no cost-based rate on file, and its applicable tariff prohibits sales in the mitigated balancing authority area.[1128]

986. With regard to APPA/TAPS's suggestion that the Commission provide waivers to sellers that qualify for Category 1 and not to sellers that qualify for Category 2, we decline to adopt such an approach. While APPA/TAPS may be correct that Category 2 sellers are more likely than Category 1 sellers to possess market power, we do not grant such accounting waivers based on the size of the seller (which is, to a great extent, the critical factor in determining in which category the seller is placed). Rather, as discussed above, the waivers are granted on the basis of whether the seller is a franchised public utility or otherwise is selling at cost-based rates.

987. Finally, we note that all sellers, irrespective of accounting or other waivers, must file EQRs regarding their transactions. In addition, we agree with APPA/TAPS that any waivers in this rule do not exempt a holding company or service company from applicable reporting requirements under the Commission's PUHCA 2005 regulations.

b. Timing

Comments

988. Regarding the proposal that rescission of accounting and reporting waivers become effective 60 days from the date of an order rescinding such waivers, several commenters state that 60 days may not be enough time for sellers who have their market-based rate authority revoked, or have elected to relinquish their market-based rate

[1121] *See, e.g.*, Ameren at 23–24; EPSA at 33–36; Constellation at 23–27; EEI at 49–52; Morgan Stanley at 9–10; Ormet at 15–17; PPM at 6–7.

[1122] Financial Companies at 18.

[1123] *Revised Public Utility Filing Requirements*, Order No. 2001, 67 FR 31043 (May 8, 2002), FERC Stats. & Regs. ¶ 31,127 (2002); *reh'g denied*, Order 2001–A, 100 FERC ¶ 61,074 (2002); *reconsideration and clarification denied*, Order No. 2001–B, 100 FERC ¶ 61,342 (2002); *further order*, Order No. 2001–C, 101 FERC ¶ 61,314 (2002).

[1124] Sempra at 8–9, *citing* Public Utility Holding Company Act of 2005, Pub. L. No. 109–58 1261 *et seq.*, 119 Stat. 594 (2005) (PUHCA 2005).

[1125] However, any such waivers should not exempt a holding company or service company from applicable reporting requirements under the Commission's PUHCA 2005 regulations. APPA/TAPS at 29–30.

[1126] Likewise, we will continue to grant waiver of Subparts B and C of Part 35 of the Commission's regulations requiring the filing of cost-of-service information, except for 18 CFR 35.12(a), 35.13(b), 35.15 and 35.16. We note that this waiver would not be granted to an entity that makes sales at cost-based rates.

[1127] We have previously stated that Parts 41, 101 and 141 prescribe certain accounting and reporting requirements that focus on the assets that a utility owns, and waiver of these requirements is appropriate where the utility "will not own any such assets, its jurisdictional facilities will be only corporate and documentary, its costs will be determined by utilities that sell power to it, and its earnings will not be defined and regulated in terms of an authorized return on invested capital." *Citizens Power & Light Corp.*, 48 FERC ¶ 61,210 at 61,780 (1989).

[1128] *See, e.g.*, *APS Energy Services Company, Inc.*, 117 FERC ¶ 61,158 (2006).

authority after a presumption of market power and have begun or resumed selling power at cost-based rates, to conform to the Commission's accounting requirements.[1129]

989. EEI supports providing such companies at least six months post revocation to comply with USofA recordkeeping requirements.[1130] EEI states that the Commission should allow the companies to begin keeping records under the USofA starting at the beginning of the next calendar year, or the companies' fiscal year, if different, and to report the information the following year.[1131] argues that to put USofA in place and begin complying with the Commission's reporting requirements such as the annual FERC Form 1 and quarterly FERC Form No. 3–Q takes substantial company time and resources. EEI explains that companies must put the necessary accounts and reporting formats in place within their accounting systems. This involves substantial training of staff, modification of accounting software, testing to ensure proper internal controls under the Sarbanes Oxley Act of 2002,[1132] and review by company management and internal and external auditors to ensure accuracy under the securities laws and the Sarbanes Oxley Act. EEI submits that these measures can be quite costly—in the millions of dollars for larger companies—and they take time to implement.

990. Constellation supports the 60-day transition period as reasonable but seeks clarification that under this approach the entity would be required to (1) Maintain its accounts in accordance with the Commission's USofA only for periods beginning at the end of such transition period, and (2) obtain specific authorization for securities to be issued, or liabilities to be assumed, subsequent to the end of such transition period.[1133]

Commission Determination

991. We adopt the NOPR proposal that rescission of waivers of Parts 41, 101 and 141 of the Commission's regulations granted in connection with a seller's market-based rate authority will become effective 60 days from the date of an order revoking such waivers. We believe that this strikes a reasonable balance between the need to have adequate financial information on file with the Commission and the desire to provide sellers adequate time to comply.

992. In our consideration of the transition period for complying with the accounting and reporting requirements, the Commission finds that commenters have not sufficiently supported their request for a transition period of six months or more. EEI's arguments with respect to the time and money required to train staff and modify and test accounting software do not outweigh the need for the Commission to obtain financial information with regard to mitigated sellers so that we can meet our obligation under the FPA to ensure that rates remain just and reasonable and not unduly discriminatory or preferential. We note that our experience has shown that a 60-day transition period is sufficient time for a mitigated seller to comply with the accounting requirements.[1134]

993. In response to Constellation's request for clarification, we clarify that a seller losing or relinquishing its market-based rate authority will be required to maintain its accounts in accordance with the Commission's USofA [1135] and will be subject to quarterly and annual reporting requirements (FERC Form Nos. 3–Q, 1, or 1–F) [1136] as of the effective date of the rescission of such waivers, *i.e.*, 60 days from the date of the order rescinding the waivers. In this regard, such sellers will be required to comply with our accounting regulations (Part 101) beginning with the effective date of the rescission of such waiver. For quarterly reporting in FERC Form No. 3–Q, the seller will be required to submit FERC Form No. 3–Q beginning with the quarter in which the rescission of the accounting and reporting waivers becomes effective.[1137] The seller will also be required to submit a FERC Form No. 1 or 1–F, as applicable, beginning in the year in which the rescission of the accounting and reporting waivers becomes effective.[1138] For example, if the effective date of rescission occurs on May 15, the seller must make the 3–Q filing for the second quarter (April–June) at its regularly scheduled time even though it has not previously filed a Form 1.[1139] If a particular seller is unable to meet the applicable filing dates, it may petition the Commission for an extension. We will consider such requests on a case-by-case basis.

c. Part 34 Waivers Blanket Authorizations

Comments

994. In response to the Commission's inquiry regarding whether Part 34 blanket authorizations (pertaining to issuances of securities or assumptions of liabilities) continue to be appropriate, all commenters addressing the issue urge the Commission to retain its current policy.[1140] They submit that Commission oversight of securities issuances and assumptions of liabilities is only relevant for franchised public utilities and that prior authorization under section 204 is not necessary for market-based rate sellers that do not intend to "become a public service franchised providing electricity to consumers dependent upon [their] services." [1141] Financial Companies state that there is no reason for the Commission to risk adversely affecting energy markets by requiring entities that currently lack market power to secure agency approval each time they want to issue securities or assume liabilities.

995. With regard to the statement in the NOPR that the Commission will rescind blanket authorizations for the mitigated seller and its affiliates in all geographic areas, not just the mitigated control area, Duke strongly opposes rescission of blanket section 204 authorizations for all affiliates of the mitigated seller in all markets. Duke

[1129] *See* Ameren at 24; EEI at 48–49; Mirant at 15–16.

[1130] Mirant also supports providing six months to comply with the reporting requirements and states that, in addition, the Commission should grant extensions to that deadline based upon a demonstration that the entity is working in good faith to comply with the deadline but, due to factors beyond the entity's control, the deadline needs to be extended. Mirant at 15–16.

[1131] EEI at 48–49.

[1132] Sarbanes Oxley Act of 2002, Pub. L. 107–204, 116 Stat. 745.

[1133] Constellation at 33. *See also* PPL at 26–27 (supports proposal to keep waivers effective for 60 days from date of order revoking market-based rate authority).

[1134] *See Entergy Services, Inc*, 115 ¶ FERC 61,260 (2006) (revoking waivers and authorizations previously granted to certain Entergy Affiliates). Accounting systems were in place within 60-days from the effective date of the order rescinding the waivers and the company was granted an additional 30-day extension to file the upcoming quarterly report. *See Entergy Services, Inc.*, Docket No. AC06–257–000 (Nov. 21, 2006) (unpublished letter order).

[1135] 18 CFR Part 101.

[1136] *See* 18 CFR 141.1, 141.2, 141.400.

[1137] The first quarterly filing made by the seller will include information from the effective date of the rescission through the end of the calendar quarter.

[1138] The first annual filing of FERC Form No. 1 or 1–F will include information beginning with the effective date of the rescission through the end of the calendar year. Additionally, there is a requirement that goes along with these forms that requires the submission of a CPA Certification Statement (18 CFR 41.10–41.12).

[1139] In this example, the seller's 3–Q for the second quarter must reflect our accounting regulations as of May 15, the effective date of rescission of such waivers.

[1140] *See, e.g.*, Cogentrix at 3–6; PPL at 25–27; TXU at 5–7; AWEA at 4–5; Duke supplemental comments at 1–8; Powerex at 26–28.

[1141] *See* Cogentrix at 5, citing *Citizens Energy Corp.*, 35 FERC ¶ 61,336 at 61,455 (1986). Cogentrix notes that entities with such blanket authorizations do not provide the service that franchised utilities are obligated to offer to their captive customers and that FPA section 204 and 18 CFR Part 34 are intended to protect.

urges the Commission to limit such rescission only to those market-based rate sellers making sales to captive customers in areas where there is a finding of market power.[1142] Duke states that the purpose of section 204 is to ensure the financial viability of franchised public utilities. As a result, prior authorization is appropriate for independent and affiliated power marketers with market-based rate authority who do not intend to assume public service franchise obligations.

996. Duke argues that the Commission has not explained how issuance of a security or assumption of a liability by an affiliated marketer or merchant generator could be contrary to the public interest merely because an affiliate is deemed to have market power in power sales markets in a particular geographic area. Duke asserts that there is no evidence presented in the NOPR that would support the presumed linkage between a determination of a seller's market power in a particular geographic market and the ability of that seller's affiliates to leverage such market power in other geographic markets through their issuances of securities or debt. Duke says that this is especially true in the case of entities such as the Duke affiliates, which have amended their tariffs to preclude market-based rate sales in the Duke Power control area, the only geographic market where the company was determined to have market power. Given that no market-based rate sales will be made by the affiliates in the only geographic area where there was even an issue of market power, Duke states that there is no possible nexus between securities issuances by these entities and protecting the franchised customers of Duke's traditional utility affiliates.

997. Duke concludes that the Commission should determine that blanket authorizations under section 204 for market-based rate sellers should not be affected by a finding that a utility affiliate can exercise market power in its control area or other geographic markets. In the alternative, Duke asks the Commission to determine that, in cases where sellers cannot sell power at market-based rates in the geographic market(s) where an affiliated traditional utility is found to have market power, there can be no anti-competitive effects or need to protect franchise customers, and thus affiliated sellers should be able to obtain (or retain) blanket section 204 authorizations.

Commission Determination

998. We will continue to grant blanket approval under Part 34 for future issuances of securities and assumptions of liability where the entity seeking market-based rate authority, such as a power marketer or power producer, is not a franchised public utility or does not otherwise provide requirements service at cost-based rates.[1143] The Commission traditionally has granted blanket authorization for the issuance of securities and assumptions of liability to power sellers not subject to cost-based rate regulation, *i.e.*, power sellers that have market-based rate authority.[1144] As the Commission has explained in previous cases involving market-based rate authority in which the sellers sought blanket authorization of issuances of securities or assumptions of liability, the purpose of section 204 of the FPA, which Part 34 implements, is to ensure the financial viability of public utilities obligated to serve consumers of electricity.[1145] Accordingly, where the seller is not a franchised public utility providing electric service to customers under cost-based regulation and has market-based rate authority, the Commission's practice is to grant the blanket authorization, subject to consideration of objections by an interested party.

999. We do not adopt the NOPR proposal concerning the rescission of blanket authorizations for affiliates of mitigated sellers. After careful consideration of the comments received, we will limit such rescission to the mitigated seller and its affiliates making sales within the mitigated balancing authority area. Our decision here takes into account Duke's and PPL's arguments against rescission of blanket authorization for all affiliates in all markets. We conclude that it is not necessary to rescind such blanket authorizations in the case of affiliates that make sales outside of the mitigated balancing authority area because the seller retains its market-based rate authority in unmitigated markets. We clarify that the effective date for rescinding blanket authorization under Part 34 will be commensurate with the date on which a mitigated seller begins to sell power at cost-based rates. Further, sellers losing their market-based rate authority must file with the Commission to obtain specific authorization for securities to be issued, or liabilities to be assumed, prior to the date the seller first sells at cost-based rates.

2. Sellers Affiliated With a Foreign Utility

Commission Proposal

1000. Under existing policy, a seller affiliated with a foreign utility selling in the United States (and each of its affiliates) must not have, or must have mitigated, market power in generation and transmission and not control other barriers to entry. In addition, the Commission considers whether there is evidence of affiliate abuse or reciprocal dealing. However, for sellers affiliated with a foreign utility, the Commission has allowed a modified approach to the current four prongs.

1001. With regard to generation market power, should any of the seller's first-tier markets include a United States market, the seller performs the market power screens in that control area(s). With regard to transmission market power, the Commission requires the seller affiliated with a foreign utility seeking market-based rate authority to demonstrate that its transmission-owning affiliate offers non-discriminatory access to its transmission system that can be used by its competitors to reach United States markets. The Commission does not consider transmission and generation facilities that are located exclusively outside of the United States and that are not directly interconnected to the United States. However, the Commission would consider transmission facilities that are exclusively outside the United States but nevertheless interconnected to an affiliate's transmission system that is directly interconnected to the United States. A seller affiliated with a foreign utility must inform the Commission of any potential barriers to entry that can be exercised by either it or its affiliates in the same manner as a seller located within the United States. Regarding affiliate abuse, the requirement that a power marketer with market-based rate authority file for approval under section 205 of the FPA before selling power to a utility affiliate does not apply to situations involving sales of power to a

[1142] Duke supplemental comments at 1–8. *See also* PPL at 26 (loss of any waiver should apply only to the seller or affiliates that make wholesale sales in the control area where market-based rate authority is lost, but not to affiliates that do not conduct business in that control area).

[1143] *See, e.g., Golden Spread Electric Coop., Inc.,* 97 FERC ¶ 61,025 at 61,070 (2001) (''While Golden Spread has been granted market-based rate authority, it also makes requirements sales under Commission-accepted, cost-based rates. Since Golden Spread sells power at cost-based rates and not solely at market-based rates, it fails to qualify for blanket approval to issue securities.'').

[1144] *Merrill Lynch Commodities, Inc.,* 108 FERC ¶ 61,233 at P 16 (2004).

[1145] *Id.* (*citing Citizens Energy Corp.,* 35 FERC ¶ 61,198 at p. 61,455 (1986); *Howell Gas Management Co.,* 40 FERC ¶ 61,336 at p. 62,026 (1987)).

foreign utility outside of the Commission's jurisdiction.

1002. The Commission proposed in the NOPR to retain its current policy when reviewing the application for market-based rate authorization by a seller affiliated with a foreign utility, and sought comment regarding whether the current policy is adequate to grant market-based rate authorization to such sellers. No comments were submitted on the broad question of whether our current policy, in general, is adequate. However, Powerex and NL Hydro [1146] raise specific issues that are addressed below. As discussed below, we conclude that our current approach needs no modification. Accordingly, we will adopt the NOPR proposal to retain our current policy when reviewing an application for market-based rate authority by a seller affiliated with a foreign utility.

Comments

1003. Powerex notes that comparability for non-jurisdictional United States-based transmission providers (''unregulated transmitting utilities'' under the FPA) is now defined by statute to mean service ''at rates that are comparable to those that the unregulated transmitting utility charges itself'' and ''on terms and conditions that are comparable to those under which the unregulated transmitting utility provides transmission services to itself and that are not unduly discriminatory or preferential.'' [1147] Powerex notes that, in the OATT Reform NOPR, the Commission proposed to apply the comparability requirement of FPA section 211A on a case-by-case basis, *i.e.*, by complaint.[1148] Powerex states that, under principles of national treatment as set out in the North American Free Trade Agreement (NAFTA), the Commission should impose no more stringent a burden on similarly non-jurisdictional Canadian and Mexican transmission-owning utilities. For that reason, Powerex urges the Commission to clarify that it will presume that Canadian and Mexican transmitting utilities are providing comparable and not unduly discriminatory or preferential transmission service unless this presumption is otherwise rebutted by third party or Commission-instituted complaint.[1149]

1004. NL Hydro urges the Commission to reject Powerex's suggestion that the Commission no longer should require market-based rate sellers to affirmatively demonstrate that non-discriminatory access is offered on transmission facilities that they or their affiliates own, control, or operate outside of the United States. NL Hydro argues that the comparability standard of FPA section 211A does not govern the Commission's market-based rate analysis of transmission market power.[1150] It states that the Commission has not suggested, in either this proceeding or the OATT rulemaking, that the comparability standard in FPA section 211A should create a presumption that any market-based rate seller (domestic or affiliated with a foreign utility) should be presumed to have passed the transmission market power test.[1151]

1005. NL Hydro supports the Commission's proposal to retain its existing requirements with respect to the mitigation of transmission market power when reviewing the market-based rate applications of sellers affiliated with a foreign utility. According to NL Hydro, these requirements establish a reasonable balance among important regulatory objectives by: (1) Requiring non-discriminatory access to foreign transmission facilities for access to United States markets as a condition of market-based rate authority; (2) complying with the national treatment requirements of NAFTA; and (3) applying principles of comity to the jurisdiction of foreign regulatory authorities with direct regulatory jurisdiction over foreign transmission entities.[1152] Accordingly, NL Hydro believes that the Commission should codify in its regulations the requirement that a market-based rate seller, or its affiliate, that owns, controls, or operates transmission facilities outside of the United States must demonstrate that non-discriminatory access is offered on those facilities so that competitors of the seller may reach United States markets.

Commission Determination

1006. We will continue to require a seller seeking market-based rate authority that is a foreign utility or is affiliated with a foreign utility to affirmatively demonstrate that any owned or affiliated transmission is offered on a non-discriminatory basis that can be used by competitors of the seller or its affiliate to reach United States markets. Accordingly, we reject Powerex's suggestion that the Commission should presume that foreign transmitting utilities are providing comparable and not unduly discriminatory or preferential transmission service unless this presumption is rebutted. The Commission did not propose to implement section 211A of the FPA in Order No. 890 and section 211A is not relevant to the Commission's analysis for purposes of granting or denying market-based rate authority.[1153]

1007. We will codify in § 35.37(d) of the Commission's regulations the requirement that a market-based rate seller affiliated with a foreign utility, or its affiliate, that owns, controls, or operates transmission facilities outside of the United States and is interconnected with the United States must demonstrate that comparable, non-discriminatory access is offered on those facilities so that competitors of the seller may reach United States markets.

3. Change in Status

Commission Proposal

1008. In early 2005, the Commission clarified and standardized market-based rate sellers' reporting requirements for any change in status that departed from the characteristics the Commission relied on in initially authorizing sales at market-based rates. In Order No. 652,[1154] the Commission required, as a condition of obtaining and retaining market-base rate authority, that sellers file notices of such changes no later than 30 days after the change in status occurs. In the NOPR, the Commission sought comment on a number of issues that the Commission identified in Order No. 652 as issues that could be pursued in this proceeding. The Commission solicited comment on whether ownership of any new inputs to electric power production, including fuel supplies, should be reportable. To the extent that any such information is deemed reportable, the Commission proposed to align this reporting requirement to reflect the consideration of other barriers to entry as part of the vertical market power analysis.

1009. The Commission proposed, consistent with Order No. 652, not to require the reporting of transmission outages per se as a change in status. However, to the extent a transmission outage affects on a long-term basis whether the seller satisfies the Commission's concerns regarding horizontal or vertical market power, a change of status filing would be required. The Commission sought comment on this proposal.

[1146] NL Hydro is a Crown Corporation owned by the Government of Newfoundland and Labrador.

[1147] 16 U.S.C. 824j–1(b).

[1148] OATT NOPR at P 111.

[1149] Powerex at 32.

[1150] NL Hydro reply comments at 3.

[1151] *Id.* at 5.

[1152] NL Hydro at 13.

[1153] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 192.

[1154] Order No. 652 at P 47.

