Federal Register

1–30–04
Vol. 69 No. 20

Friday
Jan. 30, 2004

United States
Government
Printing Office
SUPERINTENDENT
OF DOCUMENTS
Washington, DC 20402

OFFICIAL BUSINESS
Penalty for Private Use, $300

PERIODICALS
Postage and Fees Paid
U.S. Government Printing Office
(ISSN 0097-6326)

*****************3-DIGIT 481
A FR PROQU300P FEB 04 K
PROQUEST
MARY KOERNKE
300 N ZEEB RD
ANN ARBOR MI 48106

Federal Register

1–30–04
Vol. 69 No. 20

Friday
Jan. 30, 2004

Pages 4439–4842

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, *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.access.gpo.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 email 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 $699, or $764 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 $264. Six month subscriptions are available for one-half the annual rate. The charge for individual copies in paper form is $10.00 for each issue, or $10.00 for each group of pages as actually bound; or $2.00 for each issue in microfiche form. All prices include regular domestic postage and handling. International customers please add 40% for foreign handling. 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, *bookstore@gpo.gov*.

How To Cite This Publication: Use the volume number and the page number. Example: 69 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**

What's NEW!

Federal Register Table of Contents via e-mail

Subscribe to FEDREGTOC, to receive the **Federal Register** Table of Contents in your e-mail every day.

If you get the HTML version, you can click directly to any document in the issue.

To subscribe, go to **http://listserv.access.gpo.gov** and select:

Online mailing list archives
FEDREGTOC-L
Join or leave the list

Then follow the instructions.

What's NEW!

Regulations.gov, the award-winning Federal eRulemaking Portal

Regulations.gov is the one-stop U.S. Government web site that makes it easy to participate in the regulatory process.

Try this fast and reliable resource to find all rules published in the *Federal Register* that are currently open for public comment. Submit comments to agencies by filling out a simple web form, or use available email addresses and web sites.

The Regulations.gov e-democracy initiative is brought to you by NARA, GPO, EPA and their eRulemaking partners.

Visit the web site at: **http://www.regulations.gov**

Printed on recycled paper.

Contents

Federal Register

Vol. 69, No. 20

Friday, January 30, 2004

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. 69, No. 20
Friday, January 30, 2004

NUCLEAR REGULATORY COMMISSION

10 CFR Part 50

RIN 3150–AG84

Financial Information Requirements for Applications To Renew or Extend the Term of an Operating License for a Power Reactor

AGENCY: Nuclear Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Nuclear Regulatory Commission (NRC) is amending its regulations to remove the requirement that non-electric utility power reactor licensees submit financial qualifications information in their license renewal applications, and to add a new requirement that electric utility licensees of nuclear power reactors who become non-electric utility entities without a license transfer must notify the NRC and submit information on their financial qualifications. The final rule will reduce unnecessary regulatory burden on licensees seeking renewal of operating licenses and ensure that licensees that become non-electric utility entities continue to be financially qualified to operate their facilities and maintain the public health and safety.

EFFECTIVE DATE: March 1, 2004.

FOR FURTHER INFORMATION CONTACT: George J. Mencinsky, Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001, telephone (301) 415–3093, e-mail *gjm@nrc.gov.*

SUPPLEMENTARY INFORMATION:

Background

Section 182.a. of the Atomic Energy Act of 1954, as amended (AEA), provides that "each application for a license * * * shall specifically state such information as the Commission, by rule or regulation, may determine to be necessary to decide such of the technical and financial qualifications of the applicant * * * as the Commission may deem appropriate for the license." The NRC's regulations governing financial qualifications reviews of applications for licenses to construct or operate nuclear power plants are provided in 10 CFR 50.33(f).

Section 50.33(f)(2), adopted on September 12, 1984 (49 FR 35747), requires all applicants for initial operating licenses and renewal of operating licenses to submit financial qualifications information, except applicants for and holders of operating licenses for nuclear power reactors that are electric utilities. The exception for electric utilities was based on the premise that the cost-of-service ratemaking process ensures that electric utilities will have funds to operate their nuclear power plants safely. Because entities other than electric utilities do not have recourse to such ratemaking, they were required to submit information on financial qualifications in accordance with § 50.33(f), and the NRC was required to make a finding of financial qualification for these non-electric utility entities under § 50.57(a)(4).