The Commission declined in Order No. 652 to narrow or delineate the definition of control. The Commission concluded that it is not possible to predict every contractual agreement that could result in a change of control of an asset; however, the Commission indicated that to the extent that parties wish to propose specific definitions or clarifications to the Commission's historical definition of control, they may do so in the course of the instant rulemaking.[1155]

1010. As proposed in the NOPR (§ 35.43 of the proposed regulations), events that constitute a change in status include the following: First, ownership or control of generation capacity that results in net increases of 100 MW or more, or of transmission facilities, or of inputs to electric power production other than fuel supplies; or, second, affiliation with any entity not disclosed in an application for market-based rate authority that owns, operates, or controls generation or transmission facilities or inputs to electric power production, or affiliation with any entity that has a franchised service area.[1156] The Commission invited comment generally on whether the Commission should expand the triggering events for a change in status filing beyond what was adopted in Order No. 652. In Order No. 652, we concluded that the reporting obligation should extend only to changes in circumstances within the knowledge and control of the seller.

a. Fuel Supplies

Comments

1011. Some commenters in general support the idea that ownership of fuel supplies should not be a factor in the vertical market power analysis and should not trigger a requirement to file a notice of change in status.[1157] APPA/TAPS support the reporting of the acquisition of the means of production or transportation of fuel but not the reporting of the acquisition of fuel itself. APPA/TAPS explain that acquisition or control over companies that produce or deliver fuel and acquisitions of, or affiliations (including through joint ventures) with, production or transportation resources (including LNG facilities) are inputs into electric power production that can raise significant competitive concerns. APPA/TAPS submit that, unlike fuel, the means of production or transportation of fuel are not so readily obtainable from alternative sources.[1158] They argue that while entry from new storage or transportation facilities/transporters is possible, such entry involves sufficient siting difficulties and capital requirements that it cannot be assumed to be timely, likely or sufficient to remove competitive concerns.

1012. Constellation suggests that the Commission should clearly distinguish between fuel supplies (including the capacity to produce and process them) and physical facilities used to transport or distribute fuel supplies. Constellation believes that ownership of fuel supply does not contribute to market power because of the availability of alternative suppliers. Constellation states that, while ownership or control of physical facilities to transport or distribute fuel has the potential to contribute to market power in some cases, such potential generally is blunted by regulation or by the availability of substitutes. Constellation asserts that ownership of facilities for the production or processing of coal or other fuels should not be reportable because alternative sources of supply can substitute for the coal or other fuels that can be produced or processed by such facilities. Constellation states that in specific instances, if any intervenor believes that fuel supplies (or fuel production or processing facilities) are not available from alternative suppliers for delivery in the relevant geographic region, the party could provide appropriate information in an attempt to rebut a market-based rate seller's statement that it cannot erect barriers to entry in relevant markets.[1159]

1013. Constellation believes that the purchase of natural gas transportation or storage on intrastate or interstate pipelines should not trigger any change in status reporting requirement. It states that these transactions do not involve ownership or control of physical facilities for the transportation or storage of natural gas. Moreover, because capacity is available from the natural gas transportation and storage providers themselves, and through capacity release programs from other customers of such providers, Constellation believes that the purchase of such capacity does not contribute to the seller's vertical market power.[1160]

Commission Determination

1014. The Commission will not expand the change in status reporting requirement to include the reporting of a change in ownership or control of natural gas and oil supplies, or affiliation with an entity that owns or controls such fuel supplies. However, we will require the reporting of a change in status with regard to the ownership or control of, or affiliation with, any entity not disclosed in the application for market-based rate authority that owns, or controls ''inputs to electric power production,'' where that term is defined as ''intrastate natural gas transportation, intrastate natural gas storage or distribution facilities; sites for new generation capacity development; sources of coal supplies and the transportation of coal supplies such as barges and railcars.'' The Commission adopts this approach to align the change in status reporting requirement to reflect the other barriers to entry part of the vertical market power analysis.

1015. We will adopt the current change in status requirement with the following modifications.[1161] We will delete the phrase ''other than fuel supplies'' from proposed § 35.43(a)(1) (now § 35.42(a)(1)). We originally proposed that events that constitute a change in status include ''[o]wnership or control of generation capacity that results in net increases of 100 MW or more, or transmission facilities or inputs to electric power production other than fuel supplies.'' In light of the definition of ''inputs to electric power production'' that we adopt in this Final Rule, there is no longer a need in § 35.42(a)(1) for the phrase ''other than fuel supplies.'' As noted above in the discussion on vertical market power, in this Final Rule we modify the definition of ''inputs to electric power production'' to mean ''intrastate natural gas transportation, intrastate natural gas storage or distribution facilities; sites for new generation capacity development; sources of coal supplies and the transportation of coal supplies such as barges and railcars.'' The definition of ''inputs to electric power production'' includes ''sources of coal supplies,'' and therefore, including the phrase ''other than fuel supplies'' would be inaccurate. However, we note that the ownership or control of certain other fuel supplies (*i.e.*, gas and oil supplies) will not require a notice of change in status.

1016. Next, we are modifying the change in status provisions to be consistent with the horizontal and vertical market power provisions which we are adopting. Section 35.42, as adopted herein, differs from the NOPR

[1155] *Id.* at P 47.

[1156] NOPR at P 179–182.

[1157] APPA/TAPS at 90–91; EEI at 21; Constellation at 23.

[1158] APPA/TAPS at 90–91, citing *San Diego Gas & Elec. Co.*, 83 FERC ¶ 61,199 (1998) (gas/electric merger).

[1159] Constellation at 24–25.

[1160] *Id.* at 25.

[1161] Another change to 18 CFR 35.42 is described above in the implementation section.

proposal in that we will require change in status notifications for changes in ownership or control of inputs to electric power production. Additionally, change in status notifications will be required for changes in operation, in addition to ownership and control, of transmission facilities. Similarly, we will require a change in status notification for affiliation with any entity not disclosed in the application for market-based rate authority that owns or controls generation facilities or inputs to electric power production and any entity not disclosed in the application for market-based rate authority that owns, operates or controls transmission facilities.

1017. In response to APPA/TAPS, we clarify that the Commission's change in status requirements are intended to track the requirements embedded in the horizontal and vertical analysis as well as the affiliate abuse representations. As clarified in the other barriers to entry part of the vertical market power analysis described in this Final Rule, the Commission will not require an analysis or affirmative statement with regard to ownership or control of, or affiliation with, an entity that owns or controls natural gas and oil supplies, the interstate transportation of natural gas, or the transportation of oil. In contrast, we will require a seller to provide a description of its ownership or control of, or affiliation with, an entity that owns or controls intrastate natural gas transportation; intrastate natural gas storage or distribution facilities; sites for generation capacity development; and sources of coal supplies and the transportation of coal supplies (defined as ''inputs to electric power production'' in the regulations); however, we adopt a rebuttable presumption that sellers cannot erect barriers to entry with regard to inputs to electric power production. Thus, while a seller is required to describe in a change in status filing any ownership of, control of or affiliation with entities that own or control inputs to electric power production (just as it must do in an initial application for market-based rate authority and an updated market power analysis), we will rebuttably presume that such ownership, control or affiliation does not allow a seller to raise entry barriers. We will, however, allow intervenors to demonstrate otherwise.

1018. Further, in response to Constellation, we note that we presently do not require the reporting of capacity contracted for, but for which control is not transferred, with regard to interstate or intrastate natural gas pipeline or storage capacity and we agree that there is no compelling reason to begin doing so.

b. Transmission Outages

Comments

1019. Numerous commenters support the Commission's current policy and proposal not to require the reporting of transmission outages per se as a change in status.[1162]

1020. Some commenters support the proposal not to require the reporting of all transmission outages per se because they believe that requiring sellers to report all transmission outages as changes in status would prove an overwhelming administrative burden with no market benefits.[1163] Indianapolis P&L states that this approach balances the need for the Commission to have updated information with the need for sellers to focus on their business, rather than administrative filings.[1164] EEI supports the current policy that only long-term transmission outages that could affect the Commission's analysis of vertical and horizontal market power should be reportable.[1165]

1021. APPA/TAPS state that at least some transmission outage information is (or should be) publicly available on OASIS sites, suggesting less of a need to impose a separate reporting requirement for such outages.[1166] However, APPA/TAPS urge that certain outages be reported to the Commission's Office of Enforcement on a non-public basis and that the Commission reserve its authority to require change of status reports for other, significant outages.[1167] We note, however, that APPA/TAPS fail to provide examples of the types of outages that they believe should be reportable.

1022. APPA/TAPS also suggest that the Commission identify for specific market-based rate sellers generation and transmission facilities that, if there is an extended or repeated outage, could produce significant transmission constraints or reductions in the amount of available generation in that seller's market(s). They suggest that the Commission, in conjunction with an RTO/ISO market monitor (where one exists), could identify and designate in that seller's market-based rate authorization the key transmission facilities and/or generation units that are likely to increase competitive concerns if they go out of service. Because of the increased potential for market power harm associated with the outage of these facilities, APPA/TAPS suggest that the Commission could require a market-based rate seller under the terms of its market-based rate authorization to report publicly as a change in status outages of these specified facilities.[1168]

1023. Powerex believes that additional clarification is necessary to determine what the Commission means by ''long-term outages'' that may affect a seller's market power analysis. Powerex also requests that the Commission consider whether transmission outages on a non-jurisdictional or foreign affiliate's transmission system should be considered a change in status that is reportable under Order No. 652, given the limits of the Commission's jurisdictional interests.

Commission Determination

1024. We adopt the NOPR proposal not to require the reporting of transmission outages per se as a change in status. We agree that the reporting of all transmission outages, including the most routine, would be an excessive burden on sellers with no apparent countervailing benefit. However, consistent with Order No. 652, we reiterate that to the extent a long-term transmission outage affects one or more of the factors of the Commission's market-based rate analysis (*e.g.*, if it reduces imports of capacity by competitors that, if reflected in the generation market power screens, would change the results of the screens from a ''pass'' to a ''fail''), a change of status filing is required.[1169]

1025. We reject APPA/TAPS's suggestion that the Commission should require the automatic reporting of some transmission outages to the Office of Enforcement. APPA/TAPS fails to adequately explain why we should assume certain transmission outages are, as a matter of routine, an enforcement matter to be investigated for wrongdoing.

1026. We also reject APPA/TAPS' suggestion that the Commission identify certain generation and transmission facilities that could produce significant transmission constraints or reductions in the amount of generation available in

[1162] APPA/TAPS at 87–89; Indianapolis P&L at 15; EEI at 21; MidAmerican at 35–36; and Powerex at 34.

[1163] MidAmerican at 36; Indianapolis P&L at 15; EEI at 21.

[1164] Indianapolis P&L at 15.

[1165] EEI at 21.

[1166] APPA/TAPS at 88.

[1167] *Id.* at 87–88.

[1168] APPA/TAPS at 88–89.

[1169] In response to Powerex's request for clarification on what the Commission means by ''long-term outages'' that may affect a seller's market power analysis, we clarify that the Commission uses the term ''long-term'' to mean one year or longer.

that market-based rate seller's market(s). Public identification of such generation and transmission facilities could cause CEII and security concerns. In addition, outages that could affect a seller's market-based rate analysis will change over time. The burden remains on the market-based rate seller to identify the outages that should be reported as a change in status. We also remind commenters that entities may file a complaint or call the Office of Enforcement hotline if they are concerned that an outage provides the opportunity for a seller to exercise market power. Regarding Powerex's request that the Commission consider whether transmission outages on a non-jurisdictional or foreign affiliate's transmission system should be considered reportable under Order No. 652, given the limits of the Commission's jurisdictional interests, we clarify that, consistent with our change in status reporting requirement in general, to the extent that a transmission outage reflects a change in the characteristics that the Commission relied on (*e.g.*, if it reduces imports of capacity by competitors that, if reflected in the generation market power screens for U.S. markets, would change the results of the screens from a ''pass'' to a ''fail''), a change of status filing would be required. The change in status requirement is an important element of the Commission's market power oversight. If a seller affiliated with a foreign utility wishes to retain market-based rate authority in the United States, such seller must comply with the notice of change in status requirements, including the reporting of transmission outages that may change the results of the screens from a ''pass'' to a ''fail.'' The Commission finds no reason to exempt a seller affiliated with a foreign utility from this requirement.

c. Control

Comments

1027. Several commenters note that increased precision in the Commission's definition of control would be particularly helpful to sellers, especially in light of the increased emphasis on reporting accuracy and completeness and the Commission's general practice of accepting change in status filings in letter orders, without providing much detailed analysis or explanation as to whether the filings were required in the first place.[1170] These commenters seek clarification that energy contracts that are not associated with a specific resource (do not specify a ''source'') do not transfer control. EEI and SoCal Edison argue that such contracts or liquidated damages call option contracts do not transfer control because, at their core, they are financial transactions used to mitigate the buyer's price risk.[1171] According to commenters, the option holder does not actually control any particular capacity that might be used to meet the contract needs. The energy could come from the seller, from the market through the seller, or directly from the market to the buyer if the seller opts to pay liquidated damages. They submit that if such a contract were deemed to transfer ''control,'' execution of such routine contracts would trigger a change in status filing for each incremental 100 MW purchased thereby, which is most likely not what the Commission intended.

1028. APPA/TAPS support a reporting obligation for all of the types of contractual arrangements that could confer control, as consistent with the discussion in the horizontal market power section of the NOPR. They argue that these arrangements could provide a market-based seller with the means to determine whether capacity is offered into a market and whether a competitor can or will enter a market. They state that these arrangements also create opportunities for sellers to coordinate their behavior with other competitors. If the contracts do not raise competitive concerns, the seller could explain the factors supporting that conclusion in its report.[1172]

1029. SoCal Edison urges the Commission to consider whether, and to clarify how, the emerging, non-traditional capacity and electrical energy products that are routinely transacted in hybrid electricity markets today would fit within its construction of its test for control ('' * * * affecting ability of the capacity to reach the relevant market''). It warns that buyers may be hesitant to routinely purchase products that require continual change in status filings.[1173]

Commission Determination

1030. Pursuant to the change in status reporting requirement, a market-based rate seller is required to report a change in control to the extent the seller acquires a net 100 MW or more generation capacity through contract. Our determination of what constitutes control is discussed above in the horizontal market power analysis section and we adopt that discussion for purposes of the change in status requirement. That is, the Commission concludes that the determination of control is appropriately based on a review of the totality of circumstances on a fact specific basis. No single factor or factors necessarily results in control. If a seller has control over certain capacity such that the seller can affect the ability of the capacity to reach the relevant market, then that capacity should be attributed to the seller for purposes of complying with the change in status requirement.

1031. Further, as the Commission has previously clarified, sellers making a change in status filing to report an energy management agreement are required to make an affirmative statement in their filing as to whether the agreement at issue transfers control of any assets and whether the agreement results in any material effect on the conditions that the Commission relied upon for the grant of market-based rate authority. On some occasions, and at the Commission's discretion, the Commission may request the seller to submit a copy of the agreement and provide supporting documentation.[1174]

1032. We reiterate here that a seller making a change in status filing is required to state whether it has made a filing pursuant to section 203 of the FPA.[1175] To the extent the seller has made a section 203 filing that it submits is being made out of an abundance of caution without conceding that the Commission has section 203 jurisdiction, the seller will be required to incorporate this same assumption in its market-based rate change in status filing (*e.g.*, if the seller assumes that it will control a jurisdictional facility in a section 203 filing, it should make that same assumption in its market-based rate change in status filing and, on that basis, inform the Commission as to whether there is any material effect on its market-based rate authority).[1176]

d. Triggering Events

Comments

1033. In the NOPR, the Commission invited comments on whether it should expand the triggering events for a change in status filing beyond

[1170] EEI at 21–22; SoCal Edison at 10–14; Williams at 1; and Powerex at 33.

[1171] EEI offers an example of a firm energy call option that, in response to a day-ahead call by the buyer, gives the seller the option of delivering energy from its own facilities or buying energy from the competitive market, with the obligation to pay liquidated damages equal to the difference in price between the pre-agreed price and the cost to the buyer of buying replacement power from another source for failure to deliver. EEI argues such contract should not be deemed to transfer ''control'' and therefore should not be reportable.

[1172] APPA/TAPS at 89.

[1173] SoCal Edison at 14–16.

[1174] *Calpine Energy Services, L.P.*, 113 FERC ¶ 61,158 at P 13 (2005) (*Calpine*).

[1175] 16 U.S.C. 824b.

[1176] *Calpine,* 113 FERC ¶61,158 at P 14.

ownership or control of facilities or inputs and affiliation with entities that own or control facilities or inputs or that have a franchised service territory, as set forth in Order No. 652. No commenters suggest additional triggering events, and several commenters oppose any general expansion of categories.[1177] Several commenters specifically oppose any requirement to report actions taken by competitors or natural events as a change in status. They argue that, in many cases, the seller may be unaware of actions taken by a competitor, making compliance virtually impossible.[1178]

Commission Determination

1034. We will not expand the events that trigger a change in status filing. Further, we will not expand triggering events to include actions taken by a competitor (such as a decision to retire a generation unit or take transmission capacity out of service) or natural events (such as hydro-year level, higher wind generation, or load disruptions due to adverse weather conditions) beyond those adopted in Order No. 652. As we describe above in the vertical market power analysis discussion, with regard to barriers to entry erected or controlled by other than the seller, we find that it is not reasonable to routinely require sellers to make a showing regarding potential barriers to entry that others might erect and that are beyond the seller's control. However, we will entertain on a case-by-case basis claims that the existence of barriers to entry beyond the seller's control may affect the seller's ability to exercise market power. For similar reasons we will not expand the events that trigger a change in status filing to include actions taken by a competitor or natural events. However, we will entertain on a case-by-case basis claims that such actions may affect the seller's ability to exercise market power.

e. Timing of Reporting

Comments

1035. At present, the Commission requires the reporting of changes in status to be ''filed no later than 30 days after the legal or effective date of the change in status, including a change in ownership or control, whichever is earlier.'' [1179] The proposed regulatory text maintains this requirement.

1036. CAISO supports the current requirement that entities with market-based rate authority must report changes of status no later than 30 days after the change has occurred. CAISO proposes that any change in status be reported not only to the Commission but also to the relevant market monitor where the facilities are located. CAISO states that this minimal additional burden on the supplier will ensure that RTO and ISO staff are operating with the latest possible information.[1180]

1037. SoCal Edison recommends that the Commission revise the change in status reporting requirement to focus upon the actual acquisition of the resources in question—for power sales contracts, the date of physical power delivery. SoCal Edison states that the Commission's current policies make it virtually impossible for a seller to provide a meaningful evaluation of whether or not a forward contract with delivery months or years in the future creates a departure from the characteristics the Commission relied upon in granting market-based rate authority as much as three years previously. SoCal Edison notes that, as currently written, the policy requires reporting of procurement activities potentially years in advance of any power delivery because the effective date of the contract—usually the execution date—may significantly precede the date of physical delivery—that is, the actual transfer of control over generation resources.[1181]

Commission Determination

1038. We provide clarification regarding when a change in status filing should be filed. In Order No. 652, we determined that reports of changes in status must be filed no later than 30 days after the legal or effective date of the change in status, including a change in ownership or control, whichever is earlier.[1182] However, it was not the Commission's intention, as SoCal Edison notes, to require reporting of procurement activities potentially years in advance of any power delivery. We agree with SoCal Edison that the current policy may be unclear and may cause an entity to file a notice of change in status years in advance of the actual transaction, *i.e.*, change in ownership or transfer of control. The Commission requires a meaningful evaluation of whether a change creates a departure from the characteristics the Commission relied upon in granting market-based rate authority. It would be difficult for the Commission to accurately evaluate whether or not, for example, a forward contract with delivery months or years in the future will affect the conditions the Commission relied upon for the market-based rate authorization. Accordingly, we will modify § 35.42(b) (formerly § 35.43(b)) to provide that, in the case of power sales contracts with future delivery, such contracts are reportable 30 days after the physical delivery has begun.

1039. We reject CAISO's proposal that any change in status also be reported to the relevant market monitor where the facilities are located. We find that informing the Commission of changes in status is sufficient. Change in status filings are noticed and therefore interested entities will have notice of any such filing.

f. Sellers Affiliated With a Foreign Utility

1040. The change in status requirement is applicable to all market-based rate sellers regardless whether they are domestic or affiliated with a foreign utility.

Comments

1041. Powerex notes that the Commission stated in the NOPR that it ''does not consider transmission and generation facilities that are located exclusively out of the United States and that are not directly interconnected to the United States [but] would consider transmission facilities that are exclusively outside the United States but nevertheless interconnected to an affiliate's transmission system that is directly interconnected to the United States.'' [1183] Powerex submits that the NOPR fails to clarify the Commission's proposed treatment of foreign-sited generation facilities interconnected to an affiliated transmission system that, in turn, is directly interconnected to the United States transmission grid. Powerex argues that, based on the nature of the Commission's concerns with respect to facilities outside the United States, the details concerning such generation capacity should not be relevant to the Commission's determination in circumstances where the affiliated uncommitted capacity exceeds the transmission limits of the intertie(s) directly interconnecting the affiliated foreign transmission system to the United States grid. Powerex states that foreign sellers with foreign generating facilities can make that generation available to United States

[1177] MidAmerican at 36; Powerex at 34.

[1178] MidAmerican at 36–37; Powerex at 34.

[1179] Order No. 652 at P 106. The Commission clarified that for power sales contracts, ''it is irrelevant for the purposes of compliance with the reporting obligation if the effective date on which control is transferred occurs prior to the date on which the purchaser is contractually bound to commence physical delivery.'' Order No. 652–A at P 31.

[1180] CAISO at 15.

[1181] SoCal Edison at 17–19.

[1182] Order No. 652 at 106.

[1183] NOPR at P 175.

markets only to the extent that transmission capacity is available on the interties crossing the international boundaries. In such instances, Powerex argues that the seller's participation in United States jurisdictional markets is constrained by the total transfer capability (TTC) of the transmission system of the intertie (a measurement of the level of imports that can access a market from a particular location). Powerex asserts that those intertie limits represent the foreign seller's maximum uncommitted foreign capacity available to United States markets.[1184] Thus, according to Powerex, only changes in the TTC of the intertie itself should be considered a change in the circumstances upon which the original market-based rate authorization was based, for purposes of Order No. 652 filings.[1185]

1042. Powerex also argues that complying with the change in status requirements of Order No. 652 would require foreign sellers to demand routine updates of potentially non-public information from their foreign generation-owning affiliates; it contends that Order No. 652 imposes a continuous updating requirement any time an affiliate acquires additional generation assets, re-rates an existing facility, or enters into third-party contracts that confer some degree of control.[1186] Powerex states that in certain circumstances, release of information could be inconsistent with the standards and policies of the foreign utility regulatory agency regulating the foreign generation owner.[1187] Powerex argues that concerns related to these types of frequently non-public changes to an affiliate's generation profile are appropriately limited to United States assets located in United States markets.

Commission Determination

1043. The Commission treats foreign-sited generation facilities interconnected to an affiliated transmission system that, in turn, is directly interconnected to the United States transmission grid in the same way that it treats the first-tier generation facilities of non-foreign sellers. For the purpose of determining total uncommitted capacity, the affiliates' capacity is combined.

1044. In response to Powerex, we agree that if the Commission's grant of market-based rate authority was based on the seller's, including its affiliate's, uncommitted capacity exceeding the transmission limits of the intertie(s) directly interconnecting the seller to the United States grid, only changes in the TTC of the intertie would be considered a change in status subject to a reporting requirement.

1045. Further, if a foreign utility believes that release of specific information is inconsistent with the policies of a foreign utility regulatory agency, the foreign utility should specifically inform the Commission of this, and the Commission will take the matter under advisement when considering whether to grant a request for special treatment.

4. Third-Party Providers of Ancillary Services

Commission Proposal

1046. In Order No. 888, the Commission required transmission providers to offer certain ancillary services at cost-based rates as part of their open access commitment but also contemplated that third parties (parties other than the transmission provider in a particular transaction) could provide certain ancillary services.[1188] The Commission also left open the door for ancillary services to be provided on other than a cost-of-service basis. In Order No. 888, the Commission stated that it would entertain requests for market-based pricing related to ancillary services on a case-by-case basis if supported by analyses that demonstrate that the seller lacks market power in these discrete services.[1189]

1047. In *Ocean Vista Power Generation, L.L.C.*,[1190] the Commission explained that, as a general matter, a study of ancillary service markets should address the nature and characteristics of each ancillary service, as well as the nature and characteristics of generation capable of supplying each service, and that the study should develop market shares for each service. In particular, the Commission stated that an individual seller's market power analysis for ancillary services markets should: (1) Define the relevant product market for each ancillary service; (2) identify the relevant geographic market, which could include all potential sellers of the product from whom the buyer could obtain the service, taking into account relevant factors which may include the other sellers' locations, the physical capability of the delivery system and the cost of such delivery, and important technical characteristics of the sellers' facilities; (3) establish market shares for all suppliers of the ancillary services in the relevant geographic markets; and (4) examine other barriers to entry. The Commission also noted that it would entertain alternative explanations and approaches.

1048. The Commission adopted in *Avista Corporation*[1191] a general policy stating that third-party ancillary service providers that could not perform a market power study would be allowed to sell ancillary services at market-based rates, but only in conjunction with a requirement that such third parties establish an Internet-based OASIS-like site for providing information about and transacting ancillary services. The authorization in *Avista* extended only to the following four ancillary services: Regulation Service, Energy Imbalance Service, Spinning Reserves, and Supplemental Reserves. The Commission based its *Avista* policy on the expectation that, as entry into ancillary service markets occurs, prices will decrease from the level established by the transmission provider's cost-based rate. Under these circumstances, customers will pay prices for ancillary services that are no higher than and will very likely be lower than the transmission provider's cost-based rate. The Commission explained that the ancillary services customer is protected in part by the availability of the same ancillary services at cost-based rates from the transmission provider. The backstop of cost-based ancillary services from the transmission provider provides, in effect, a limit on the price at which customers are willing to buy ancillary services.[1192]

1049. To further monitor market entry, the Commission required third-party suppliers to file with the Commission one year after their Internet-based site was operational (and at least every three years thereafter) a report detailing their activities in the ancillary services market.[1193]

1050. The Commission stated that it would apply this policy only to sellers that are authorized to sell power and energy at market-based rates. In addition, the Commission stated that it

[1184] Powerex at 29–30.

[1185] *Id.* at 30.

[1186] *Id.* at 31.

[1187] Powerex at 31.

[1188] *See* Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,720–21.

[1189] *Id.*; Order No. 888–A, FERC Stats. & Regs. ¶ 31,048 at 30,237–38.

[1190] 82 FERC ¶ 61,114 at 61,406–07 (*Ocean Vista*).

[1191] 87 FERC ¶ 61,223, *order on reh'g,* 89 FERC ¶ 61,136 (1999) (*Avista*).

[1192] We note that the Commission has authorized several utilities to use market index pricing for energy imbalance service. *See, e.g., PacifiCorp,* 95 FERC ¶ 61,145 (2001), *order on reh'g,* 95 FERC ¶ 61,467 (2001). In such a case, customers are protected by the transmission provider's obligation to offer the service at rates the Commission determines are just and reasonable and consistent with our *Avista* policy.

[1193] The Commission subsequently established an EQR requirement for all market-based rate sellers.

would not apply this approach to sales of ancillary services by a third-party supplier in the following situations: (1) Sales to an RTO or an ISO, *i.e.*, where that entity has no ability to self-supply ancillary services but instead depends on third parties;[1194] (2) to address affiliate abuse concerns, sales to a traditional, franchised public utility affiliated with the third-party supplier, or sales where the underlying transmission service is on the system of the public utility affiliated with the third-party supplier; and (3) sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers.[1195]

1051. In the NOPR, the Commission proposed to retain the *Avista* policy but sought comment on whether to modify or revise that current approach and, if so, how. The Commission also sought comment on whether its current conditions, such as the requirement to establish an Internet-based site, continue to be necessary.

a. Internet Postings and Reporting Requirements

Comments

1052. A number of commenters support modifications to the Commission's current approach to third-party sales of ancillary services on the basis that they believe the current policy has not succeeded in engendering robust markets for ancillary services. Avista, Puget, Cogentrix and Powerex state that the existing Internet posting and reporting policy is unnecessary.[1196] Avista and Puget note that the current EQR requirement, which did not exist when the Commission first adopted the Internet posting requirement, provides sufficient information for the Commission to monitor ancillary services markets for market power. They argue that abandoning the Internet posting and reporting conditions would contribute to the development of more robust reserves markets. Similarly, Cogentrix and Powerex maintain that those requirements are burdensome and hard to implement, especially for independent sellers that are not transmission owners and do not have the responsibility to maintain an OASIS. Instead of safeguarding against possible abuses of market power, these commenters state that the posting and reporting requirements have probably hindered the development of robust markets for ancillary services.

1053. Puget states that virtually all ancillary services outside of RTO/ISO markets are provided at cost-based rates by the host transmission provider. Puget states that it conducted a review of the reports filed in dockets in which the Commission has granted market-based rate authority to sell ancillary services under the *Avista* provisions, which revealed that only a handful of ancillary services sales have been made. Based on the small number of market-based ancillary services sales that Puget found in its review of existing dockets, it concludes that companies have determined that the potential commercial gains from entering this market do not justify the cost and risks associated with the special posting and reporting requirements.

1054. Avista and Powerex state that, to the extent that the Commission is concerned about market power, purchasers of ancillary services are protected from the exercise of market power because they may purchase these services from the transmission provider at cost pursuant to the OATT. Powerex maintains that the Commission can monitor these transactions via the EQRs and can encourage purchasers to file complaints under FPA section 206 should they believe a seller has exercised market power when making such sales.

1055. In contrast, APPA/TAPS urge the Commission not to relax standards for market-based pricing of ancillary services. They support continuation of the Commission's current approach for pricing ancillary services, including the requirement for a cost-based backstop for ancillary services provided by a transmission provider. They argue that ancillary services markets remain very much dependent upon control area operation and are closely connected to the operations of the transmission system. APPA/TAPS state that locational reserves requirements limit the geographic scope of potential ancillary service suppliers, and that capacity on automatic generation control cannot easily sell regulation service in its home market today and switch to sales in an adjoining market tomorrow. Further, they state that customers cannot shop for such services. According to APPA/TAPS, limitations of transmission and technology counsel against adopting short-cuts for assessing the appropriateness of market-based pricing of ancillary services.[1197]

1056. Morgan Stanley supports efforts to establish market-based ancillary service markets both inside and outside of ISOs and RTOs. Morgan Stanley recommends that the Commission investigate what is necessary to establish local ancillary services markets on a nationwide basis. Morgan Stanley supports eliminating barriers to entry in the ancillary services market and states that to further this goal, the Commission should allow market participants to negotiate over-the-counter (OTC) ancillary services contracts outside of established ISOs and RTOs. Morgan Stanley mentions that this option should be open to all sellers with market-based rates and that the posting requirement should remain mandatory for mitigated entities.

Commission Determination

1057. We will modify our current approach for third-party sellers of ancillary services at market-based rates as announced in *Avista*. We appreciate the concerns raised by a number of commenters that the posting and reporting requirements imposed in *Avista* may be hindering the development of ancillary services markets particularly by third-party providers. As noted above, some commenters have indicated that the costs and responsibilities associated with establishing and maintaining an internet-based site may outweigh the benefits that third-party sellers could derive from the sale of the additional products. We conclude that our EQR filing requirement provides an adequate means to monitor ancillary services sales by third parties such that the posting and reporting requirements established in *Avista* are no longer necessary. Through their EQR filings, third-party providers of ancillary services provide information regarding their ancillary services transactions for the quarter, including the ancillary service provided, the price, and the purchaser. As a result, we will no longer require third-party providers of

[1194] With the formation of RTOs and ISOs, several RTOs/ISOs performed market analyses to demonstrate whether various ancillary services are competitive. The result has been as follows: California Independent System Operator: Regulation, Spinning Reserve, and Non-Spinning Reserve. ISO New England: Regulation and Frequency (Automatic Generation Control), Operating Reserve—Ten-Minute Spinning, Operating Reserve—Ten-Minute Non-Spinning, and Operating Reserve—Thirty Minute. New York Independent System Operator: Regulation and Frequency Response Service, Operating Reserve Service (including Spinning Reserve, 10-Minute Non-Synchronized Reserves and 30-Minute Reserves). PJM Independent System Operator: Regulation and Frequency Response, Energy Imbalance, Operating Reserve—Spinning, and Operating Reserve—Supplemental. Thus, in markets where the demonstration has been made, sellers are afforded the opportunity to sell at market-based rates subject to any other conditions in those markets.

[1195] *Avista,* 87 FERC at 61,883, n.12.

[1196] Avista at 7–8; Puget at 1, 4–8; Cogentrix at 8–10; Powerex at 35–38; Morgan Stanley at 11–12.

[1197] APPA/TAPS at 91.

ancillary services to establish and maintain an internet-based OASIS-like site for providing information about their ancillary services transactions.

1058. In addition, we will no longer require third-party suppliers to file with the Commission one year after their internet-based site is operational (and at least every three years thereafter) a report detailing their activities in the ancillary services market. We note that the Commission retains the ability to require such a report by a third-party supplier of ancillary services at any time.

1059. All sellers that seek authority to sell ancillary services at market-based rates pursuant to *Avista* [1198] must make a filing with the Commission to request that authority and must include language in their market-based rate tariffs identifying the ancillary services that they offer.[1199]

1060. Moreover, we will retain our current policy of not allowing sales of ancillary services by a third-party supplier in the following situations: (1) Sales to an RTO or an ISO, *i.e.*, where that entity has no ability to self-supply ancillary services but instead depends on third parties; (2) sales to a traditional, franchised public utility affiliated with the third-party supplier, or sales where the underlying transmission service is on the system of the public utility affiliated with the third-party supplier; and (3) sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers.[1200] These standard applicable tariff provisions appear in Appendix C to this Final Rule. As we stated in *Avista,* we are open to considering requests for market-based rate authorization to make such sales on a case-by-case basis.

1061. At this time, the Commission will not adopt Morgan Stanley's recommendation to investigate what is necessary to establish local ancillary services markets on a nationwide basis. We believe that the elimination of certain reporting requirements for third party providers of ancillary services adopted herein will adequately balance the need to encourage the development of ancillary services markets and the Commission's responsibility to provide oversight and protection from market power. We find Morgan Stanley's suggestion that the Commission allow market participants to negotiate OTC ancillary services contracts outside of established RTO/ISO markets unsupported and lacking in detail.[1201]

b. Pricing for Ancillary Services in RTOs/ISOs

Comments

1062. As noted above, the Commission stated in Order No. 888 that it would entertain requests for market-based pricing related to ancillary services on a case-by-case basis if supported by analyses which demonstrate that the seller lacks market power in these discrete services.[1202] To date, the Commission has permitted market-based rate pricing for certain ancillary services in a number of RTOs and ISOs.[1203] Although Ameren supports retaining the Commission's current approach, Ameren urges the Commission to address what it describes as a critical market design flaw regarding pricing for ancillary services in RTO/ISO markets with Day 2 energy markets but no market for ancillary services, such as the Midwest ISO. Ameren explains that providing regulation service and spinning reserves in the Midwest ISO market at traditional cost-based rates is uneconomic at present because owners of ancillary services capacity generally find it more profitable to sell energy from the capacity at market-based rates rather than to offer the capacity as reserves at cost-based rates. Ameren recommends that the Commission ensure that its approach to sales of ancillary services provides flexibility by allowing sellers for cost-based rates for regulation service and spinning reserves in the Midwest ISO footprint to propose a component for recovery of lost opportunity costs where such costs are shown to be legitimate and verifiable. Ameren submits that the Commission has recognized the need for opportunity cost recovery in other circumstances, and should consider an opportunity cost component in the future.[1204]

1063. CAISO states that it agrees with the Commission's decision to distinguish sales within an RTO or ISO from those not within an RTO or ISO.[1205] It agrees that the Commission can rely on the market monitoring unit of the RTO or ISO to assess competitiveness in the RTO or ISO's ancillary service markets.[1206]

1064. However, CAISO also notes that the size of the ancillary service market is subject to change based on system conditions and the need to meet applicable reliability criteria. It says that at times the CAISO may be able to procure ancillary services on a system-wide basis, whereas at other times factors such as the proportionate mix of hydro and thermal resources, transmission path operating transfer capability limits or deratings, forecasted path flows, anticipated load and weather conditions, and generator outages may require the CAISO to procure ancillary services on a zonal or even more location-specific basis. CAISO also states that because not every facility has the capability to provide every ancillary service, the market power analysis for the energy market does not automatically ensure that market power cannot be exercised with respect to sales of ancillary services. Accordingly, CAISO states that there may be the need for more targeted market power mitigation procedures specifically applicable to sales of ancillary services.

1065. NYISO supports the Commission's proposed approach to the extent it is predicated on all eligible sellers being able to benefit from the Commission's authorization of the NYISO to purchase ancillary services for loads at market-based rates.[1207] It states that all eligible sellers should receive the market-clearing prices for ancillary services that are supplied on a market basis and that the final regulations should not impose burdensome and duplicative market data requirements on a potential seller of ancillary services, either directly or through data demands to an ISO if the ISO has already received

[1198] As noted above, the *Avista* policy applies to the following four ancillary services: Regulation Service, Energy Imbalance Service, Spinning Reserves, and Supplemental Reserves.

[1199] Sellers that have been granted authority to provide third-party ancillary services need not reapply because their authority continues.

[1200] *Avista,* 87 FERC at 61,883, n. 12.

[1201] Morgan Stanley's comments provide an insufficient basis for us to determine whether such OTC ancillary services contracts would be jurisdictional. The Commission has previously stated that it is not concerned with management transactions (such as swaps, options, and futures contracts) designed to assist buyers and sellers of electricity in hedging against adverse price changes which are settled in cash and where parties do not take actual delivery of the electricity. *Morgan Stanley Capital Group, Inc.,* 69 FERC ¶ 61,175 (1994).

[1202] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,656–57; Order No. 888–A, FERC Stats. & Regs. ¶ 31,048 at 30,230.

[1203] *AES Redondo Beach, L.L.C., et al.,* 85 FERC ¶ 61,123 (1998), *order on reh'g,* 87 FERC ¶ 61,208 (1999), *order on reh'g and clarification,* 90 FERC ¶ 61,036 (2000); *New England Power Pool,* 85 FERC ¶ 61,379 (1998), *reh'g denied,* 95 FERC ¶ 61,074 (2001); *Central Hudson Gas & Electric Corporation, et al.,* 86 FERC ¶ 61,062, *order on reh'g,* 88 FERC ¶ 61,138 (1999).

[1204] Ameren at 24–25, citing *San Diego Gas & Elec. Co.,* 95 FERC ¶ 61,115 at 61,363–64 & n.47 (2001).

[1205] CAISO at 16–18.

[1206] CAISO recommends that the Final Rule emphasize the importance of appropriate RTO or ISO market power mitigation tariff provisions for sales involving ancillary services.

[1207] NYISO at 10.

Commission authorization for market-based ancillary services.

1066. APPA/TAPS urge caution for market-based pricing of ancillary services in RTO/ISO areas. Even if the Commission finds that conditions exist to permit market-based pricing of some ancillary services in some RTO/ISO-administered markets, APPA/TAPS state that such pricing would not be appropriate where vertically integrated utilities are also control area operators, such as in Midwest ISO and SPP, because the locational, control-area dependent nature of ancillary services increases the risk that control area operators will have market power.[1208]

1067. Powerex recognizes that in some control areas, there are locational reserve requirements that can be met by a limited number of resources and therefore limit the geographic scope of potential suppliers.[1209] Powerex believes, however, that this situation can be mitigated on a case-specific basis, and therefore that it should not be the basis for generally rejecting the benefits of competitive supply of ancillary services. Powerex believes that it is the combination of the Commission's existing regulatory framework and administrative barriers raised by transmission providers that has effectively stifled the incentives for third-party suppliers to participate in ancillary services markets.[1210] In support, Powerex states that experience with the California organized markets demonstrates that a third-party provider can sell operating reserves and regulation service services to an adjoining market and that these services can be provided from resources located two markets and more than a thousand transmission miles away.

Commission Determination

1068. We will continue our current approach regarding market-based pricing for certain ancillary services in RTOs and ISOs. Where an RTO or ISO performs a market analysis demonstrating a lack of market power for certain ancillary services, the Commission has approved the sale of those ancillary services at market-based rates. As reflected in the NOPR, the Commission has approved the sale of certain ancillary services at market-based rates in CAISO, ISO New England, NYISO, and PJM. Moreover, the Commission considers on a case-by-case basis market power mitigation measures for sales involving ancillary services in these markets.

[1208] APPA/TAPS at 92.

[1209] *See, e.g.*, APPA/TAPS at 90–92.

[1210] Powerex reply comments at 1–3.

1069. Ameren's request that the Commission address what Ameren considers to be a critical market design flaw regarding pricing for ancillary services in the Midwest ISO is beyond the scope of this rulemaking proceeding. Ameren's concerns are more appropriately addressed upon an appropriate record in the context of proceedings involving the Midwest ISO market.

1070. With regard to APPA/TAPS' concern that market-based pricing of ancillary services would not be appropriate where vertically integrated utilities are also balancing authority area operators, such as in Midwest ISO and SPP, we note that the Commission carefully analyzes ancillary service markets in ISOs and RTOs before authorizing market-based rate pricing, ensuring that protections, such as market monitors, are established to reduce the risk that market power can be exercised. APPA/TAPS has had the opportunity to intervene and participate in such proceedings, including in proceedings involving Midwest ISO and SPP.

1071. The Commission also imposes mitigation where necessary. For example, the Commission in its *PJM West/South Regulation Zone* order permitted sellers that lack market power in PJM to submit market-based rate bids in the market for regulation service, while mitigating bids submitted by American Electric Power Company and Virginia Electric and Power Company, because PJM has not sufficiently demonstrated that they lack the potential to exercise market power in this market.[1211]

5. Reactive Power and Real Power Losses

Commission Proposal

1072. In the NOPR, the Commission did not provide a proposal with regard to the treatment of reactive power and real power losses. However, several commenters submitted comments about these services.