In its 1991 License Renewal Rule, 10 CFR part 54 (56 FR 64943; December 13, 1991), the NRC reaffirmed that the basis of the 1984 rulemaking for eliminating financial qualifications reviews for electric utilities applies not only for the term of the original license, but also for the period of operation covered by a renewed license (56 FR at 64968). The License Renewal Rule left unchanged the requirement in § 50.33(f)(2) that license renewal applicants that are not electric utilities must submit financial qualifications information in their renewal applications. However, the section of the License Renewal Rule that contains the standards for issuance of a renewed license, 10 CFR 54.29, does not require a finding regarding financial qualifications for non-electric utility entities applying for license renewal. The revisions to 10 CFR part 54 published on May 8, 1995 (60 FR 22461), did not amend the requirements in 10 CFR 54.29. Thus, while non-electric utility entities are required to submit financial qualifications information under 10 CFR 50.33, there is no requirement under 10 CFR 54.29 for a finding of financial qualifications for non-electric utility entities.

Since the 1995 rulemaking, the NRC has received 40 requests for license renewals and has granted 23 renewed licenses for twelve plant sites to electric utilities. However, because of ongoing deregulation in the power market, new entities other than electric utilities may be created and become licensees of nuclear power plants. Some of these entities may decide to renew their licenses. Under the current rule, these entities would be required to submit financial qualifications information under § 50.33(f)(2).

NRC's case-by-case determination of financial qualifications is resource-intensive and may result in delays in approving renewal applications. The NRC has reviewed the license transfer process to determine if there is a basis in the regulatory process that would eliminate the need for such a finding at license renewal. The NRC determined that, with one exception, it does not need the financial qualifications information from license renewal applicants that are not electric utilities. The exception is when an existing nuclear power licensee transitions from an electric utility to an entity other than an electric utility without transferring its license. All license transfers involving non-electric utility applicants require consideration of the financial qualifications of the non-electric utility entity that holds or will hold the license. However, an electric utility licensee transitioning to a non-electric utility status without a license transfer would not be subject to an NRC review of financial qualifications for the licensee as a non-electric utility entity under current NRC rules. If not closed, this regulatory gap would prevent the NRC from making a generic determination that financial qualifications review is unnecessary at license renewal.

On June 4, 2002, the NRC published a proposed rule in the **Federal Register** (67 FR 38427). The rule proposed to remove the requirement that non-electric utility power reactor licensees submit financial qualifications information in their license renewal applications, and to add a new requirement that licensees of nuclear power reactors who are electric utilities reorganizing as or changing their status to non-electric utility entities without a license transfer must notify the NRC and submit information on their financial qualifications. The proposed rule would reduce unnecessary regulatory burden on licensees seeking renewal of operating licenses and ensure that licensees reorganizing as or changing to non-electric utility entities continue to have financial resources to operate their facilities safely. The public comment period closed on August 19, 2002. Nine comments were received on the proposed rule.

Discussion

After considering public comment, the NRC has decided to adopt the proposed rule unchanged as the final rule. The final rule will remove the requirement that non-electric utility power reactor licensees submit financial qualifications information in their license renewal applications. The final rule will also add a new requirement that licensees of nuclear power reactors who are electric utilities reorganizing as or changing their status to non-electric utility entities without a license transfer must notify the NRC and submit information on their financial qualifications. The final rule reduces unnecessary regulatory burden on licensees seeking renewal of operating licenses and ensures that licensees reorganizing as or changing to non-electric utility entities continue to be financially qualified to operate their facilities and maintain the public health and safety. These changes will increase regulatory clarity and strengthen the NRC's ability to protect public health and safety. The following discussion presents the basis and rationale for this action.

The NRC's regulations provide for an evaluation of the financial qualifications of an applicant for a nuclear power reactor operating license or a licensee at several points during a reactor's operating lifetime—at initial licensing, before license transfers, and when circumstances warrant an ad hoc request for additional financial information. In addition, the NRC monitors the financial trade press and other sources for information on licensees' financial situations.