[1211] *PJM Interconnection, L.L.C.*, 111 FERC ¶ 61,134 (2005) (*PJM West/South Regulation Zone*). Similarly, the Commission in *New York Independent System Operator, Inc.*, 91 FERC ¶ 61,218 at 61,798–802(2000), suspended market-based pricing in the non-spinning reserve market for a temporary period. The Commission imposed bidding restrictions on 10 minute non-spinning operating reserves suppliers and a mandatory bid requirement which required that all available capacity held by eastern suppliers of 10 minute non-spinning reserves, and that is not subject to a *bona fide* outage or conflicting contractual obligation, be bid into the market. The Commission indicated that the mandatory bid requirement was necessary to protect against the physical withholding of capacity for the 10 minute non-spinning reserve market.

a. Reactive Power

Comments

1073. Cogentrix asks the Commission to reconsider the existing requirements for the sale of reactive power by independent generators. It notes that currently generators can sell reactive power only upon the submission to the Commission of separate cost filings. Cogentrix submits that the requirement of cost justification of reactive power rates should be eliminated. Cogentrix states that this requirement is unnecessary because generators with market-based rate authority are found to lack market power and are subject to the EQR and change in status reporting requirements, which ensure that they continue to lack market power and, therefore, that they cannot dictate the pricing of reactive power services. Cogentrix submits that because reactive power is a service that purchasers require generators to provide, it should be left to the parties to negotiate the proper rate under the interconnection agreement or the power purchase agreement, without requiring the generator to submit additional cost filings.[1212]

Commission Determination

1074. We reject Cogentrix's proposal that the Commission reconsider in this proceeding existing requirements for the sale of reactive power by independent generators and eliminate the requirement that generators submit separate cost filings supporting reactive power sales. Consistent with our precedent,[1213] we will continue to analyze reactive power sales on a case-by-case basis.

b. Real Power Losses

Comments

1075. Powerex requests that the Commission explicitly permit sellers to offer third-party loss compensation services [1214] on non-affiliated transmission systems under their general market-based rate authority.[1215] Powerex states that it believes that third parties currently are making real power losses sales pursuant to their market-

[1212] Cogentrix at 10.

[1213] *See, e.g.*, *Calpine Oneta Power, L.P*, 119 FERC ¶ 61,177 (2007), and cases cited therein.

[1214] Although Powerex does not directly define loss compensation energy, we interpret it to be equivalent to real power losses associated with all transmission service. The Commission's *pro forma* OATT in Order No. 890, sections 15.7 and 28.5, refer to real power losses. For purposes of this Final Rule, we will refer to loss compensation service or energy as real power losses.

[1215] Powerex initial comments at 38–40.

based rate authority.[1216] Powerex believes that the provision of real power losses is no different than the provision of other energy. It notes that in some control areas, the provision of such services comes with other attendant duties such as acting as the scheduling party for the losses.

Commission Determination

1076. We agree with Powerex that the provision of real power losses is no different than the provision of other energy. We clarify that we permit sellers to offer third-party real power losses on non-affiliated transmission systems under their market-based rate authority.

**V. Section-by-Section Analysis of Regulations**

*1. Section 35.27 Authority of State Commissions*

1077. In the NOPR, we explained that the first two paragraphs of this section were added by Order No. 888, while Order No. 652 later added subsection (c) to implement the change in status reporting requirement. The Commission proposed to move or delete subsections (a) and (c), leaving only (b), which clarifies that nothing in this part should be construed as preempting or affecting the authority of State commissions. The NOPR did not propose to revise the language of subsection (b) in any way, and proposed only to amend the heading from ''Power Sales at Market-Based Rates'' to ''Authority of State Commissions.'' NASUCA filed comments in support of ''assuring that there will be no preemption of State prerogatives under the proposed new regulations * * *.'' [1217]

1078. We reiterate that the Commission is not proposing to add or revise this provision at this time. It remains unchanged from when the Commission adopted it in Order No. 888. The fact that it is renumbered in this proceeding will not have any impact, positive or negative, on the prerogatives of State commissions.

[1216] Powerex cites to a filing in which Ameren stated its understanding that it ''may sell the energy that will be used by customers that choose to self-supply energy to meet their transmission losses to such customers under its general market-based power sales authority. [Ameren] will merely be selling the power the customer will use to meet its losses and obligations and, from [Ameren's] standpoint, this will be no different than any other power sale. Such sales are also consistent with the Commission's decision to treat the provision of losses as a service that can be provided by multiple entities, rather than one that the transmission provider is uniquely situated to provide.'' Powerex at 39, citing Letter Transmitting Compliance Filing, Ameren Energy Marketing Co., Docket No. ER01–1945, at n.3 (July 27, 2001).

[1217] NASUCA at 3–4.

*2. Section 35.36 Generally*

1079. This section defines certain terms specific to Subpart H and explains the applicability of Subpart H. Some of these terms were put in place when the Commission codified certain market behavior rules in Order No. 674.[1218]

1080. The NOPR proposed to define ''Seller'' in paragraph (a)(1) as a public utility with authority to, or seeking authority to, engage in sales for resale of electric energy at market-based rates in order to make clear that Subpart H deals exclusively with market-based rate power sales. NASUCA comments that the explanation for the definition of ''Seller'' does not mention any language in FPA section 205 regarding ''market-based rates,'' and further, that there is no reference to market-based rates in that section of the Act. Thus, NASUCA contends that ''the reference in the definition of ''seller'' to ''market-based rates under section 205 of the Federal Power Act'' is a *non sequitur*, lacks support in the statutory language, and should be deleted.'' [1219]

1081. We do not agree that the limiting language should be deleted. We believe that it is essential that the regulations in subpart H apply only to the specific sales that we are regulating herein (*i.e.*, market-based rates for wholesale sales of electric energy, capacity and ancillary services by public utilities) and not to any sales made at cost-based rates or under any other authority; the definition should make this scope clear. To the extent that NASUCA is challenging the Commission's ability to authorize market-based rates at all, the Commission addresses NASUCA's arguments in that regard in the legal authority section of this Final Rule.

1082. In the NOPR, the Commission proposed definitions for Category 1 Sellers and Category 2 Sellers to assist in understanding the parameters of the updated market power analysis filing requirement. The definition of Category 1 Sellers is being clarified, consistent with the discussion above in Implementation Process.

1083. Paragraph (a)(4) defines inputs to electric power production in order to simplify § 35.37(e) regarding other barriers to entry. The Final Rule revises the definition consistent with the discussion in the vertical market power section.

1084. Paragraph (a)(5) indicates that where the term franchised public utility is used, it is meant to include only those public utilities with a franchised service obligation under State law. The Commission modifies the definition as proposed in the NOPR so that the term ''franchised public utility'' does not include only utilities with captive customers. Instead, throughout the final regulations, references to franchised public utilities with captive customers are explicitly identified, where applicable.

1085. New paragraph (a)(6) provides a definition of captive customers, the genesis of which is discussed above in the Affiliate Abuse section.

1086. Paragraph (a)(7) (which was proposed as § 35.36(a)(6) in the NOPR) provides a definition for market-regulated affiliated entities.

1087. New paragraph (a)(8) provides a definition of market information.

1088. Paragraph (b) is a basic description of the applicability of Subpart H.

*3. Section 35.37 Market Power Analysis Required*

1089. This section describes the market power analysis the Commission employs, as discussed in the preamble, and when sellers must file one. It is intended to identify the key aspects of the analysis.

1090. The Final Rule adds paragraph (a)(2), which codifies the requirement mentioned in the NOPR for each seller to include an appendix identifying specified assets with each market power analysis filed. The paragraph also directs readers to Appendix B for a sample asset appendix.

1091. New language in paragaphs (c)(2) and (c)(3) clarifies that both sellers and intervenors may file alternative evidence to support or rebut the indicative screens, and addresses the use of the Delivered Price Test and its role in the analysis of market power, respectively. Further, at paragraph (c)(4), the regulations codify the requirement that each seller use a standard format for the indicative screens, the use of which was proposed in the NOPR.

1092. Paragraph (d) specifies the requirement that a seller with transmission facilities must have on file an Open Access Transmission Tariff. The Final Rule adds a description of how this requirement applies to sellers affiliated with foreign utilities.

1093. Paragraph (e) describes the information that must be provided to demonstrate a lack of vertical market power. The text is revised in several respects reflecting the discussion in the section of the Final Rule on vertical market power.

[1218] *Conditions for Public Utility Market-Based Rate Authorization Holders*, Order No. 674, FERC Stats. & Regs. ¶ 31,208, 114 FERC ¶ 61,163 (2006).

[1219] NASUCA at 32.

1094. The Final Rule adds a new paragraph (f) to address concerns that CEII claims in market-based rate filings have been overbroad. The subsection provides a process for intervenors to gain access to data for which the filer has claimed privileged treatment under 18 CFR 388.112.

*4. Section 35.38 Mitigation*

1095. The regulatory text proposed in the NOPR did not propose specific changes to the current approach to mitigation, and intended to capture the Commission's existing requirements. The Final Rule does not depart from this approach, and adopts the same regulatory text regarding mitigation as proposed in the NOPR, with the addition of a clarification that mitigation will apply only to the market or markets in which a seller is found, or presumed, to have market power.

*5. Section 35.39 Affiliate Restrictions*

1096. This section governs affiliate transactions and affiliate relationships and establishes certain conditions that a seller must satisfy as a condition of its market-based rate authority. New paragraph (a) explains that, as a condition of obtaining and retaining market-based rate authority, the provisions set forth in the entire section, including the restriction on affiliate sales of electric energy and the affiliate restrictions, must be satisfied on an ongoing basis. Paragraph (b) expressly prohibits sales between a franchised public utility with captive customers and any of its market-regulated power sales affiliates without first receiving authorization for the transaction under section 205 of the FPA. This paragraph requires that, where the Commission grants a seller authority to engage in affiliate sales under its MBR tariff, any and all such authorizations must be listed in the seller's tariff. The language varies from that proposed in the NOPR to reflect changes to the definition of ''franchised public utility.''

1097. Paragraphs (c)–(f) contain provisions governing the relationship between a franchised public utility with captive customers and its market-regulated power sales affiliates (formerly, code of conduct). The provisions of these paragraphs apply to all franchised public utilities with captive customers. These paragraphs include provisions governing the separation of employees, the sharing of market information, sales of non-power goods or services, and power brokering. The language varies from that proposed in the NOPR to reflect changes to the definition of ''franchised public utility'' and a number of other changes discussed in greater detail in the affiliate abuse section of this Final Rule.

1098. As discussed above in Affiliate Abuse, the Commission is adding several provisions concerning separation of functions and information sharing to more closely model the Commission's standards of conduct, as appropriate. In addition, the final regulations include a new paragraph (g) with a general prohibition on using anyone as a conduit to circumvent any of the affiliate restrictions, and a new paragraph (h) explaining that, if necessary, affiliate restrictions involving two or more franchised public utilities, one or more of whom has captive customers and one or more of whom does not, will be imposed on a case-by-case basis.

*6. Section 35.40 Ancillary Services*

1099. This provision restricts sales of ancillary services to those specific geographic markets for which the Commission has authorized market-based rate sales of such services. In the Final Rule, we delete proposed paragraph (b), which reflected the Internet posting and reporting requirements found in *Avista Corporation*,[1220] and which we find are no longer necessary, as discussed above in the section on Ancillary Services. We also delete proposed subsection (c), which described limitations on sales of ancillary services by third-party providers; we believe that the standard applicable tariff provision, which will be available on the Commission's Web site as it may be revised from time to time, will adequately apprise sellers of the current policy concerning third-party providers.

*7. Section 35.41 Market Behavior Rules*

1100. In Order No. 674, the Commission rescinded two of its market behavior rules and codified the remainder in § 35.37 of new Subpart H. The NOPR proposed to move these market behavior rules, unchanged, from § 35.37 to § 35.41. NASUCA submitted a number of substantive comments on these provisions. Because we did not propose any revisions to these rules, and we are not revising them substantively in this Final Rule, NASUCA's comments are beyond the scope of this proceeding. We are, however, taking this opportunity to make several minor corrections and stylistic edits to the market behavior rules.

[1220] *Avista Corporation*, 87 FERC ¶ 61,223, *order on reh'g*, 89 FERC ¶ 61,136 (1999).

*8. Section 35.42 Change in Status Reporting Requirement*

1101. This section incorporates the provision previously found at paragraph 35.27(c), which was codified by Order No. 652. The final regulatory text clarifies distinctions between generation facilities and transmission facilities, and incorporates minor revisions as discussed above in the section on Changes in Status.

1102. The Final Rule adds paragraph (c), which codifies the requirement that each seller include an appendix identifying specified assets with each pertinent change in status notification filed. The paragraph also directs readers to Appendix B for a sample asset appendix.

*9. Miscellaneous*

1103. The final regulations add the phrase ''unless otherwise permitted by Commission rule or order'' in several places throughout the regulations to make clear that these general provisions are not meant to override approvals granted in particular circumstances in other orders or rules.

1104. In this Final Rule, the Commission has deleted proposed § 35.42, MBR Tariff, which required sellers to have on file the MBR tariff of general applicability. That requirement has been modified, as explained above in the section on the MBR tariff; accordingly the regulation will not be adopted.

## VI. Information Collection Statement

1105. The Office of Management and Budget (OMB) regulations require approval of certain information collection and data retention requirements imposed by agency rules.[1221] Upon approval of a collection of information and data retention, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of this 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. As discussed herein, the Commission is amending its regulations to codify its requirements for obtaining and retaining market-based rate authorization, implementing a market-based rate tariff, and incorporating the change in status reporting requirement for sellers seeking market-based rate authority.

*Initial Market Power Analysis*

1106. The Commission has previously required utilities seeking market-based

[1221] 5 CFR 1320.11.

rate authority to file a market power analysis with the Commission; the Commission now codifies that requirement in the Commission's regulations. This Final Rule reflects the Commission's existing practice developed over the years through individual cases and will not impose any additional burden, with the following exception.

1107. Section 35.27(a) of the Commission's regulations[1222] currently provides that any public utility seeking market-based rate authority shall not be required to submit a generation market power analysis with respect to sales from capacity for which construction commenced on or after July 9, 1996. Under current procedures, if all the generation owned or controlled by an applicant for market-based rate authority and its affiliates in the relevant balancing authority area is post-July 9, 1996 generation, such seller is not required to submit a generation market power analysis. In this Final Rule, the Commission eliminates the express exemption provided in § 35.27(a). This change means that all new sellers seeking market-based rate authority on or after the effective date of the Final Rule issued in this proceeding, whether or not all of their and their affiliates' generation was built or acquired after July 9, 1996, must provide a market power analysis of their generation to support their application for market-based rate authority.

1108. Because the Commission allows a seller to make simplifying assumptions, where appropriate, and therefore to submit a streamlined analysis, the Commission believes that any burden of document preparation occasioned by the elimination of § 35.27(a) should be minimal. To the extent that there are greater costs for some sellers, the benefit of ensuring that markets do not become less competitive over time outweighs any additional costs.

*Updated Market Power Analyses*

1109. To retain market-based rate authority, the Commission currently requires that sellers file an updated market power analysis every three years. In this Final Rule, the Commission codifies the requirement that certain sellers with market-based rate authority file an updated analysis with the Commission to retain that authority. However, Category 1 sellers will be relieved of their existing obligation to file regularly scheduled updated market power analyses, as explained in the Implementation Process section of this Final Rule. Instead, sellers that believe they fall into Category 1 will be required to submit a filing with the Commission at the time that updated market power analyses for the seller's relevant market would otherwise be due (based on the regional schedule for updated market power analyses adopted in this Final Rule) explaining why the seller meets the Category 1 criteria, including a list of all generation assets (including nameplate or seasonal capacity amounts) owned or controlled by the seller and its affiliates grouped by balancing authority area. Once the Commission agrees that a seller meets the Category 1 criteria, that seller will not have to file regularly scheduled updated market power analyses. Category 2 sellers will retain their existing obligation to file a regularly scheduled updated market power analysis. Thus, Category 2 sellers will not face a greater burden to provide the Commission with the information required for an updated market power analysis.

1110. In addition, the elimination of § 35.27(a) also means that existing Category 2 sellers filing updated market power analyses on or after the effective date of the Final Rule issued in this proceeding, whether or not all of their and their affiliates' generation was built or acquired after July 9, 1996, must provide a market power analysis of their generation to support their continued market-based rate authority.

1111. Mirant argues that, with the elimination of the § 35.27(a) exemption, its cost of compliance will increase because it will have to prepare four updated market power analyses, each costing $20,000 to prepare and file, for companies that would have qualified for the § 35.27(a) exemption. Mirant states that only one of its subsidiaries would qualify as a Category 1 seller and Mirant still would have to make four updated market power analysis filings. On the other hand, other commenters state that the benefits of eliminating the § 35.27(a) exemption outweigh any added burdens.

1112. Because the Commission allows a seller to make simplifying assumptions and rely on previously filed analyses by other market participants, where appropriate, and therefore to submit a streamlined analysis, the Commission believes that any burden of document preparation occasioned by the elimination of § 35.27(a) should be minimal. To the extent that there are greater costs for some sellers, the benefit of ensuring that markets do not become less competitive over time outweighs any additional costs.

*Regional Review and Schedule*

1113. In the NOPR, the Commission proposed to require each seller to file an updated market power analysis for its relevant geographic market(s) on a schedule that will allow examination of the individual seller at the same time the Commission examines other sellers in these relevant markets and contiguous markets within a region from which power could be imported. The regional reviews would rotate by geographic region.

1114. Some commenters expressed concern that regional review would increase the burden associated with filing updated market power analyses. Reliant, for example, states that companies which engage in business in multiple regions of the United States would have to file several times over the three year schedule instead of once as is required currently.[1223] Other commenters support the regional review proposal. For example, NRECA maintains that the proposed regional approach will not impose an undue compliance burden on sellers. It notes that the regional review approach will ensure greater consistency in the data used to evaluate Category 2 sellers, citing the Commission's statement in the NOPR that the Commission ''will have before it a complete picture of the uncommitted capacity and simultaneous import capability into the relevant geographic markets under review.'' [1224] NRECA states that any increase in the burden on sellers hardly outweighs these substantial benefits. NRECA submits that the Commission has proposed a reasonable procedure to better ensure that market-based rate authority is granted only in appropriate circumstances. When compared with the burden, cost and time required by a cost-of-service rate regime, NRECA asserts that the burden of complying with the regional review approach will be minimal. APPA/TAPS describe the regional review proposed in the NOPR as a sensible proposal to conduct updated market power analyses on a rotating, regional basis to improve the quality and quantity of the data relied upon for market-based rate determinations and to provide the Commission with a more comprehensive picture of competitive conditions in regional markets. They assert that the Commission should not

[1222] 18 CFR 35.27(a).

[1223] Similarly, Allegheny, Mirant, FP&L, EEI, FirstEnergy, MidAmerican, TXU, Morgan Stanley, Financial Companies, and EPSA argue that large corporate families could find themselves in a perpetual triennial review that would place a substantial regulatory burden and expense on them.

[1224] NRECA reply comments at 28, citing NOPR at P 154.

sacrifice improvements to its market-based rate program to the interests of a few companies and that any increased financial cost to companies associated with regional reviews is outweighed by the companies' profits from market-based rate sales.

1115. We believe that the Commission's proposal properly and fairly balances the need to effectively, comprehensively, and accurately assess market power in wholesale markets with the desire to minimize any administrative burden associated with the filing and review of updated market power analyses. While we recognize that some sellers may file updates more frequently than currently, we have carefully balanced the interests of all involved, and we believe that regional reviews of updated market analyses will result in more accurate and complete data. This in turn will enhance the Commission's ability to continue to ensure that sellers either lack market power or have adequately mitigated such market power.

1116. Further, in light of commenters' concern with the regional review schedule, the Commission has modified the schedule as proposed in the NOPR. The NOPR proposed that regional reviews would rotate by geographic region with three regions reviewed per year. Some commenters expressed concerned that, because they operate in multiple regions, they would be required to file updated market power analyses every year rather than every three years. To address this concern, we are reducing the number of filings that sellers with generation in multiple regions will have to make by consolidating the regions and reducing the total number from nine to six. With fewer and larger regions, sellers will likely occupy fewer regions, necessitating fewer filings.

*Market-Based Rate Tariff*

1117. The NOPR proposed a tariff of general applicability (MBR tariff), which would provide greater consistency and reduce confusion regarding tariffs. The Commission recognized that the requirement to file the specified MBR tariff might cause a minimal burden of document preparation and organization for existing market-based rate sellers, but stated that long-term benefits would be realized for market participants as well as the Commission.

1118. In this Final Rule, we do not adopt the NOPR proposal to require all sellers to adopt a tariff of general applicability. Instead, we adopt a set of standard tariff provisions that we will require each seller to include in its market-based rate tariff. While we will require all market-based rate sellers to make compliance filings to modify their existing tariffs to reflect these standard provisions, these compliance filings are to be made by each seller the next time the seller proposes a tariff change, makes a change in status filing, or submits an updated market power analysis in accordance with the schedule in Appendix D, whichever occurs first.

1119. In the NOPR, the Commission also proposed that all market-based rate sellers file one market-based rate tariff per corporate family. Many commenters expressed concern with this proposal. In light of these concerns, we are not requiring sellers to file one market-based rate tariff per corporate family. Instead, we will allow sellers to elect whether to transact under a single market-based rate tariff for an entire corporate family or under separate tariffs.