Currently, there is one gap in the NRC's regulatory provisions for evaluating a power reactor licensee's financial qualifications. The NRC's current regulations do not require a financial qualifications review when a licensee transitions from an electric utility to an entity other than an electric utility without transferring control of its license. This final rule will rectify the regulatory gap by imposing a requirement that these licensees submit financial qualifications information to the NRC. With the addition of this provision, the NRC believes it has a basis for concluding that non-electric utility licensees that are holders of operating licenses for nuclear power reactors need not submit financial qualifications information during the license renewal process.

With this final rule, the NRC believes that review of financial qualifications of non-electric utility licensee applicants at license renewal is not necessary. The resulting process for oversight of financial qualifications is sufficient to ensure that the NRC has adequate warning of adverse financial impacts so that the NRC can take timely regulatory action to ensure public health and safety and the common defense and security. The resulting process has two components: (1) A formal review of major triggering events, and (2) monitoring of financial health between the formal reviews due at the "triggering events." The relevant triggering events are (1) initial operating license application, (2) license transfer, and (3) transition from an electric utility to a non-electric utility, either with or without transfer of control of the license. In addition, the NRC can review a licensee's financial qualifications at any point during the term of the license if there is evidence of a decline in the licensee's financial health. The NRC believes that there are no unique financial circumstances associated with license renewal because the NRC has no information indicating a licensee's revenues and expenses change due to license renewal.

Between major triggering events, the NRC relies upon periodic monitoring of the financial health of licensees to detect whether additional regulatory scrutiny and action are necessary to assure public health and safety and the common defense and security. The NRC's current regulations require non-electric utility reactor licensees to submit 5 years of financial projections for license renewal applications. Because this financial qualifications information ages quickly and is of limited relevance years later, the NRC relies on a process of monitoring licensees throughout the term of their licenses for any indications that they may not have sufficient financial resources to operate their plants safely.

The current licensee monitoring process involves the review of financial and industry trade press as well as other publicly available information, such as Securities and Exchange Commission (SEC) submissions and Federal Energy Regulatory Commission (FERC) submissions. The NRC reviews this information to identify changes in licensees' financial health, as well as indirect indicators of declining financial health such as layoffs or increasing technical problems. If the review of any of these sources indicates that a licensee's financial health may be deteriorating, the NRC can request additional financial information from the licensee as authorized by 10 CFR 50.33(f)(4) to confirm that a licensee has the financial resources to operate the facility safely. The financial information that the NRC can request under 10 CFR 50.33(f)(4) can be the same type of information required for an initial license application or a license transfer.

The following sections discuss the times in a licensee's term of license when financial qualifications are reviewed and the changes made by this final rule.

Initial Licensing Reviews

The NRC performs financial qualifications reviews during initial licensing because the startup of a nuclear power reactor is a major financial undertaking that has significant implications for a company's financial health. The NRC's financial qualifications review process is contained in NUREG–1577, "Standard Review Plan on Power Reactor Licensee Financial Qualifications and Decommissioning Funding Assurance," March 1999. These reviews form part of the licensing basis that the licensee must maintain for the 40-year term of the initial license and for any license renewal period. Financial qualifications reviews at the operating license stage distinguish between license applicants that are electric utilities, as defined in 10 CFR 50.2, and those that are not. Applicants other than electric utilities are required to submit estimates for total annual operating costs for each of the first 5 years of operation of the facility and to indicate the sources of funds to cover these costs. The NRC's evaluation of the financial qualifications of an entity other than an electric utility applicant is based on the submitted 5-year projections of income and expenses. In addition, the NRC considers current information from several major financial rating service publications, and other relevant information, may also be considered. As part of its evaluation, the NRC reviews the reasonableness of an applicant's assumptions and inputs to its projections. The NRC publishes the results of its evaluation in a safety evaluation report. The NRC's regulations do not require additional financial qualifications reviews at scheduled intervals.

License Transfer Reviews

The NRC reviews financial qualifications during direct license transfers because a new licensee must be qualified to hold the license. A plant acquisition or the indirect transfer of a license through a transfer of control of a licensee can have significant implications for a licensee's financial health. A license transfer under 10 CFR 50.80 may occur at any time during the period of the license. The NRC reviews the financial qualifications of non-electric utility applicants seeking to become licensees through direct license transfers (plant sales), and considers changes in the financial qualifications of an existing licensee, whether or not it is an electric utility, that might occur in connection with an indirect license transfer occurring in connection with a merger, acquisition, or restructuring action. For license transfers, a non-electric utility applicant must submit all the information required under § 50.33(f). As with initial license financial qualifications reviews, the NRC uses NUREG–1577 as the basis for its review and publishes the results of its evaluation in a safety evaluation report. The NRC has performed financial qualifications reviews on over 75 license transfer applications in the last 5 years. The NRC expects that it will continue to review numerous licensees' financial qualifications in the next few years because of license transfers.

Reviews of Transition From an Electric Utility to a Non-Electric Utility

The NRC will review financial qualifications when an electric utility licensee transitions to non-electric utility status without a license transfer because a licensee is no longer ensured the recovery of its costs through traditional cost-of-service rate regulation. Before this final rule, the NRC had no formal automatic process to evaluate the licensee's financial qualifications if such a transition occurred in the absence of a license transfer (although the NRC's monitoring process should identify such transitions and could trigger a request for additional information pursuant to § 50.33(f)(4)). Therefore, the NRC is promulgating 10 CFR 50.76, a requirement separate from § 50.33(f)(2). Section 50.76 requires licensees that are transitioning from an electric utility to non-electric utility status, without being required to request approval for license transfers, to submit financial information sufficient to allow the NRC to determine whether the licensee remains financially qualified to conduct the activities authorized by the license. Although the NRC expects that this type of transition will occur rarely, if at all, this requirement will ensure that a financial qualifications review for non-electric utilities results from all relevant triggering events, thereby enhancing public confidence while maintaining regulatory efficiency and effectiveness. The relevant triggering events are (1) initial operating license application, (2) license transfer, and (3) transition from an electric utility to non-electric utility status without a license transfer.

Section 50.76 is created separately from § 50.33, because the latter section focuses on applicants rather than licensees.

Screening of Financial and Nuclear Industry Trade Press and Other Information Sources

To keep abreast of deregulation and other developments potentially affecting power reactor licensees, the NRC regularly screens the financial and trade press (*e.g.*, Wall Street Journal, Barron's, Nuclear NewsLink, and Nuclear Energy Insight). Other information sources (*e.g.*, State legislative reports, SEC and FERC submissions) also can be used. The NRC uses the foregoing to identify changes in licensees' financial health. A main purpose of this information review is to provide NRC with sufficient notification so that it can take regulatory action in a timely manner, when necessary. The NRC can then request additional information from licensees under § 50.33(f)(4).

Section 50.33(f)(4) states:

> The Commission may request an established entity or newly formed entity to submit additional or more detailed information respecting its financial arrangements and status of funds if the Commission considers this information to be appropriate. This may include information regarding a licensee's ability to continue the conduct of the activities authorized by the license and to decommission the facility.

This section permits the NRC to require license applicants or licensees to submit relevant financial information on their qualifications to manage licensed activities safely at any time. The requested additional information can then be used to conduct a thorough financial qualifications review.

Retention of Nonpower Reactor Financial Reviews at License Renewal

The NRC will retain the financial qualifications requirements in § 50.33(f)(2) for nonpower reactor (NPR) applicants that wish to renew or extend their licenses. There are currently 37 nonpower reactor licensees. Nonpower reactor licenses are generally renewed for 20 years. The NRC does not normally follow changes in NPR licensee financial qualifications because NPR owners are primarily financially stable nonprofit educational or research institutions, either privately owned (3 corporate licensees and 28 academic licensees), State-owned (1 licensee), or Federally owned (5 licensees), and generally do not report financial information to sources readily available to the NRC. The limited publicly available reporting from these types of owners does not permit the same level of ongoing financial qualifications oversight as with power reactor licensees. Additionally, license transfers for NPRs and the associated financial reviews are rare. Given these factors, financial qualification problems with NPR licensees are not as likely to become known as problems with power reactor licensees. In some cases, the NRC has found financial weaknesses or ambiguities during NPR license renewals that it would not have discovered otherwise. Therefore, the NRC considers it appropriate to continue to review the financial qualifications of NPR licensees when they apply to renew their licenses.