*General*

1120. The Commission's regulations in 18 CFR Part 35 specify those reporting requirements that must be followed in conjunction with the filing of rate schedules under the FPA. The information provided to the Commission under 18 CFR Part 35 is identified for information collection and records retention purposes as FERC–516. Data collection FERC–516 applies to all reporting requirements covered in 18 CFR Part 35 including: electric rate schedule filings, market power analyses, tariff submissions, market-based rate analyses, and reporting requirements for changes in status for public utilities with market-based rate authority.

1121. The Commission is submitting these reporting and records retention requirements to OMB for its review and approval under section 3507(d) of the Paperwork Reduction Act.[1225] The Commission solicited comments on the Commission's need for this information, whether the information will have practical utility, the accuracy of provided burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected, and any suggested methods for minimizing the respondent's burden, including the use of automated information techniques. The Commission did not receive comments specifically addressing the burden estimates in the NOPR. With the exceptions of estimates regarding sellers' market-based rate tariffs, the number of market-based rate sellers, and the burden estimates for Category 1 sellers, we will use the same estimates here as in the NOPR.[1226]

1122. The number of respondents expected to file to revise market-based rate tariffs has increased from the estimate set forth in the NOPR, given our decision not to require one MBR tariff per corporate family. We expect some sellers will opt to submit a single corporate tariff, but we will estimate the total number to be filed to be approximately 1230, rather than 650 as reported in the NOPR. We will conform the number of responses to reflect this new estimate as well. However, we note that this number may be significantly less if sellers choose the option to file one market-based rate tariff per corporate family. Additionally, the Commission proposed in the NOPR that sellers file their MBR tariffs as directed in the rulemaking proceeding requiring the submission of electronic tariffs. However, in this Final Rule, we are requiring that sellers file their modified tariffs the next time sellers propose a tariff change, make a change in status filing, or submit an updated market power analysis. We have adjusted the number of responses to reflect this requirement.

*Burden Estimate:* The Public Reporting and records retention burden for all four reporting requirements and the records retention requirement is as follows.[1227]

[1225] 44 U.S.C. 3507(d).

[1226] We note that the number of market-based rate sellers has increased since issuance of the NOPR in May 2006.

[1227] These burden estimates apply only to this Final Rule and do not reflect upon all of FERC–516.

*Title:* Electric Rate Schedule Filings (FERC–516).

*Action:* Revised Collection.

*OMB Control No:* 1902–0096.

| Data collection | Number of respondents | Number of responses | Hours per response | Total annual hours |
|---|---|---|---|---|
| Initial Market Power Analysis | 120 | 120 | 130 | 15,600 |
| Market-Based Rate Tariff | 1230 | [1228] 410 | 6 | 2,460 |
| Category 1 Qualification Filings [1229] | 630 | [1230] 210 | 15 [1231] | 3,150 |
| Updated Analyses | 600 | [1233] 200 | 250 | 50,000 |
| Category 2 [1232] Totals | | | | 71,210 |

*Total Annual Hours for Collection:* (Reporting + record retention (if appropriate) = 71,210 hours.

*Information Collection Costs:* The total annual cost for Initial Market Power Analyses is estimated to be $2,340,000. Total annual cost for market-based rate tariffs is projected to be $369,000 for the first year. Total annual cost for Category 1 Qualification Filings is projected to be $472,500.[1234] Total annual cost for Updated Market Power Analyses Category 2 is projected to be $7,500,000. The hourly rate of $150 includes attorney fees, engineering consultation fees and administrative support. There are 2080 total work hours in a year. There are no filing fees associated with applications for market-based rate authority.

*Respondents* (Market Power Analysis; MBR Tariff; Triennial Review): Businesses or other for profit.

*Frequency of Responses*

Market Power Analyses: Occasionally; consistent with current practice, a market power analysis must be filed for each utility seeking market-based rate authority.

Market-Based Rate Tariffs: Once, consistent with the requirement that all sellers file modifications to their existing tariffs in accordance with the provisions in Appendix C.

Updated Market Power Analyses: Updated market power analysis filed every three years for Category 2 sellers seeking to retain market-based rate authority.

*Necessity of the Information*

Market Power Analyses: Consistent with current practice, the market power analysis helps inform the Commission as to whether an entity seeking market-based rate authority lacks market power, and whether sales by that entity will be just and reasonable.

Market-Based Rate Tariff: Market-based rate tariffs with standard provisions will improve the efficiency of the Commission in its analysis and determination of market-based rate authority. These will reduce document preparation time overall and provide utilities with the clearly defined expectations of the Commission.

Updated Market Power Analyses: The updated market power analyses allow the Commission to monitor market-based rate authority to detect changes in market power or potential abuses of market power. The updated market power analysis permits the Commission to determine that continued market-based rate authority will still yield rates that are just and reasonable.

*Internal review:* The Commission has conducted an internal review of the public reporting burden associated with the collection of information and assured itself, by means of internal review, that there is specific, objective support for this information burden estimate. Moreover, the Commission has reviewed the collections of information and has determined that these collections of information are necessary and conform to the Commission's plans, as described in this order, for the collection, efficient management, and use of the required information.[1235]

1123. Interested persons may obtain information on the reporting requirements by contacting: Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426 [Attention: Michael Miller, Office of the Executive Director, Phone: (202) 502–8415, fax: (202) 273–0873, e-mail: *michael.miller@ferc.gov* or the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission].

## VII. Environmental Analysis

1124. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[1236] The Commission concludes that neither an Environmental Assessment nor an Environmental Impact Statement is required for this Final Rule under § 380.4(a)(15) of the Commission's regulations, which provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to electric rate filings.[1237]

## VIII. Regulatory Flexibility Act

1125. The Regulatory Flexibility Act of 1980 (RFA) [1238] generally requires a description and analysis of rules that will have significant economic impact on a substantial number of small entities.[1239] The Final Rule will be

[1228] We expect responses to be staggered over the course of three years. Accordingly, the number of respondents (1230) has been divided by 3.

[1229] Category 1 sellers are power marketers and power producers that own or control 500 MW or less of generating capacity in aggregate and that are not affiliated with a public utility with a franchised service territory. In addition, Category 1 sellers must not own, operate or control transmission facilities, and must present no other vertical market power issues. There are approximately 630 Category 1 sellers.

[1230] To determine the number of responses, the number of respondents (630) has been divided by 3 because the Category 1 filings will be submitted to the Commission on a staggered basis over the course of a three-year period. After the first three years, the number of responses will be zero.

[1231] This estimate reflects the limited scope of the filing required by Category 1 sellers, *i.e.*, a filing explaining why the seller meets the Category 1 criteria and including a list of all generation assets owned or controlled by the seller and its affiliates grouped by balancing authority area.

[1232] Category 2 sellers are any sellers not in Category 1.

[1233] To determine the number of responses, the number of respondents (600) has been divided by 3 because the responses will be submitted to the Commission on a staggered basis over the course of a three year period.

[1234] We note that Category 1 sellers will only be required to file on a single occasion Category 1 qualification filings whereas Category 2 sellers will file updated market power analyses every three years.

[1235] *See* 44 U.S.C. 3506(c).

[1236] Order No. 486, *Regulations Implementing the National Environmental Policy Act,* 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. Preambles 1986–1990 ¶ 30,783 (1987).

[1237] 18 CFR 380.4(a)(15).

[1238] 5 U.S.C. 601–12.

[1239] The RFA definition of ''small entity'' refers to the definition provided in the Small Business Act,

Continued

applicable to all public utilities seeking and currently possessing market-based rate authority. The Commission finds that the regulations adopted here should not have a significant impact on small businesses.

1126. The submission of a market power analysis is currently required of all entities seeking authority to sell at market-based rates, and the Final Rule does not expand which entities will be required to file these analyses. The Final Rule does not create a new reporting requirement. It does, however, expand the scope of the analysis that must be submitted for those entities that previously were exempted from preparing a generation market power analysis by virtue of 18 CFR 35.27(a). The Commission is concerned that the continued use of the § 35.27(a) exemption, in time, would encompass all market participants as all pre-July 9, 1996 generation is retired. Nevertheless, because the Commission allows a seller to make simplifying assumptions, where appropriate, and therefore to submit a streamlined analysis, the Commission believes that any additional burden imposed by the elimination of the § 35.27(a) exemption will be minimal.

1127. Standard tariff provisions will decrease document preparation by clearly defining the information sought by the Commission.

1128. For certain sellers, the triennial review submissions that provide updated market power analyses are required for the retention of market-based rate authority. Category 2 utilities shall continue to submit this analysis, which poses no greater burden than that already in place. However, the regulations will result in fewer filings with the Commission after the next three years than currently required for qualified smaller (Category 1) utilities' retention of market-based rate authority. Thus, the Final Rule will be less burdensome economically and reduce the frequency of document preparation for market-based rate authority retention for qualified smaller utilities. The Commission concludes that this Final Rule will not have a significant economic impact on a substantial number of small entities.

which defines a ''small business concern'' as a business that is independently owned and operated and that is not dominant in its field of operation. 15 U.S.C. 632. The Small Business Size Standards component of the North American Industry Classification System defines a small electric utility as one that, including its affiliates, is primarily engaged in the generation, transmission, and/or distribution of electric energy for sale and whose total electric output for the preceding fiscal year did not exceed 4 million MWh. 13 CFR 121.201 (section 22, Utilities, North American Industry Classification System, NAICS).

## IX. Document Availability

1129. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (*http://www.ferc.gov*) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5 p.m. Eastern time) at 888 First Street, NE., Room 2A, Washington, DC 20426.

1130. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

1131. 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 e-mail at *ferconlinesupport@ferc.gov,* or the Public Reference Room at (202) 502–8371 Press 0, TTY (202) 502–8659. E-mail the Public Reference Room at *public.referenceroom@ferc.gov.*

## X. Effective Date and Congressional Notification

1132. These regulations are effective September 18, 2007. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a ''major rule'' as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996. The Commission will submit the Final Rule to both houses of Congress and to the General Accounting Office.

## List of Subjects in 18 CFR Part 35

Electric power rates, Electric utilities, Reporting and recordkeeping requirements.

By the Commission. Commissioner Moeller dissenting in part with a separate statement in Attachment A.

**Kimberly D. Bose,**

*Secretary.*

■ In consideration of the foregoing, the Commission amends part 35, Chapter I, Title 18, *Code of Federal Regulations,* as follows:

■ 1. The authority citation for part 35 continues to read as follows:

**Authority:** 16 U.S.C. 791a–825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 7101–7352.

■ 2. § 35.27 is revised to read as follows:

### § 35.27 Authority of State commissions.

Nothing in this part—

(a) Shall be construed as preempting or affecting any jurisdiction a State commission or other State authority may have under applicable State and Federal law, or

(b) Limits the authority of a State commission in accordance with State and Federal law to establish

(1) Competitive procedures for the acquisition of electric energy, including demand-side management, purchased at wholesale, or

(2) Non-discriminatory fees for the distribution of such electric energy to retail consumers for purposes established in accordance with State law.

■ 3. Subpart H is revised to read as follows:

### Subpart H—Wholesale Sales of Electric Energy, Capacity and Ancillary Services at Market-Based Rates

Sec.



## Subpart H—Wholesale Sales of Electric Energy, Capacity and Ancillary Services at Market-Based Rates

### § 35.36 Generally.

(a) For purposes of this subpart:

(1) *Seller* means any person that has authorization to or seeks authorization to engage in sales for resale of electric energy, capacity or ancillary services at market-based rates under section 205 of the Federal Power Act.

(2) *Category 1 Sellers* means wholesale power marketers and wholesale power producers that own or control 500 MW or less of generation in aggregate per region; that do not own, operate or control transmission facilities other than limited equipment necessary to connect individual generating facilities to the transmission grid (or have been granted waiver of the requirements of Order No. 888, FERC Stats. & Regs. ¶ 31,036); that are not affiliated with anyone that owns, operates or controls transmission facilities in the same region as the seller's generation assets; that are not affiliated with a franchised public utility in the same region as the seller's generation assets; and that do not raise other vertical market power issues.

(3) *Category 2 Sellers* means any Sellers not in Category 1.

(4) *Inputs to electric power production* means intrastate natural gas transportation, intrastate natural gas storage or distribution facilities; sites for generation capacity development; sources of coal supplies and equipment for the transportation of coal supplies such as barges and rail cars.

(5) *Franchised public utility* means a public utility with a franchised service obligation under State law.

(6) *Captive customers* means any wholesale or retail electric energy customers served under cost-based regulation.

(7) *Market-regulated power sales affiliate* means any power seller affiliate other than a franchised public utility, including a power marketer, exempt wholesale generator, qualifying facility or other power seller affiliate, whose power sales are regulated in whole or in part on a market-rate basis.

(8) *Market information* means non-public information related to the electric energy and power business including, but not limited to, information regarding sales, cost of production, generator outages, generator heat rates, unconsummated transactions, or historical generator volumes. Market information includes information from either affiliates or non-affiliates.

(b) The provisions of this subpart apply to all Sellers authorized, or seeking authorization, to make sales for resale of electric energy, capacity or ancillary services at market-based rates unless otherwise ordered by the Commission.

**§ 35.37 Market power analysis required.**

(a) (1) In addition to other requirements in subparts A and B, a Seller must submit a market power analysis in the following circumstances: when seeking market-based rate authority; for Category 2 Sellers, every three years, according to the schedule contained in Order No. 697, FERC Stats. & Regs. ¶ 31,252; or any other time the Commission directs a Seller to submit one. Failure to timely file an updated market power analysis will constitute a violation of Seller's market-based rate tariff.

(2) When submitting a market power analysis, whether as part of an initial application or an update, a Seller must include an appendix of assets in the form provided in Appendix B of this subpart.

(b) A market power analysis must address whether a Seller has horizontal and vertical market power.

(c) (1) There will be a rebuttable presumption that a Seller lacks horizontal market power if it passes two indicative market power screens: a pivotal supplier analysis based on the annual peak demand of the relevant market, and a market share analysis applied on a seasonal basis. There will be a rebuttable presumption that a Seller possesses horizontal market power if it fails either screen.

(2) Sellers and intervenors may also file alternative evidence to support or rebut the results of the indicative screens. Sellers may file such evidence at the time they file their indicative screens. Intervenors may file such evidence in response to a Seller's submissions.

(3) If a Seller does not pass one or both screens, the Seller may rebut a presumption of horizontal market power by submitting a Delivered Price Test analysis. A Seller that does not rebut a presumption of horizontal market power or that concedes market power, is subject to mitigation, as described in § 35.38.

(4) When submitting a horizontal market power analysis, a Seller must use the form provided in Appendix A of this subpart and include all supporting materials referenced in the form.

(d) To demonstrate a lack of vertical market power, a Seller that owns, operates or controls transmission facilities, or whose affiliates own, operate or control transmission facilities, must have on file with the Commission an Open Access Transmission Tariff, as described in § 35.28; provided, however, that a Seller whose foreign affiliate(s) own, operate or control transmission facilities outside of the United States that can be used by competitors of the Seller to reach United States markets must demonstrate that such affiliate either has adopted and is implementing an Open Access Transmission Tariff as described in § 35.28, or otherwise offers comparable, non-discriminatory access to such transmission facilities.

(e) To demonstrate a lack of vertical market power in wholesale energy markets through the affiliation, ownership or control of inputs to electric power production, such as the transportation or distribution of the inputs to electric power production, a Seller must provide the following information:

(1) A description of its ownership or control of, or affiliation with an entity that owns or controls, intrastate natural gas transportation, intrastate natural gas storage or distribution facilities;

(2) Sites for generation capacity development; and

(3) Sources of coal supplies and the transportation of coal supplies such as barges and rail cars.

(4) A Seller must ensure that this information is included in the record of each new application for market-based rates and each updated market power analysis. In addition, a Seller is required to make an affirmative statement that it has not erected barriers to entry into the relevant market and will not erect barriers to entry into the relevant market.

(f) If the seller seeks to protect any portion of the application, or any attachment thereto, from public disclosure pursuant to § 388.112 of this chapter, the seller must include with its request for privileged treatment a proposed protective order under which the parties to the proceeding will be able to review any of the data, information, analysis or other documentation relied upon by the seller for which privileged treatment is sought. A seller must grant access to privileged data to any party that signs a protective order within 5 days from the date that the party executes the protective order.

**§ 35.38 Mitigation.**

(a) A Seller that has been found to have market power in generation or that is presumed to have horizontal market power by virtue of failing or foregoing the horizontal market power screens, as described in § 35.37(c), may adopt the default mitigation detailed in paragraph (b) of this section or may propose mitigation tailored to its own particular circumstances to eliminate its ability to exercise market power. Mitigation will apply only to the market(s) in which the Seller is found, or presumed, to have market power.

(b) Default mitigation consists of three distinct products:

(1) Sales of power of one week or less priced at the Seller's incremental cost plus a 10 percent adder;

(2) Sales of power of more than one week but less than one year priced at no higher than a cost-based ceiling reflecting the costs of the unit(s) expected to provide the service; and

(3) New contracts filed for review under section 205 of the Federal Power Act for sales of power for one year or more priced at a rate not to exceed embedded cost of service.

**§ 35.39 Affiliate restrictions.**

(a) *General affiliate provisions.* As a condition of obtaining and retaining market-based rate authority, the conditions provided in this section, including the restriction on affiliate sales of electric energy and all other affiliate provisions, must be satisfied on an ongoing basis, unless otherwise authorized by Commission rule or order. Failure to satisfy these conditions will constitute a violation of the Seller's market-based rate tariff.

(b) *Restriction on affiliate sales of electric energy.* As a condition of obtaining and retaining market-based rate authority, no wholesale sale of electric energy may be made between a franchised public utility with captive customers and a market-regulated power sales affiliate without first receiving Commission authorization for the transaction under section 205 of the Federal Power Act. All authorizations to engage in affiliate wholesale sales of electric energy must be listed in a Seller's market-based rate tariff.

(c) *Separation of functions.* (1) For the purpose of this paragraph, entities acting on behalf of and for the benefit of a franchised public utility with captive customers (such as entities controlling or marketing power from the electrical generation assets of the franchised public utility) are considered part of the franchised public utility. Entities acting on behalf of and for the benefit of the market-regulated power sales affiliates of a franchised public utility with captive customers are considered part of the market-regulated power sales affiliates.

(2) (i) To the maximum extent practical, the employees of a market-regulated power sales affiliate must operate separately from the employees of any affiliated franchised public utility with captive customers.

(ii) Franchised public utilities with captive customers are permitted to share support employees, and field and maintenance employees with their market-regulated power sales affiliates. Franchised public utilities with captive customers are also permitted to share senior officers and boards of directors with their market-regulated power sales affiliates; provided, however, that the shared officers and boards of directors must not participate in directing, organizing or executing generation or market functions.

(iii) Notwithstanding any other restrictions in this section, in emergency circumstances affecting system reliability, a market-regulated power sales affiliate and a franchised public utility with captive customers may take steps necessary to keep the bulk power system in operation. A franchised public utility with captive customers or the market-regulated power sales affiliate must report to the Commission and disclose to the public on its Web site, each emergency that resulted in any deviation from the restrictions of section 35.39, within 24 hours of such deviation.

(d) *Information sharing.* (1) Unless simultaneously disclosed to the public, market information may not be shared between a franchised public utility with captive customers and a market-regulated power sales affiliate if the sharing could be used to the detriment of captive customers.

(2) Permissibly shared support employees, field and maintenance employees and senior officers and board of directors under §§ 35.39(c)(2)(ii) may have access to information covered by the prohibition of § 35.39(d)(1), subject to the no-conduit provision in § 35.39(g).

(e) *Non-power goods or services.* (1) Unless otherwise permitted by Commission rule or order, sales of any non-power goods or services by a franchised public utility with captive customers, to a market-regulated power sales affiliate must be at the higher of cost or market price.

(2) Unless otherwise permitted by Commission rule or order, sales of any non-power goods or services by a market-regulated power sales affiliate to an affiliated franchised public utility with captive customers may not be at a price above market.

(f) *Brokering of power.* (1) Unless otherwise permitted by Commission rule or order, to the extent a market-regulated power sales affiliate seeks to broker power for an affiliated franchised public utility with captive customers:

(i) The market-regulated power sales affiliate must offer the franchised public utility's power first;

(ii) The arrangement between the market-regulated power sales affiliate and the franchised public utility must be non-exclusive; and

(iii) The market-regulated power sales affiliate may not accept any fees in conjunction with any brokering services it performs for an affiliated franchised public utility.

(2) Unless otherwise permitted by Commission rule or order, to the extent a franchised public utility with captive customers seeks to broker power for a market-regulated power sales affiliate:

(i) The franchised public utility must charge the higher of its costs for the service or the market price for such services;

(ii) The franchised public utility must market its own power first, and simultaneously make public (on the Internet) any market information shared with its affiliate during the brokering; and

(iii) The franchised public utility must post on the Internet the actual brokering charges imposed.

(g) *No conduit provision.* A franchised public utility with captive customers and a market-regulated power sales affiliate are prohibited from using anyone, including asset managers, as a conduit to circumvent the affiliate restrictions in §§ 35.39(a) through (g).