Conclusion

Section 50.33(f) requires all non-electric utility applicants for initial and renewed operating licenses, and § 50.80, in conjunction with § 50.33(f), requires all non-electric utility applicants for transferred licenses, to submit financial qualifications information. The NRC does not believe that there are any financial circumstances uniquely associated with license renewal that warrant a separate financial review. The NRC's regulatory processes for financial qualifications reviews adequately ensure that the NRC can take appropriate and timely regulatory action when warranted by changes in a licensee's financial qualifications. In contrast, there are valid regulatory reasons for conducting specified financial qualifications reviews at other license stages. The license stages are (1) at initial licensing, when an applicant's financial qualifications need to be determined in accordance with the AEA's requirements; (2) at the time of a license transfer, when new licensees need to be evaluated, or when deregulation initiatives may affect an applicant's or licensee's financial qualifications; or (3) during special circumstances, when ad hoc reviews under § 50.33(f)(4) may be warranted.

As a result, the NRC is promulgating a change in the requirement in the last sentence of § 50.33(f)(2) with respect to entities other than electric utilities seeking renewal of operating licenses for nuclear power reactors. The final rule (1) eliminates the need for such entities to provide financial qualifications information as part of the license renewal process, (2) retains the existing requirement in § 50.33(f) for nonpower reactors to provide financial qualifications information, and (3) adds a new § 50.76, "Licensee's change of status; financial qualifications." Section 50.76 will require that any electric utility power reactor licensee that becomes an entity other than an electric utility without transferring control of the license must provide the same financial information that is required for obtaining an initial operating license. The final rule will not affect the submission of financial qualifications information and the need for a finding of financial qualifications to the extent presently required for license transfers.

The NRC believes this final rule is consistent with the NRC's Strategic Goals of making NRC activities and decisions more effective and efficient and reducing unnecessary regulatory burden. The final rule will help advance these goals by eliminating the need for "entities other than electric utilities" to submit information on financial qualifications (as is the case now for electric utilities) in connection with license renewal, and will make the financial qualifications review requirements consistent with the bases of the License Renewal Rule in 10 CFR part 54, which does not require a finding of financial qualifications for those power reactor licensees applying for a renewed nuclear power plant operating license. The final rule will not have an adverse impact on maintaining safety. The provisions in § 50.33(f)(4) already ensure that financial information can be obtained from a licensee whenever the NRC considers this information appropriate.

Resolution of Public Comments

The NRC received comments on the proposed rule from nine different organizations, including one State, three nonprofits, and five organizations in the nuclear power industry. Five commenters opposed the changes to § 50.33 and four commenters supported the changes to § 50.33. Two commenters opposed adding the new § 50.76, three commenters supported this change, and four commenters were silent on the creation of the new § 50.76. After considering the public comments, the NRC has decided to adopt the proposed rule on "Financial Information Requirements for Applications To Renew or Extend the Term of an Operating License for a Power Reactor" as final without changes. A summary of the comments and the NRC's responses follows:

Comment 1: Four commenters support the NRC's proposed revisions to 10 CFR 50.33 to eliminate the requirement that non-electric utility power reactor licensees submit financial qualifications information during license renewal. One commenter agrees with the NRC's assessment that there are no unique financial circumstances associated with license renewal that warrant a separate financial review.

Response: No response necessary.

Comment 2: Two commenters agree with the proposal to add a requirement in 10 CFR 50.76 that electric utilities that transition to non-electric utility status without a license transfer should submit financial qualifications information.

Response: No response necessary.

Comment 3: Five commenters oppose the NRC's proposal to eliminate submission of financial qualifications information for non-electric utilities during license renewal. One commenter expresses concern that the changes to 10 CFR 50.33 would weaken protection of public safety. Another commenter states that eliminating this requirement will create an "information vacuum" that will place the NRC in a state of ignorance.

Response: The NRC disagrees that the changes to 10 CFR 50.33 will weaken protection of public health and safety or deprive the NRC of necessary information. The NRC's license transfer reviews have provided the NRC with financial information on current non-electric utility licensees, and will continue to do so for future license transfers. Moreover, the NRC's current process for monitoring the financial health of licensees, as previously described, is effective in ensuring that licensees have adequate financial resources to operate their facilities safely and provides sufficient information to allow the NRC to take timely regulatory action if a licensee's financial health deteriorates.

The commenter implies that the changes to 10 CFR 50.33 will allow financially weak licensees to continue to operate. The changes to 10 CFR 50.33 relate to when NRC reviews the financial status of licensees, not necessarily whether the licensee should continue to operate. The NRC believes that its primary tool for evaluating and ensuring safe operations at nuclear power reactors is through its inspection and enforcement programs, which are not affected by this rulemaking.

Comment 4: Two commenters are concerned that in the wake of recent corporate financial and accounting scandals, the NRC is considering relaxing its financial oversight of non-electric utility power reactor licensees. One commenter also states that Congress has acknowledged the need for more stringent oversight of corporate accounting and that the NRC's actions are incompatible with Congress's findings.

Response: The NRC disagrees with the commenters that this action is incompatible with recent experience or Congress's findings about the need for careful oversight. The NRC's purposes and responsibilities are different from agencies, such as the Securities and Exchange Commission (SEC), that are responsible for oversight of companies with respect to accounting or financial reporting improprieties. The NRC has no regulatory authority over corporate accounting methods. This action in no way relaxes the NRC's regulations that require all part 50 applications to be submitted under oath and affirmation (*see* 10 CFR 50.30) and that require all information submitted to be complete and accurate in all material respects (*see* 10 CFR 50.9). The NRC continues to possess the authority to impose sanctions for the submission of incomplete or inaccurate information. The NRC does not believe that this action has any relationship to recent financial reporting and accounting issues cited by the commenters.

Comment 5: One commenter states that in a U.S. General Accounting Office (GAO) report on the Commonwealth Edison and PECO merger, GAO pointed out that the NRC did not validate submitted information and the NRC approved the license transfers associated with the merger knowing that submitted pro forma financial information was inaccurate.

Response: The comment addresses whether information submitted to the NRC for a financial qualifications review is verified for accuracy and whether the NRC takes licensing actions based on information known to be inaccurate. The NRC's response to the GAO findings, with which the NRC disagreed, is contained in the GAO report. With respect to this rulemaking, however, which deals with the timing of a financial qualifications review, the comment does not pertain to whether a financial qualifications review specifically during license renewal is necessary, and, therefore, the comment is not relevant.

Comment 6: One commenter cites an NRC document (NUREG/CR–6617, October 1998) that suggests the NRC believes the financial health of power reactor licensees may suffer from deregulation. According to one commenter, the document suggests that the economic pressures in a deregulated environment might hasten the closure of some power reactors. The commenter asserts that the fact that the NRC now believes that financial qualifications reviews are not necessary during license renewal is incompatible with the earlier findings.

Response: The NRC disagrees that this action is incompatible with the information in NUREG/CR–6617. The NRC is concerned with assuring that operating reactors are operated safely. If financial circumstances force reactors to cease operation, the NRC has other requirements in place with respect to decommissioning funds that provide reasonable assurance that a prematurely shutdown reactor is decommissioned and does not pose a public health and safety risk. The NRC's licensee monitoring process, as previously described, will provide adequate warning to ensure that the NRC can respond with timely regulatory action if a licensee's financial health suffers from deregulation. The license renewal application event has no particular bearing on a licensee's financial qualifications. If anything, undertaking to renew a license suggests that the licensee is projecting future profitability by continuing to operate the plant beyond its original operating license.

Comment 7: Three commenters are concerned that the NRC's reliance on trade press information is inadequate to track the financial health of non-electric utilities. One commenter states that since power reactor licensees operate in a competitive environment, they generally do not disclose financial information unless required to do so. The commenter states that as a minority owner of two power reactors, it has difficulty monitoring the financial qualifications of the plant operators. In addition, since power reactor licensees are generally organized as part of a complex holding company system, the trade press does not have sufficient information to report at a level below the holding company as a whole. One commenter states that the day-to-day informal monitoring of the trade press and limited annual reviews are not substitutes for a formal, rigorous, and disciplined review of a licensee's financial qualifications at license renewal.

Response: The NRC disagrees with the commenter's views that the NRC's processes are inadequate to monitor the financial health of non-electric utilities. As previously described, the NRC not only relies upon the trade press and licensee filings with other government agencies, it also has the benefit of having onsite inspectors who may become aware of relevant information. Moreover, the NRC has the authority to request additional financial information directly from licensees at any time under 10 CFR 50.33(f)(4).