(h) *Franchised utilities without captive customers.* If necessary, any affiliate restrictions regarding separation of functions, power sales or non-power goods and services transactions, or brokering involving two or more franchised public utilities, one or more of whom has captive customers and one or more of whom does not have captive customers, will be imposed on a case-by-case basis.

**§ 35.40 Ancillary services.**

A Seller may make sales of ancillary services at market-based rates only if it has been authorized by the Commission and only in specific geographic markets as the Commission has authorized.

**§ 35.41 Market behavior rules.**

(a) *Unit operation.* Where a Seller participates in a Commission-approved organized market, Seller must operate and schedule generating facilities, undertake maintenance, declare outages, and commit or otherwise bid supply in a manner that complies with the Commission-approved rules and regulations of the applicable market. A Seller is not required to bid or supply electric energy or other electricity products unless such requirement is a part of a separate Commission-approved tariff or is a requirement applicable to Seller through Seller's participation in a Commission-approved organized market.

(b) *Communications.* A Seller must provide accurate and factual information and not submit false or misleading information, or omit material information, in any communication with the Commission, Commission-approved market monitors, Commission-approved regional transmission organizations, Commission-approved independent system operators, or jurisdictional transmission providers, unless Seller exercises due diligence to prevent such occurrences.

(c) *Price reporting.* To the extent a Seller engages in reporting of transactions to publishers of electric or natural gas price indices, Seller must provide accurate and factual information, and not knowingly submit false or misleading information or omit material information to any such publisher, by reporting its transactions in a manner consistent with the procedures set forth in the Policy

Statement issued by the Commission in Docket No. PL03–3–000 and any clarifications thereto. Unless Seller has previously provided the Commission with a notification of its price reporting status, Seller must notify the Commission within 15 days of the effective date of this regulation or within 15 days of the date it begins making wholesale sales, whichever is earlier, whether it engages in such reporting of its transactions. Seller must update the notification within 15 days of any subsequent change in its transaction reporting status. In addition, Seller must adhere to such other standards and requirements for price reporting as the Commission may order.

(d) *Records retention.* A Seller must retain, for a period of five years, all data and information upon which it billed the prices it charged for the electric energy or electric energy products it sold pursuant to Seller's market-based rate tariff, and the prices it reported for use in price indices.

**§ 35.42 Change in status reporting requirement.**

(a) As a condition of obtaining and retaining market-based rate authority, a Seller must timely report to the Commission any change in status that would reflect a departure from the characteristics the Commission relied upon in granting market-based rate authority. A change in status includes, but is not limited to, the following:

(1) Ownership or control of generation capacity that results in net increases of 100 MW or more, or of inputs to electric power production, or ownership, operation or control of transmission facilities, or

(2) Affiliation with any entity not disclosed in the application for market-based rate authority that owns or controls generation facilities or inputs to electric power production, affiliation with any entity not disclosed in the application for market-based rate authority that owns, operates or controls transmission facilities, or affiliation with any entity that has a franchised service area.

(b) Any change in status subject to paragraph (a) of this section must be filed no later than 30 days after the change in status occurs. Power sales contracts with future delivery are reportable 30 days after the physical delivery has begun. Failure to timely file a change in status report constitutes a tariff violation.

(c) When submitting a change in status notification regarding a change that impacts the pertinent assets held by a Seller or its affiliates with market-based rate authorization, a Seller must include an appendix of assets in the form provided in Appendix B of this subpart.

## Appendix A to Subpart H

STANDARD SCREEN FORMAT

[Data provided for Illustrative Purposes only]

| Row | Generation | MW | Reference |
|---|---|---|---|
| | **Part I—Pivotal Supplier Analysis** | | |
| | **Seller and Affiliate Capacity** | | |
| A | Installed Capacity | 19,500 | Workpaper. |
| B | Long-Term Firm Purchases | 500 | Workpaper. |
| C | Long-Term Firm Sales | −1,000 | Workpaper. |
| D | Imported Power | 0 | Workpaper. |
| | **Non-Affiliate Capacity** | | |
| E | Installed Capacity | 8,000 | Workpaper. |
| F | Long-Term Firm Purchases | 500 | Workpaper. |
| G | Long-Term Firm Sales | −2,500 | Workpaper. |
| H | Imported Power | 3,500 | Workpaper. |
| I | Balancing Authority Area Reserve Requirement | −2,160 | Workpaper. |
| J | Amount of Line I Attributable to Seller, if any | −2,160 | Workpaper. |
| K | Total Uncommitted Supply (SUM A,B,C,D,E,F,G,I) | 9,840 | |
| | **Load** | | |
| L | Balancing Authority Area Annual Peak Load | 18,000 | Workpaper. |
| M | Average Daily Peak Native Load in Peak Month | −16,500 | Workpaper. |
| N | Amount of Line M Attributable to Seller, if any | −16,500 | Workpaper. |
| O | Wholesale Load (SUM L,M) | 1,500 | |
| P | Net Uncommitted Supply (K–O) | 8,340 | |
| Q | Seller's Uncommitted Capacity (SUM A,B,C,D,J,N) | 340 | |
| Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P) | | PASS | |

| Row | | Q1 (MW) | Q2 (MW) | Q3 (MW) | Q4 (MW) | Reference |
|---|---|---|---|---|---|---|
| | **Part II—Market Share Analysis** | | | | | |
| | **Seller and Affiliate Capacity** | | | | | |
| A | Installed Capacity | 19,500 | 19,500 | 19,500 | 19,500 | Workpaper. |
| B | Long-Term Firm Purchases | 500 | 500 | 500 | 500 | Workpaper. |
| C | Long-Term Firm Sales | −1,000 | −1,000 | −1,000 | −1,000 | Workpaper. |
| D | Seasonal Average Planned Outages | −4,000 | −3,000 | −800 | −3,500 | Workpaper. |
| E | Imported Power | 0 | 0 | 0 | 0 | Workpaper. |
| | **Capacity Deductions** | | | | | |
| F | Average Peak Native Load in the Season | −11,500 | −10,000 | −12,500 | −11,500 | Workpaper. |
| G | Amount of Line F Attributable to Seller, if any | −11,500 | −10,000 | −12,500 | −11,500 | Workpaper. |
| H | Amount of Line F Attributable to Others, if any | 0 | 0 | 0 | 0 | Workpaper. |
| I | Balancing Authority Area Reserve Requirement | −1,500 | −1,320 | −1,560 | −1,500 | Workpaper. |
| J | Amount of Line I Attributable to Seller, if any | −1,500 | −1,320 | −1,560 | −1,500 | Workpaper. |
| K | Amount of Line I Attributable to Others, if any | 0 | 0 | 0 | 0 | Workpaper. |
| | **Non-Affiliate Capacity** | | | | | |
| L | Installed Capacity | 8,000 | 8,000 | 8,000 | 8,000 | Workpaper. |
| M | Long-Term Firm Purchases | 500 | 500 | 500 | 500 | Workpaper. |
| N | Long-Term Firm Sales | −2,500 | −2,500 | −2,500 | −2,500 | Workpaper. |
| O | Local Seasonal Average Planned Outages | −800 | −200 | −300 | −400 | Workpaper. |
| P | Uncommitted Capacity Imports | 5,000 | 4,500 | 3,500 | 4,000 | Workpaper. |
| | **Supply Calculation** | | | | | |
| Q | Total Competing Supply (SUM L,M,N,O,P,H,K) | 10,200 | 10,300 | 9,200 | 9,600 | |
| R | Seller's Uncommitted Capacity (SUM A,B,C,D,E,G,J) | 2,000 | 4,680 | 4,140 | 2,500 | |
| S | Total Seasonal Uncommitted Capacity (SUM Q,R) | 12,200 | 14,980 | 13,340 | 12,100 | |
| T | Seller's Market Share (R/S) | 16.39% | 31.24% | 31.03% | 20.66% | |
| | Results (Pass if < 20%) (Fail if ≥ 20%) | PASS | FAIL | FAIL | FAIL | |

## Appendix B to Subpart H

This is an example of the required appendix listing the filing entity and all its energy affiliates and their associated assets which should be submitted with all market-based rate filings.

MARKET-BASED RATE AUTHORITY AND GENERATION ASSETS

| Filing entity and its energy affiliates | Docket No. where MBR authority was granted | Generation name | Owned by | Controlled by | Date control transferred | Location | | In-service date | Nameplate and/or seasonal rating |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Balancing authority area | Geographic region (per Appendix D) | | |
| ABC Corp. | ER05–23X–000 | ABC falls plant #1 | ABC Corp | ABC Corp | NA* | ABC balancing authority area. | Central | 8/12/1981 | 153.5 MW (seasonal). |
| xyz Inc. | ER94–79XX–000 | NA | NA | NA | NA | NA | NA | NA | NA. |
| RST LLC | ER01–2XX5–000 | Green CoGen | WWW Corp | RST LLC | 5/23/2005 | New York ISO. | Northeast | 12/20/2003 | 2000 MW (nameplate). |
| Sample Co. | ER03–XX45–000 | Sample Co. 3 | Sample Co | YYY Corp | 2/1/1982 | Sample Co. balancing authority. | Southwest | 5/13/1973 | 10 MW (seasonal). |

*If an entity has no assets or the field is not applicable please indicate so by inputting (NA).

ELECTRIC TRANSMISSION ASSETS AND/OR NATURAL GAS INTRASTATE PIPELINES AND/OR GAS STORAGE FACILITIES

| Filing entity and its energy affiliates | Asset name and use | Owned by | Controlled by | Date control transferred | Location | | Size |
|---|---|---|---|---|---|---|---|
| | | | | | Balancing authority area | Geographic region (per Appendix D) | |
| ABC Corp | CBA Line, used to interconnect Green Cogen to New York ISO transmission system. | ABC Corp | ABC Corp | NA* | New York ISO | Northeast | approximately five-mile, 500 kV line. |
| Etc. LP | Nowhere Pipeline, used to connect Storage LLC's—Longway Pipeline to ABC falls plant #1. | Etc. LP | Etc. LP | NA | ABC balancing authority area. | Central | approximately 14 miles of natural gas pipeline and related equipment with 50 MMcf/d capacity. |

*If the field is not applicable please indicate so by inputting (NA).

**Note:** The following appendices will not be published in the Code of Federal Regulations.

## Appendix C to the Final Rule

### Required Provisions of the Market-Based Rate Tariff

*Compliance With Commission Regulations*

Seller shall comply with the provisions of 18 CFR Part 35, Subpart H, as applicable, and with any conditions the Commission imposes in its orders concerning seller's market-based rate authority, including orders in which the Commission authorizes seller to engage in affiliate sales under this tariff or otherwise restricts or limits the seller's market-based rate authority. Failure to comply with the applicable provisions of 18 CFR Part 35, Subpart H, and with any orders of the Commission concerning seller's market-based rate authority, will constitute a violation of this tariff.

*Limitations and Exemptions Regarding Market-Based Rate Authority*

[Seller should list all limitations (including markets where seller does not have market-based rate authority) on its market-based rate authority and any exemptions from or waivers granted of Commission regulations and include relevant cites to Commission orders].

### Include All of the Following Provisions That Are Applicable

*Mitigated Sales*

Sales of energy and capacity are permissible under this tariff in all balancing authority areas where the Seller has been granted market-based rate authority. Sales of energy and capacity under this tariff are also permissible at the metered boundary between the Seller's mitigated balancing authority area and a balancing authority area where the Seller has been granted market-based rate authority provided: (i) Legal title of the power sold transfers at the metered boundary of the balancing authority area; (ii) any power sold hereunder is not intended to serve load in the seller's mitigated market; and (iii) no affiliate of the mitigated seller will sell the same power back into the mitigated seller's mitigated market. Seller must retain, for a period of five years from the date of the sale, all data and information related to the sale that demonstrates compliance with items (i), (ii) and (iii) above.

*Ancillary Services*

RTO/ISO Specific—Include All Services the Seller Is Offering

PJM: Seller offers regulation and frequency response service, energy imbalance service, and operating reserve service (which includes spinning, 10-minute, and 30-minute reserves) for sale into the market administered by PJM Interconnection, L.L.C. (''PJM'') and, where the PJM Open Access Transmission Tariff permits, the self-supply of these services to purchasers for a bilateral sale that is used to satisfy the ancillary services requirements of the PJM Office of Interconnection.

New York: Seller offers regulation and frequency response service, and operating reserve service (which include 10-minute non-synchronous, 30-minute operating reserves, 10-minute spinning reserves, and 10-minute non-spinning reserves) for sale to purchasers in the market administered by the New York Independent System Operator, Inc.

New England: Seller offers regulation and frequency response service (automatic generator control), operating reserve service (which includes 10-minute spinning reserve, 10-minute non-spinning reserve, and 30-minute operating reserve service) to purchasers within the markets administered by the ISO New England, Inc.

California: Seller offers regulation service, spinning reserve service, and non-spinning reserve service to the California Independent System Operator Corporation (''CAISO'') and to others that are self-supplying ancillary services to the CAISO.

Third Party Provider

Third-party ancillary services [include all of the following that the seller is offering: Regulation Service, Energy Imbalance Service, Spinning Reserves, and Supplemental Reserves]. Sales will not include the following: (1) Sales to an RTO or an ISO, *i.e.*, where that entity has no ability to self-supply ancillary services but instead depends on third parties; (2) sales to a traditional, franchised public utility affiliated with the third-party supplier, or sales where the underlying transmission service is on the system of the public utility affiliated with the third-party supplier; and (3) sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers.

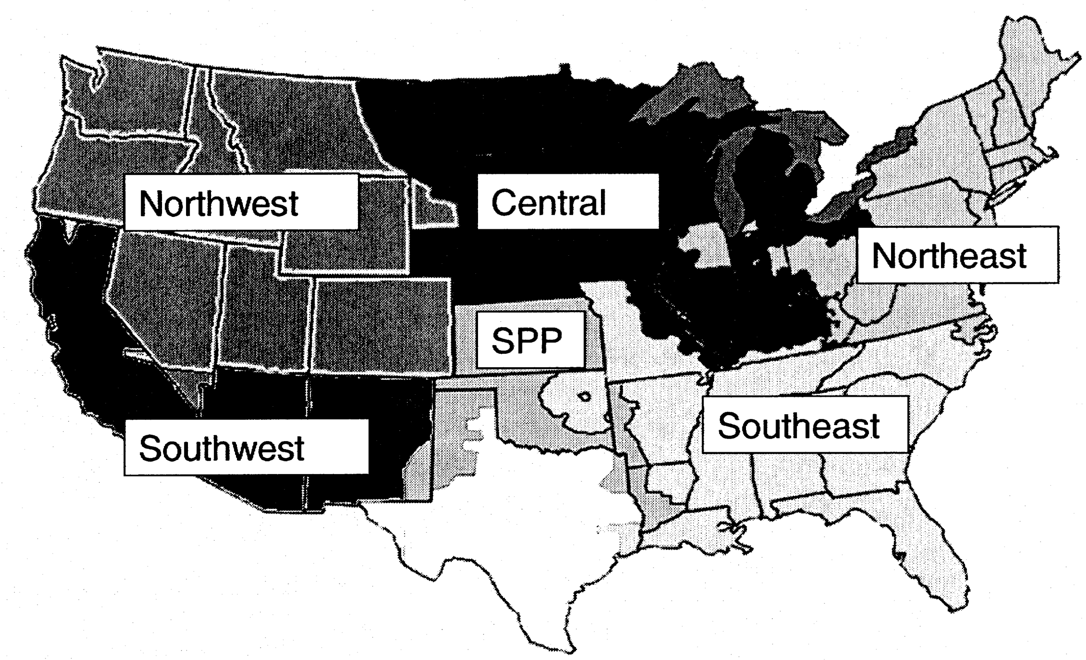
## Appendix D to the Final Rule

### Regions and Schedule for Regional Market Power Update Process

The six regions are combinations of NERC regions; RTOs and ISOs and are depicted in the map that follows.

BILLING CODE 6717–01–P

## Map of Geographic Regions




[ ] Northeast (ISO-NE, NYISO, PJM)

[ ] Southeast (NERC Regions SERC and FRCC (not including PJM or Midwest ISO))

[ ] Central (Midwest ISO, NERC Region MRO)

[ ] Southwest Power Pool (NERC region SPP)

[ ] Southwest (California, NERC region WECC-AZNMSNV)

[ ] Northwest (NERC Regions WECC-NWPP and WECC-RMPA)

BILLING CODE 6717–01–C

REGIONAL MARKET POWER UPDATE SCHEDULE

| Study period | Filing period (anytime between) | Entities required to file | |
|---|---|---|---|
| 2006 | December 1–30, 2007 | Northeast Transmission Operators. | |
| 2006 | June 1–30, 2008 | Southeast Transmission Operators. | All others in Northeast that did not file in December including all power marketers that sold in the Northeast. |
| 2006 | December 1–30, 2008 | ............................................... | All others in Southeast that did not file in June including all power marketers that sold in the Southeast and have not already been found to be Category 1 sellers. |
| 2007 | December 1–30, 2008 | Central Transmission Operators. | |
| 2007 | June 1–30, 2009 | SPP Transmission Operators | All others in Central that did not file in December including all power marketers that sold in the Central and have not already been found to be Category 1 sellers. |
| 2007 | December 1–30, 2009 | ............................................... | All others in SPP that did not file in June including all power marketers that sold in SPP and have not already been found to be Category 1 sellers. |
| 2008 | December 1–30, 2009 | Southwest Transmission Operators. | |
| 2008 | June 1–30, 2010 | Northwest Transmission Operators. | All others in Southwest that did not file in December including all power marketers that sold in the Southwest and have not already been found to be Category 1 sellers. |
| 2008 | December 1–30, 2010 | ............................................... | All others in Northwest that did not file in June including all power marketers that sold in the Northwest and have not already been found to be Category 1 sellers. |
| 2009 | December 1–30, 2010 | Northeast Transmission Operators. | |
| **All Category 1 sellers should be identified by the Commission prior to the subsequent filing periods. Only Category 2 sellers will continue to file updated market power analyses according to the repeating schedule below.** | | | |
| 2009 | June 1–30, 2011 | Southeast Transmission Operators. | Others in Northeast that did not file in December and have not been found to be Category 1 sellers. |
| 2009 | December 1–30, 2011 | ............................................... | Others in Southeast that did not file in June and have not been found to be Category 1 sellers. |
| 2010 | December 1–30, 2011 | Central Transmission Operators. | |
| 2010 | June 1–30, 2012 | SPP Transmission Operators | Others in Central that did not file in December and have not been found to be Category 1 sellers. |
| 2010 | December 1–30, 2012 | ............................................... | Others in SPP that did not file in June and have not been found to be Category 1 sellers. |
| 2011 | December 1–30, 2012 | Southwest Transmission Operators. | |
| 2011 | June 1–30, 2013 | Northwest Transmission Operators. | Others in Southwest that did not file in December and have not been found to be Category 1 sellers. |
| 2011 | December 1–30, 2013 | ............................................... | Others in Northwest that did not file in June and have not been found to be Category 1 sellers. |

This review cycle will be repeated in subsequent years.

## Appendix E to the Final Rule

### List of Commenters and Acronyms

Allegheny Energy Supply Co. and Allegheny Power—Allegheny Energy Companies
Alliance for Cooperative Energy Services Power Marketing LLC—Alliance Power Marketing
Ameren Services Co., Inc.—Ameren
AARP—AARP
American Public Power Association/Transmission Access Policy Study Group—APPA/TPAS
American Wind Energy Association—AWEA
Avista Corp.—Avista
Board of Water, Light and Sinking Fund Commissioners of the City of Dalton, Georgia—Dalton Utilities
California Electricity Oversight Board—California Board
California Independent System Operator Corp.—CAISO
California Public Utilities Commission—California Commission
Coalition of Midwest Transmission Customers, PJM Industrial Customer Coalition, NEPOOL Industrial Customer Coalition, Industrial Energy Users of Ohio, Southeast Electricity Consumers Association, Southwest Industrial Customer Coalition—Industrial Customers
Cogentrix Energy, Inc. and Goldman Sachs Group—Cogentrix/Goldman
Constellation Energy Group, Inc.—Constellation
Consumers Energy Co.—Consumers
Dominion Resources Services, Inc.—Dominion
Duke Energy Corp.—Duke
Duquesne Power, LLC; Duquesne Light Company; Duquesne Keystone, LLC; Duquesne Conemaugh, LLC; and Monmouth Energy, Inc.—Duquesne Companies
E.ON U.S. LLC—E.ON U.S.
Edison Electric Institute—EEI
ElectriCities of North Carolina, Inc. and Piedmont Municipal Power Agency—Carolina Agencies
Electricity Consumers Resource Council—ELCON
El Paso E&P Co. L.P.—El Paso E&P
Electric Power Supply Association—EPSA
Entergy Services, Inc.—Entergy
FirstEnergy Service Co.—FirstEnergy
Florida Power & Light Company and FPL Energy, LLC—FP&L
Indianapolis Power & Light Co.—Indianapolis P&L
ISO New England Inc.—ISO–NE
Joe Pace, PhD—Dr. Pace
Mark B. Lively—Mr. Lively

Merrill Lynch Commodities Inc., J.P. Morgan Ventures Energy Corp. and Bear Energy—Financial Companies
MidAmerican Energy Co. and PacifiCorp—MidAmerican
Midwest Energy, Inc.—Midwest Energy
Mirant Corp.—Mirant
Montana Consumer Counsel—Montana Counsel
Morgan Stanley Capital Group Inc.—Morgan Stanley
National Association of State Utility Consumer Advocates—NASUCA
National Rural Electric Cooperative Association—NRECA
New Jersey Board of Public Utilities—New Jersey Board
New Mexico Office of Attorney General, Colorado Office of Consumer Counsel, Utah Committee of Consumer Services, Public Citizen, Public Utility Law Project of New York, Rhode Island Office of Attorney General, and Rhode Island Division of Public Utilities and Carriers—State AGs and Advocates
New York Independent System Operator, Inc.—NYISO
New York State Public Service Commission—New York Commission
Newfoundland and Labrador Hydro—NL Hydro
Newmont Mining Corp.—Newmont
NiSource Inc.—NiSource
NRG Energy, Inc.—NRG
Oregon Public Utilities Commission—Oregon Commission
Ormet Power Marketing—Ormet
Pacific Gas & Electric Co.—PG&E
Piedmont Municipal Power Agency and ElectriCities of North Carolina—Carolina Agencies
Pinnacle West Companies—Pinnacle
Powerex Corp.—Powerex
PPL Companies—PPL
PPM Energy, Inc.—PPM
Progress Energy, Inc.—Progress Energy
Public Service Electric and Gas Company, PSEG Power LLC and PSEG Energy Resources & Trade LLC—PSEG Companies
Public Service Co. of New Mexico/Tuscon Electric Power Company—PNM/Tuscon
Public Works Commission for the City of Fayetteville, North Carolina—Fayetteville
Puget Sound Energy, Inc.—Puget
Reliant Energy, Inc.—Reliant
Richard Blumenthal, Attorney General for the State of Connecticut and the People of the State of Illinois, by and through the Illinois Attorney General, Lisa Madigan—Attorneys General of Connecticut and Illinois
Romkaew Broehm, PhD. and Peter Fox-Penner—Drs. Broehm and Fox-Penner
Sempra Energy—Sempra
Southern California Edison Co.—SoCal Edison
Southern Company Services, Inc.—Southern
Southwest Industrial Customer Coalition—Southwest Coalition
Suez Energy North America, Inc. and Chevron USA Inc.—Suez/Chevron
Towns of Black Creek, NC; Dallas, NC; Forest City, NC; Lucama, NC; Sharpsburg, NC; Stantonsburg, NC; and Waynesville, NC—NC Towns
Transmission Dependent Utility Systems—TDU Systems
TXU Portfolio Management Co. LP—TXU Wholesale
Westar Energy, Inc. and Kansas Gas and Electric Co.—Westar
Williams Power Co., Inc.—Williams
Wisconsin Electric Power Co.—Wisconsin Electric
Xcel Energy Services Inc.—Xcel

**Note:** The following attachment will not appear in the Code of Federal Regulations

## Attachment A to the Final Rule

MOELLER, Commissioner, dissenting in part: I find persuasive the arguments raised by commenters [1240] that a limited grandfathering provision for the ''1996 exemption'' [1241] is warranted, to avoid modifying the understanding that certain generators relied upon to finance and construct new generation. It is my position that, with respect to sales from capacity for which construction commenced on or after July 9, 1996, but before the effective date of this Final Rule, any public utility that has authority to engage in market-based rate sales should not be required to demonstrate a lack of market power in generation consistent with the terms of the exemption. That is, any public utility that qualified and received a 1996 exemption should retain its exemption from filing a generation market power analysis (now termed horizontal market power analysis). However, any increase in such capacity after the effective date of this Final Rule would terminate the exemption.

As I have stated previously, I am interested in providing regulatory certainty, and promoting infrastructure investment and independent power production. A limited grandfathering of the 1996 exemption would, on one hand, allow entities to continue to preserve the bargain they received when they relied on the exemption and, on the other hand, support the majority's reasons for revoking the exemption for all generators.

Also, my understanding is that very few entities would be eligible for this limited grandfathering; even without the grandfathering, they would probably be classified as ''Category 1 sellers.'' [1242] Moreover, this exemption neither precludes any entity from presenting evidence to the Commission, nor disallows the Commission of its own accord, to investigate an allegation of market power abuse by an exempt generator. This should allay any fears that these smaller entities will be able to exercise generation market power.[1243]

Philip D. Moeller
*Commissioner.*

[FR Doc. E7–13675 Filed 7–19–07; 8:45 am]

**BILLING CODE 6717–01–P**

[1240] Such commenters include EPSA, Mirant and Constellation.

[1241] 18 CFR 35.27(a) (2006), which states ''Notwithstanding any other requirements, any public utility seeking authorization to engage in sales for resale of electric energy at market-based rates shall not be required to demonstrate any lack of market power in generation with respect to sales from capacity for which construction has commenced on or after July 9, 1996.''

[1242] ''The sellers that have taken advantage of the exemption will largely qualify as Category 1 sellers, and thus will be unaffected to the extent that they will not be required to file a regularly scheduled updated market power analysis.'' Final Rule at P 321.

[1243] In defending our decision to create Category 1 sellers, the majority observes that no commenter has submitted compelling evidence that Category 1 sellers have unmitigated market power. Final Rule at P 334.

Federal Register

Friday,

July 20, 2007

## Part III

# Department of Housing and Urban Development

24 CFR Parts 203 and 206

**Adjustable Rate and Home Equity Conversion Mortgages—Additional Index; Final Rule**

**DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT**

**24 CFR Parts 203 and 206**

**[Docket No. FR–4969–F–02]**

**RIN 2502–AI32**

# Adjustable Rate and Home Equity Conversion Mortgages—Additional Index

**AGENCY:** Office of the Assistant Secretary for Housing—Federal Housing Commissioner, HUD.

**ACTION:** Final rule.

**SUMMARY:** This final rule adds: The one-year London Interbank Offered Rate (LIBOR) as an acceptable index for the HUD-insured one-, 3-, 5-, 7-, and 10-year Adjustable Rate Mortgage (ARM) products, and the one-month Constant Maturity Treasury (CMT), the one-month LIBOR, and the one-year (12-month) LIBOR as acceptable indices to adjust interest rates on the HUD-insured Home Equity Conversion Mortgage (HECM). Under current regulations, only the weekly average yield of U.S. Treasury securities, adjusted to a constant maturity of one year (commonly referred to as the one-year CMT), may be used to adjust interest rates on HUD-insured ARMs and HECMs. This final rule follows a June 19, 2006, proposed rule and includes HECMs in response to public comment on the June 19, 2006, proposed rule.

**DATES:** *Effective Date:* August 20, 2007.

**FOR FURTHER INFORMATION CONTACT:** James Beavers, Deputy Director, Single Family Program Development, Office of Single Family Housing, Office of Housing, Department of Housing and Urban Development, 451 Seventh Street, SW., Washington, DC 20410–8000; telephone number (202) 708–2121 (this is not a toll-free number). Persons with hearing or speech impairments may access this number through TTY by calling the toll-free Federal Information Relay Service at (800) 877–8339.

**SUPPLEMENTARY INFORMATION**

## I. Background

The previous policy of HUD's Federal Housing Administration (FHA) Single Family mortgage programs had been to use the weekly average yield of U.S. Treasury securities adjusted to a constant maturity of one year as the basis for interest rate adjustments on HUD-insured ARM loans and to determine interest rates on HECM loans. HUD believed that indices calculated and published by the U.S. Government were appropriate for mortgage loans insured by the U.S. Government (see HUD's responses to public comments on hybrid ARMs, as presented in the final rule published on March 10, 2004, at 69 FR 11500). However, the growing popularity of the LIBOR index, including its acceptance in the secondary mortgage market, has led to a change in HUD's policy on this issue.

LIBOR is both an international index determined on the basis of the world economy and an index that has recently become widely used for ARM loans in the United States. LIBOR-based loans have become very popular in the secondary market, and this greater liquidity allows lenders to offer lower margins to borrowers.

The LIBOR indices and the corresponding CMT indices have historically tracked each other closely over time. While the LIBOR rate may often be slightly higher, the better margins available for LIBOR-indexed loans often make LIBOR-based loans a better deal for consumers.

In addition, as LIBOR loans become more popular, it is necessary for HUD to offer a LIBOR option to remain competitive in the secondary market. With the large number of lenders now offering LIBOR-based ARM loans, to be competitive it no longer makes economic sense for FHA to restrict itself to the Treasury index.

Under the authority of section 251(a) of the National Housing Act (12 U.S.C. 1715z–16(a)), HUD may set by regulation a national interest rate index, and information on the index must be readily available to mortgagors. The one-month LIBOR and the one-year LIBOR are widely published and meet this availability requirement. Information on LIBOR rates is readily available through a variety of media, including the Internet.

## II. The June 19, 2006, Proposed Rule

On June 19, 2006, HUD published a proposed rule that would amend HUD's regulations at 24 CFR 203.49(b) to add the LIBOR index as an acceptable index for determining interest rate adjustments of HUD-insured ARMs (see 71 FR 35370). The proposed rule did not cover HECM loans, which are governed by separate regulations at 24 CFR part 206.

## III. This Final Rule; Significant Changes to the June 19, 2006, Proposed Rule

In response to public comments, which are discussed in Section IV, this final rule adds HECM loans as eligible to use the LIBOR indices.

## IV. Discussion of Public Comments Received on the June 19, 2006, Proposed Rule

The public comment period of the June 19, 2006, proposed rule closed on August 18, 2006, and HUD received five comments on the proposed rule. Comments were received from three trade organizations representing mortgage bankers and home builders, the home mortgage division of a bank, and a residential mortgage group.

All five commenters supported HUD's proposal to add LIBOR as an acceptable index for adjusting the interest rate of HUD-insured ARM products. The commenters wrote that the inclusion of the LIBOR allows lenders greater flexibility in offering ARM products, provides an incentive for more lenders to use the FHA program, and broadens mortgage options for FHA borrowers. Two of the commenters requested that HUD extend the availability of the LIBOR index to HUD's HECM products. The commenters wrote that the same reasoning and benefits apply for allowing the LIBOR indices to be used with the HECM program.

After careful consideration of the comments requesting that the LIBOR index be allowed for HUD's HECM products, HUD has decided to include the aforementioned LIBOR indices as an option in HUD's HECM programs. Inclusion of the LIBOR as acceptable indices for HECM products does not impose any requirement on regulated entities or on the public. Rather, it permits the use of alternative indices for calculating interest rate adjustments and the expected average mortgage interest rate on HECM loans. Mortgage lenders that do not wish to use the LIBOR indices as the basis for the interest rate adjustments on HUD-insured HECMs can continue using the current one-year CMT index. HUD's HECM regulations are also being amended to allow the one-month CMT or one-month LIBOR as an option for lenders and borrowers. Similarly, while this rule adds another option for determining interest rate adjustments and expected average mortgage interest rates, members of the public continue to have access to HUD-insured HECMs based on the U.S. Treasury security indices. Further, as administered, the loans provided today under the HECM program are predominantly ARMs. Allowing the LIBOR indices to be used for HECMs is consistent with current HUD policy, as expressed in this final rule. Not only does the inclusion of the LIBOR indices for HECMs foster consistency within HUD's regulations, but it also conforms HUD practice to that of the rest of the mortgage industry, which offers LIBOR-based ARM and reverse mortgage loans.

Section 255 of the National Housing Act, 12 U.S.C. 1715z-20, provided for the establishment of the HECM program. The HECM provides elderly homeowners with an opportunity to convert home equity into monthly streams of income and/or lines of credit. In establishing the HECM loan, the lender must compute two interest rates. The first interest rate is the expected average mortgage interest rate, which is a rate that remains fixed for the life of the loan and is used to calculate the loan's principal limit and payment plan. A long-term rate is utilized as the benchmark for the expected average mortgage interest rate, as it better predicts performance for the life of the loan than does a short-term rate. The second interest rate computed is the mortgage interest (accrual or note) rate, which is a short-term rate. Currently, the fixed HECM expected rate and the adjustable HECM mortgage interest rates are both tied to yields on U.S. Treasury securities, which are adjusted to a constant maturity of one year for the mortgage interest rate and to a constant maturity of 10 years for the expected average mortgage interest rate.

HUD's regulations at 24 CFR 206.3 are being amended to add the LIBOR index as an acceptable index for determining interest rate adjustments of HECM loans. The rule now adds the one-month CMT, the one-month LIBOR, and the one-year LIBOR as acceptable indices to adjust interest rates on the HECM, and to require use of the 10-year LIBOR swap rate to establish the expected average mortgage interest rate on the HECM product, if the note is indexed to either the one-month or one-year LIBOR rate. The rule provides additional options in the case of monthly adjusting HECM loans, in that it provides for the option, which may be preferable, of using the one-month LIBOR index or one-month CMT index to adjust the interest rate of monthly adjusting HECM loans. However, the one-year CMT may continue to be used to adjust the interest rate of monthly adjustable HECM loans. The rule also provides for the option of using the one-year LIBOR index or one-year CMT index to adjust the interest rate of annually adjusting HECM loans.

In order to calculate the expected average mortgage interest rate on either monthly adjusting or annually adjusting HECMs indexed to LIBOR, the U.S. dollar denominated 10-year LIBOR swap rate will be used. Since LIBOR rates are short-term rates (ranging from maturities of one week through 12 months), the financial community relies on the LIBOR ''swap rate curve'' to calculate the LIBOR-based interest rate yield curve for maturities greater than one year. The U.S. dollar-denominated LIBOR swap rate curve shows the fixed-rate leg (i.e., portion of the swap) of ordinary fixed-for floating rate swap contracts where the floating-rate leg is the 6-month LIBOR rate expressed in dollars.

A swap is a financial derivative under which two parties exchange two streams of future cash flows. The transaction is called a ''plain vanilla'' interest-rate swap if both cash flow streams are in the same currency and involve an exchange of fixed-rate for floating-rate interest payments on the same hypothetical (or ''notional'') loan amount. For example, in the case of a plain vanilla interest rate swap with a term of 10 years, the banks could agree to swap fixed-rate dollar payments at 5.1 percent on a notional loan amount of $100,000 in exchange for dollar-denominated 6-month LIBOR payments on the same notional loan amount. The 5.1 percent fixed-rate leg of the swap contract would correspond to the 10-year point on the LIBOR swap rate curve.

As such, the U.S. dollar-denominated 10-year LIBOR swap rate is a long-term market-based interest rate calculation that is driven by factors similar to those that affect the 10-year CMT. Not only does the 10-year LIBOR swap rate derive from a calculation of what the one-year LIBOR index would be if it operated on a long-term basis, but it also has historically performed closely to the 10-year CMT.

The addition of the LIBOR indices is beneficial to homeowners as well as entities in the mortgage community. Use of the LIBOR indices would attract new investors to HECMs, thus increasing liquidity in the secondary mortgage market, which in turn would drive down costs and interest rates for the mortgagor. Therefore, HUD believes it is reasonable to permit the use of LIBOR indices for HECM loans at the final rule phase.

In addition to the comments requesting the availability of the LIBOR index in HUD's HECM program, the following two comments were also made.

*Comment: Borrowers need sufficient information so that they can make informed decisions.* One commenter wrote that HUD should include in the regulation a disclosure requirement to ensure that prospective FHA borrowers receive sufficient information to make informed decisions as to indices, based on historical and prospective borrowing costs.

*HUD Response:* HUD agrees that borrowers choosing ARMs, for forward and reverse mortgages, should be provided with sufficient disclosures regarding adjustable rate mortgage products, and will continue to require that lenders provide ARM disclosures prescribed by the Federal Reserve. However, HUD will not require lenders to develop ARM disclosures specific to FHA mortgage insurance programs.

*Comment: Increasing the annual cap to 2 percentage points and a life-of-loan cap of 6 percentage points would benefit consumers.* One commenter wrote that HUD should allow HUD's 5/1 ARM product to be offered with 2/6 caps. The commenter realized that this is current HUD policy, but that FHA sponsors have not yet made these products available.

*HUD Response:* The HUD regulation at 24 CFR 203.49(f)(2) allows for 5-, 7-, and 10 year ARMs to adjust as much as 2 percentage points annually after the initial contract period, and a maximum of 6 percentage points over the life of the loan. HUD makes insured interest rate products such as ARM loans available to the market; however, HUD does not mandate that any lender offer any or all of the ARM products available. Whether or not a lender offers a particular product depends on market demand and other economic factors. For example, in a rising interest rate environment, 2/6 ARMs may not be desirable for borrowers. However, the product requested by the comment is, in fact, legally available.

**V. Findings and Certifications**

*Impact on Small Entities*

The Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*) generally requires an agency to conduct a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements, unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities.

This rule would permit greater flexibility for lenders that, in offering ARMs and HECMs to homebuyers, want to have a choice of indices for determining interest rate adjustments for the ARM and HECM, and for establishing the expected mortgage interest rate on HECM loans. However, this rule would not require any small business to take any action or meet any requirements. Therefore, this rule would create no impact on small entities. Accordingly, the undersigned certifies that this final rule will not have a significant economic impact on a substantial number of small entities, and an initial regulatory flexibility analysis is not required.

*Environmental Impact*

This final rule involves the discretionary establishment of interest rates and external administrative or fiscal requirements or procedures that do not constitute a development decision that affects the physical condition of specific project areas or building sites. Accordingly, under 24 CFR 50.19(c)(6), this rule is categorically excluded from environmental review under the National Environmental Policy Act of 1969 (42 U.S.C. 4321 *et seq.*).

*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 final 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 (UMRA) (2 U.S.C. 1531–1538) establishes requirements for federal agencies to assess the effects of their regulatory actions on state, local, and tribal governments, and the private sector. This final rule would not impose any federal mandates on any state, local, or tribal government, or the private sector within the meaning of UMRA.

*Catalog of Federal Domestic Assistance*

The Catalog of Federal Domestic Assistance number applicable to this rule is 14.175.

**List of Subjects**

*24 CFR Part 203*

Hawaiian Natives, Home improvement, Indians—lands, Loan programs—housing and community development, Mortgage insurance, Reporting and recordkeeping requirements, Solar energy.

*24 CFR Part 206*

Aged, Condominiums, Loan programs—housing and community development, Mortgage insurance, Reporting and recordkeeping requirements.

■ Therefore, for the reasons stated in the preamble, HUD amends 24 CFR parts 203 and 206, as follows:

## PART 203—SINGLE FAMILY MORTGAGE INSURANCE

■ 1. The authority citation for 24 CFR part 203 continues to read as follows:

**Authority:** 12 U.S.C. 1709, 1710, 1715b, 1715z–16, and 1715u; 42 U.S.C. 3535(d).

■ 2. Amend § 203.49 by revising the first sentence of § 203.49(b) to read as follows:

### § 203.49 Eligibility of adjustable rate mortgages.

* * * * *

(b) *Interest rate index.* Changes in the interest rate charged on an adjustable rate mortgage must correspond either to changes in the one-year London Interbank Offered Rate (LIBOR) or to changes in the weekly average yield on U.S. Treasury securities, adjusted to a constant maturity of one year. * * *

* * * * *

## PART 206–HOME EQUITY CONVERSION MORTGAGE INSURANCE

■ 3. The authority citation for 24 CFR part 206 continues to read as follows:

**Authority:** 12 U.S.C. 1715b, 1715z–1720; 42 U.S.C. 3535(d).

■ 4. Amend § 206.3 by revising the definition of ''*Expected average mortgage interest rate*'' and adding, in proper alphabetical order, definitions of ''LIBOR'' and ''One-month Constant Maturity Treasury (CMT) Index'' to read as follows:

### § 206.3 Definitions.

* * * * *

*Expected average mortgage interest rate* means the interest rate used to calculate the principal limit and the future payments to the mortgagor and is established based on the date on which the initial loan application is signed by the borrower. For fixed rate HECMs, it is the fixed mortgage interest rate. For adjustable rate HECMs, it is either the sum of the mortgagee's margin plus the weekly average yield for U.S. Treasury securities adjusted to a constant maturity of 10 years, or it is the sum of the mortgagee's margin plus the 10-year LIBOR swap rate, depending on which interest rate index is chosen by the mortgagor. The margin is determined by the mortgagee and is defined as the amount that is added to the index value to compute the mortgage interest rate. The index type (i.e., CMT or LIBOR) used to calculate the expected average mortgage interest rate must be the same index type used to calculate mortgage interest rate adjustments—commingling of index types is not allowed (e.g., it is not permissible to use the 10-year CMT to determine the expected average mortgage interest rate and use the one-year LIBOR index to adjust the interest rate). The mortgagee's margin is the same margin used to determine the periodic adjustments to the interest rate.

* * * * *

*LIBOR* means the London Interbank Offered Rate.

* * * * *

*One-month Constant Maturity Treasury (CMT) Index* means the average weekly yield of U.S. Treasury securities adjusted to a constant maturity of one month.

* * * * *

■ 5. In § 206.21, revise paragraphs (b)(1) and (b)(2) to read as follows:

### § 206.21 Interest rate.

* * * * *

(b) * * *

(1) A mortgagee offering an adjustable interest rate shall offer a mortgage with an interest rate cap structure that limits the periodic interest rate increases and decreases as provided in § 203.49(a), (b), (d), and (f) of this chapter, except that reference to *mortgagor's first debt service payment* in § 203.49(d) shall mean closing, and references in § 203.49(f)(1) to *one percentage point shall mean two percentage points.*

(2) If a mortgage meeting the requirements of paragraph (b)(1) of this section is offered, the mortgagee may also offer a mortgage which provides for monthly adjustments to the interest rate, corresponding to an index as provided in § 203.49(a), (b), and (f)(1), or to the one-month CMT index or one-month LIBOR index, and which sets a maximum interest rate that can be charged without limiting monthly or annual increases or decreases. The first adjustment must occur on the first day of the second full month after closing.

* * * * *

Dated: July 13, 2007.

**Brian D. Montgomery,**

*Assistant Secretary for Housing—Federal Housing Commissioner.*

[FR Doc. E7–14030 Filed 7–19–07; 8:45 am]

BILLING CODE 4210–67–P

Federal Register

Friday,
July 20, 2007

# Part IV

# The President

## Executive Order 13439—Establishing an Interagency Working Group on Import Safety

Federal Register
Vol. 72, No. 139
Friday, July 20, 2007

# Presidential Documents

**Title 3—**

**The President**

**Executive Order 13439 of July 18, 2007**

## Establishing an Interagency Working Group on Import Safety

By the authority vested in me as President by the Constitution and the laws of the United States of America, and to ensure that the executive branch takes all appropriate steps to promote the safety of imported products, it is hereby ordered as follows:

**Section 1.** *Establishment of Interagency Working Group on Import Safety.* The Secretary of Health and Human Services shall establish within the Department of Health and Human Services for administrative purposes only an Interagency Working Group on Import Safety (Working Group).

**Sec. 2.** *Membership and Operation of Working Group.*

(a) The Working Group shall consist exclusively of the following members, or their designees who shall be officers of the United States appointed by the President or members of the Senior Executive Service:

(i) the Secretary of Health and Human Services, who shall serve as Chair;

(ii) the Secretary of State;

(iii) the Secretary of the Treasury;

(iv) the Attorney General;

(v) the Secretary of Agriculture;

(vi) the Secretary of Commerce;

(vii) the Secretary of Transportation;

(viii) the Secretary of Homeland Security;

(ix) the Director of the Office of Management and Budget;

(x) the United States Trade Representative;

(xi) the Administrator of the Environmental Protection Agency;

(xii) the Chairman of the Consumer Product Safety Commission; and

(xiii) other officers or full-time or permanent part-time employees of the United States, as determined by the Chair, with the concurrence of the head of the department or agency concerned.

(b) The Chair shall convene and preside at meetings of the Working Group, determine its agenda, and direct its work. The Chair may establish and direct subgroups of the Working Group, as appropriate to deal with particular subject matters, that shall consist exclusively of members of the Working Group. The Chair shall designate an officer or employee of the Department of Health and Human Services to serve as the Executive Secretary of the Working Group. The Executive Secretary shall head any staff assigned to the Working Group and any subgroups thereof, and such staff shall consist exclusively of full-time or permanent part-time Federal employees.

**Sec. 3.** *Mission of Working Group.* The mission of the Working Group shall be to identify actions and appropriate steps that can be pursued, within existing resources, to promote the safety of imported products, including the following:

(a) reviewing or assessing current procedures and methods aimed at ensuring the safety of products exported to the United States, including reviewing existing cooperation with foreign governments, foreign manufacturers, and others in the exporting country's private sector regarding their inspection and certification of exported goods and factories producing exported goods and considering whether additional initiatives should be undertaken with respect to exporting countries or companies;

(b) identifying potential means to promote all appropriate steps by U.S. importers to enhance the safety of imported products, including identifying best practices by U.S. importers in selection of foreign manufacturers, inspecting manufacturing facilities, inspecting goods produced on their behalf either before export or before distribution in the United States, identifying origin of products, and safeguarding the supply chain; and

(c) surveying authorities and practices of Federal, State, and local government agencies regarding the safety of imports to identify best practices and enhance coordination among agencies.

**Sec. 4.** *Administration of Working Group.* The Chair shall, to the extent permitted by law, provide administrative support and funding for the Working Group.

**Sec. 5.** *Recommendations of Working Group.* The Working Group shall provide recommendations to the President, through the Assistant to the President for Economic Policy, on the matters set forth in section 3 within 60 days of the date of this order, unless the Chair determines that an extension is necessary. The Working Group may take other actions it considers appropriate to promote the safety of imported products.

**Sec. 6.** *Termination of Working Group.* Following consultation with the Assistant to the President for Economic Policy, the Chair shall terminate the Working Group upon the completion of its duties.

**Sec. 7.** *General Provisions.*

(a) Nothing in this order shall be construed to impair or otherwise affect (i) authority granted by law to a department, agency, or the head thereof, or (ii) functions of the Director of the Office of Management and Budget relating to budget, administrative, or legislative proposals.

(b) This order shall be implemented consistent with applicable law and subject to the availability of appropriations.

(c) This order is not intended to, and does not, create any right, benefit, or privilege, substantive or procedural, enforceable at law or in equity, by any party against the United States, its departments, agencies, or entities, its officers, employees, or agents, or any other person.

THE WHITE HOUSE,
*July 18, 2007.*

[FR Doc. 07–3593
Filed 07–19–07; 10:46 am]
Billing code 3195–01–P

Federal Register

Friday,

July 20, 2007

# Part V

# The President

**Notice of July 19, 2007—Continuation of the National Emergency With Respect to the Former Liberian Regime of Charles Taylor**

Federal Register
Vol. 72, No. 139
Friday, July 20, 2007

# Presidential Documents

**Title 3—**

## The President

**Notice of July 19, 2007**

## Continuation of the National Emergency With Respect to the Former Liberian Regime of Charles Taylor

On July 22, 2004, by Executive Order 13348, I declared a national emergency and ordered related measures, including the blocking of property of certain persons associated with the former Liberian regime of Charles Taylor, pursuant to the International Emergency Economic Powers Act (50 U.S.C. 1701–1706). I took this action to deal with the unusual and extraordinary threat to the foreign policy of the United States constituted by the actions and policies of former Liberian President Charles Taylor and other persons, in particular, their unlawful depletion of Liberian resources and their removal from Liberia and secreting of Liberian funds and property, which have undermined Liberia's transition to democracy and the orderly development of its political, administrative, and economic institutions and resources. I further noted that the Comprehensive Peace Agreement signed on August 18, 2003, and the related cease-fire had not yet been universally implemented throughout Liberia, and that the illicit trade in round logs and timber products was linked to the proliferation of and trafficking in illegal arms, which perpetuated the Liberian conflict and fueled and exacerbated other conflicts throughout West Africa.

Today, Liberia is engaged in a peaceful transition to a democratic order under the administration of President Ellen Johnson-Sirleaf. The regulations implementing Executive Order 13348, clarify that the subject of this national emergency has been and remains limited to the former Liberian regime of Charles Taylor and specified other persons and not the country, citizens, Government, or Central Bank of Liberia.

Charles Taylor is today standing trial in The Hague by the Special Court for Sierra Leone. However, stability in Liberia is still fragile. The actions and policies of Charles Taylor and others have left a legacy of destruction that still has the potential to undermine Liberia's transformation and recovery.

Because the actions and policies of these persons continue to pose an unusual and extraordinary threat to the foreign policy of the United States, the national emergency declared on July 22, 2004, and the measures adopted on that date to deal with that emergency, must continue in effect beyond July 22, 2007. Therefore, in accordance with section 202(d) of the National Emergency Act (50 U.S.C. 1622(d)), I am continuing for 1 year the national emergency declared in Executive Order 13348.

This notice shall be published in the **Federal Register** and transmitted to the Congress.

THE WHITE HOUSE,
*July 19, 2007.*

[FR Doc. 07–3595
Filed 7–19–07; 11:11 am]
Billing code 3195–01–P

# Reader Aids

Federal Register

Vol. 72, No. 139

Friday, July 20, 2007

## CUSTOMER SERVICE AND INFORMATION

| | |
|---|---|
| **Federal Register/Code of Federal Regulations** | |
| General Information, indexes and other finding aids | **202–741–6000** |
| **Laws** | **741–6000** |
| **Presidential Documents** | |
| Executive orders and proclamations | **741–6000** |
| **The United States Government Manual** | **741–6000** |
| **Other Services** | |
| Electronic and on-line services (voice) | **741–6020** |
| Privacy Act Compilation | **741–6064** |
| Public Laws Update Service (numbers, dates, etc.) | **741–6043** |
| TTY for the deaf-and-hard-of-hearing | **741–6086** |

## ELECTRONIC RESEARCH

### World Wide Web

Full text of the daily Federal Register, CFR and other publications is located at: **http://www.gpoaccess.gov/nara/index.html**

Federal Register information and research tools, including Public Inspection List, indexes, and links to GPO Access are located at: **http://www.archives.gov/federal__register**

### E-mail

**FEDREGTOC-L** (Federal Register Table of Contents LISTSERV) is an open e-mail service that provides subscribers with a digital form of the Federal Register Table of Contents. The digital form of the Federal Register Table of Contents includes HTML and PDF links to the full text of each document.

To join or leave, go to **http://listserv.access.gpo.gov** and select *Online mailing list archives, FEDREGTOC-L, Join or leave the list (or change settings);* then follow the instructions.

**PENS** (Public Law Electronic Notification Service) is an e-mail service that notifies subscribers of recently enacted laws.

To subscribe, go to **http://listserv.gsa.gov/archives/publaws-l.html** and select *Join or leave the list (or change settings);* then follow the instructions.

**FEDREGTOC-L** and **PENS** are mailing lists only. We cannot respond to specific inquiries.

**Reference questions.** Send questions and comments about the Federal Register system to: **fedreg.info@nara.gov**

The Federal Register staff cannot interpret specific documents or regulations.

## FEDERAL REGISTER PAGES AND DATE, JULY



## CFR PARTS AFFECTED DURING JULY

At the end of each month, the Office of the Federal Register publishes separately a List of CFR Sections Affected (LSA), which lists parts and sections affected by documents published since the revision date of each title.

## REMINDERS

The items in this list were editorially compiled as an aid to Federal Register users. Inclusion or exclusion from this list has no legal significance.

## RULES GOING INTO EFFECT JULY 20, 2007

**DEFENSE DEPARTMENT**

**Army Department**

Environmental quality:
Environmental protection and enhancement; CFR Part removed; published 7-20-07

**ENERGY DEPARTMENT**

Acquisition regulations:
Management and operating contracts; cooperative audit strategy; implementation; correction; published 7-20-07

**FEDERAL COMMUNICATIONS COMMISSION**

Practice and procedure:
Broadcast Decency Enforcement Act of 2005; implementation—
Obscene, indecent,and profane broadcasts; maximum forfeiture penalties; published 6-20-07

**HEALTH AND HUMAN SERVICES DEPARTMENT**

**Food and Drug Administration**

Color additives:
D&C Black No. 3; published 6-19-07

**NUCLEAR REGULATORY COMMISSION**

Reactor, fuel cycle, and materials licenses, including holders of compliance certificates, registrations, registrations, etc.; annual fees; CFR correction; published 7-20-07

**TREASURY DEPARTMENT**

**Internal Revenue Service**

Income taxes:
Rule requirements of life-nonlife consolidation regulations; published 7-20-07

## RULES GOING INTO EFFECT JULY 21, 2007

**FEDERAL RESERVE SYSTEM**

Availability of funds and collection of checks (Regulation CC):
Routing number guide to next-day availability checks and local checks; reduction of schedules for certain nonlocal checks; technical amendments; published 5-18-07

**HOMELAND SECURITY DEPARTMENT**

**Coast Guard**

Regattas and marine parades:
Port Huron to Mackinac Island Race; published 7-5-07

## COMMENTS DUE NEXT WEEK

**AGRICULTURE DEPARTMENT**

**Agricultural Marketing Service**

Apricots grown in Washington; comments due by 7-23-07; published 7-13-07 [FR E7-13581]

**AGRICULTURE DEPARTMENT**

**Animal and Plant Health Inspection Service**

Plant-related quarantine, domestic:
Citrus canker; comments due by 7-23-07; published 6-21-07 [FR E7-12041]

**AGRICULTURE DEPARTMENT**

**Federal Crop Insurance Corporation**

Crop insurance regulations:
Tobacco crop insurance provisions; comments due by 7-23-07; published 5-23-07 [FR E7-09775]

**ARCHITECTURAL AND TRANSPORTATION BARRIERS COMPLIANCE BOARD**

Americans with Disabilities Act; implementation:
Accessibility guidelines—
Emergency transportable housing Federal advisory committee; intent to establish; comments due by 7-25-07; published 6-25-07 [FR E7-12205]
Passenger Vessel Emergency Alarms Advisory Committee; intent to establish; comments due by 7-25-07; published 6-25-07 [FR E7-12196]

**COMMERCE DEPARTMENT**

**National Oceanic and Atmospheric Administration**

Fishery conservation and management:
Northeastern United States fisheries—
Emergency closure due to presence of toxin causing paralytic shellfish poisoning; comments due by 7-27-07; published 6-27-07 [FR E7-12432]
West Coast States and Western Pacific fisheries—
Highly migratory species; comments due by 7-27-07; published 6-27-07 [FR E7-12430]
International fisheries regulations:
Nations whose fishing vessels are engaged in illegal, unreported, or unregulated fishing or bycatch of protected living marine resources; certification; comments due by 7-26-07; published 6-11-07 [FR E7-11254]
Marine mammals:
Taking and importing—
U.S. Navy operations of surveillance towed array sensor systems low frequency active sonar; comments due by 7-24-07; published 7-9-07 [FR 07-03329]
Ocean and coastal resource management:
Marine sanctuaries—
Channel Islands National Marine Sanctuary, CA; comments due by 7-23-07; published 5-24-07 [FR E7-10096]

**COMMODITY FUTURES TRADING COMMISSION**

Special calls for information; comments due by 7-23-07; published 6-22-07 [FR E7-11984]
Traders reports:
Books and records maintenance; comments due by 7-23-07; published 6-22-07 [FR E7-12045]

**DEFENSE DEPARTMENT**

**Defense Acquisition Regulations System**

Acquisition regulations:
Contract profit/fee policies; comments due by 7-23-07; published 5-22-07 [FR E7-09754]
Leasing; vessels, aircraft, and combat vehicles; comments due by 7-23-07; published 5-22-07 [FR E7-09744]

**DEFENSE DEPARTMENT**

Grants and agreements:
Nonprocurement debarment and suspension; OMB guidance, implementation; comments due by 7-26-07; published 6-26-07 [FR 07-03086]

**EDUCATION DEPARTMENT**

Special education and rehabilitative services:
Infants and Toddlers with Disabilities Early Intervention Program; comments due by 7-23-07; published 5-9-07 [FR 07-02140]

**ENVIRONMENTAL PROTECTION AGENCY**

Air programs; State authority delegations:
Arizona and Nevada; comments due by 7-23-07; published 6-21-07 [FR E7-12044]
Air quality implementation plans:
Preparation, adoption, and submittal—
Interstate ozone transport and nitrogen oxides reduction; petition for reconsideration findings for Georgia; comment request; comments due by 7-23-07; published 6-8-07 [FR E7-11036]
Air quality implementation plans; approval and promulgation; various States:
Delaware; comments due by 7-23-07; published 6-21-07 [FR E7-12051]
Idaho and Washington; comments due by 7-26-07; published 6-26-07 [FR E7-12234]
Iowa; comments due by 7-26-07; published 6-26-07 [FR E7-12237]
Pesticide programs:
Tolerance reassessment decisions—
Methamidophos, etc.; comments due by 7-23-07; published 5-23-07 [FR 07-02561]
Pesticides; tolerances in food, animal feeds, and raw agricultural commodities:
Crop Grouping Program; expansion; comments due by 7-23-07; published 5-23-07 [FR E7-09595]
Famoxadone; comments due by 7-23-07; published 5-23-07 [FR E7-09823]
Propanil, etc.; comments due by 7-23-07; published 5-23-07 [FR E7-09912]

**FEDERAL TRADE COMMISSION**

Industry guides:
Fuel economy advertising for new automobiles;

comments due by 7-23-07; published 5-9-07 [FR E7-08886]
Select leather and imitation leather products; comments due by 7-23-07; published 5-23-07 [FR E7-09965]

**HEALTH AND HUMAN SERVICES DEPARTMENT**

**Centers for Medicare & Medicaid Services**

Medicare:
Medicare Advantage and Part D prescription drug contract determinations, appeals, and intermediate sanctions processes; revisions; comments due by 7-24-07; published 5-25-07 [FR 07-02579]
Prescription drug benefit; policy and technical changes; comments due by 7-24-07; published 5-25-07 [FR 07-02577]

**HEALTH AND HUMAN SERVICES DEPARTMENT**

Privacy Act regulations:
Systems of records exemptions; comments due by 7-24-07; published 5-25-07 [FR E7-10143]

**HOMELAND SECURITY DEPARTMENT**

**Coast Guard**

Anchorage regulations:
Maine; comments due by 7-23-07; published 5-24-07 [FR E7-09968]
Merchant marine officers and seamen:
Large passenger vessels; crew requirements; comments due by 7-23-07; published 4-24-07 [FR E7-07696]
Oceanographic research vessels:
Alternative Compliance Program; comments due by 7-23-07; published 5-22-07 [FR E7-09840]

**INTERIOR DEPARTMENT**

**Land Management Bureau**

Minerals management:
Oil and gas leasing—
National Petroleum Reserve, AK; Federal leases; comments due by 7-23-07; published 5-22-07 [FR E7-09696]

**INTERIOR DEPARTMENT**

**Fish and Wildlife Service**

Endangered and threatened species:
Critical habitat designations—
Marbled murrelet; comments due by 7-26-07; published 6-26-07 [FR 07-03134]

**LABOR DEPARTMENT**

**Employee Benefits Security Administration**

Employee Retirement Income Security Act:
Participants in individual account plans; fee and expense disclosures; comments due by 7-24-07; published 4-25-07 [FR E7-07884]

**SECURITIES AND EXCHANGE COMMISSION**

Securities:
Significant deficiency; definition; comments due by 7-23-07; published 6-27-07 [FR E7-12300]

**TRANSPORTATION DEPARTMENT**

**Federal Aviation Administration**

Airworthiness directives:
Boeing; comments due by 7-23-07; published 5-22-07 [FR E7-09799]
Empresa Brasileira de Aeronautica S.A. (EMBRAER); comments due by 7-25-07; published 6-25-07 [FR E7-12224]
Goodrich; comments due by 7-23-07; published 6-8-07 [FR E7-10992]
Airworthiness standards:
Special conditions—
Adam Aircraft Model A700 airplane; comments due by 7-25-07; published 6-25-07 [FR E7-12121]
Boeing Model 787-8 airplane; comments due by 7-26-07; published 6-11-07 [FR E7-11153]
Boeing Model 787-8 airplane; comments due by 7-26-07; published 6-11-07 [FR E7-11150]
Transport category airplanes—
Airframe ice protection system; activation; comments due by 7-25-07; published 4-26-07 [FR E7-07944]
Class E airspace; comments due by 7-27-07; published 6-27-07 [FR 07-03130]
Jet routes; comments due by 7-23-07; published 6-7-07 [FR E7-11046]

**TREASURY DEPARTMENT**

**Internal Revenue Service**

Estate and gift taxes:
Post-death events; section 2053 guidance; comments due by 7-23-07; published 4-23-07 [FR E7-07601]

**VETERANS AFFAIRS DEPARTMENT**

Compensation, pension, burial, and related benefits:
General provisions; reorganization and revision; comments due by 7-23-07; published 5-22-07 [FR E7-09542]

## LIST OF PUBLIC LAWS

This is a continuing list of public bills from the current session of Congress which have become Federal laws. It may be used in conjunction with ''P L U S'' (Public Laws Update Service) on 202–741–6043. This list is also available online at *http://www.archives.gov/federal-register/laws.html*.

The text of laws is not published in the **Federal Register** but may be ordered in ''slip law'' (individual pamphlet) form from the Superintendent of Documents, U.S. Government Printing Office, Washington, DC 20402 (phone, 202–512–1808). The text will also be made available on the Internet from GPO Access at *http://www.gpoaccess.gov/plaws/index.html*. Some laws may not yet be available.

**S. 1701/P.L. 110–48**

To provide for the extension of transitional medical assistance (TMA) and the abstinence education program through the end of the fiscal year 2007, and for other purposes. (July 18, 2007; 121 Stat. 244; 2 pages)

**Last List July 17, 2007**

## Public Laws Electronic Notification Service (PENS)

**PENS** is a free electronic mail notification service of newly enacted public laws. To subscribe, go to *http://listserv.gsa.gov/archives/publaws-l.html*

**Note:** This service is strictly for E-mail notification of new laws. The text of laws is not available through this service. **PENS** cannot respond to specific inquiries sent to this address.