Monitoring the trade press is a common practice in the financial and investment community to screen the financial and business conditions of any business activity or entity. The NRC believes that its ongoing licensee financial monitoring process is necessary and is a better use of the NRC's resources than a formal financial qualifications review at license renewal because license renewal occurs at an arbitrary point in time during a licensee's operating license. On average, power reactor licensees apply for license renewal 14 years before their initial license expires. Thus the 5 years of projected operating expenses and revenues that non-electric utility power reactors are currently required to submit do not include the period to be covered by the renewed license. Therefore the information submitted is of limited value to the NRC in determining if the licensee will have adequate financial qualifications in the period to be covered by the renewed license.

The NRC does not agree that the situation of a minority owner with respect to financial information is the same as the situation of the NRC. The NRC possesses regulatory authority under § 50.33(f)(4) to obtain additional financial information from licensees at any time that is necessary to determine whether a licensee continues to be financially qualified.

Comment 8: One commenter states that the aging of power reactors requires more, not less, financial oversight. The commenter cites the examples of corrosion in the reactor vessel head at the Davis-Besse reactor and cracking of reactor pressure vessel head penetration nozzles in pressurized water reactors. The commenter also states that as reactors age, licensees have conflicting demands of keeping the reactors operating and temporarily shutting them down to make necessary inspections and repairs. Licensees in poor financial health may be more likely to postpone these inspections and repairs, increasing the likelihood of an accident.

Response: The NRC disagrees with the commenter. The rule eliminates the burden of the unnecessary financial review so that the NRC can focus more resources on the technical aspects of power reactor license renewal. The Davis-Besse example cited by the commenter is principally a technical issue. Moreover, there does not appear to be any information available to the NRC that suggests that the Davis-Besse situation was caused by a deterioration in the financial health of the licensee, and the commenter does not present any information today to show such a causal link. The NRC has not found a consistent correlation between licensees' poor financial health and poor safety performance. If a licensee postpones inspections and repairs that are subject to NRC oversight, the NRC has the authority to shut down the reactor or take other appropriate action if there is a safety issue.

Comment 9: Three commenters are concerned that non-electric utility power reactor licensees are organized as single-asset limited liability companies (LLCs), which they assert are designed to limit the liability of the parent companies in the event of the financial failure of the LLC and to shield the power reactor licensee from public scrutiny of its finances. One commenter states that, in some cases, the LLCs are foreign companies or exist only on paper. Another commenter states that a recent report shows that 25 power reactors are owned by LLCs. Another commenter states that the selection of the limited liability structure indicates that these owners recognize that their financial health is subject to substantial change. Because financial well-being is essential for power reactor licensees, this structure also signals a significant risk to the health and safety of the public.

Response: While LLCs provide limits on the liability of parent organizations, the same is true for traditional corporations that have parent companies. Regardless of whether a power reactor licensee is an LLC or another corporate form such as a wholly owned corporate subsidiary, the NRC has essentially the same opportunity to obtain relevant financial information about the licensee. The NRC may request and review, on a case-by-case basis, relevant financial information from the LLC licensee as authorized under 10 CFR 50.33(f)(4).

The NRC does not agree with the commenter's view that the use of the LLC structure indicates licensees anticipate substantial changes in financial health and signals significant risk to the health and safety of the public. The Commission retains the same enforcement and inspection authority regardless of the corporate structure and can ultimately shut any reactors down if they are not operated safely.

Comment 10: Two commenters state that because non-electric utility licensees lack the assured base of funding of electric utility licensees, they increase the risk that there will be insufficient capital resources to operate the power reactor safely, as the non-electric utility licensees diversify into telecommunications, commodity and energy trading, high-risk financial activities, or other activities.

Response: The NRC disagrees with the commenters. The NRC has long determined that non-electric utilities can be licensed regardless of the fact that they do not have an assured base of funding. In this regard, the NRC has a full regulatory regime for licensing non-electric utilities that requires substantial financial information be submitted and reviewed, which is not the case for licensing reviews for electric utilities. In addition, the NRC has no basis for concluding that diversification will always threaten the financial well being of non-electric utility power reactor licensees.

Comment 11: One commenter states that disclosure and transparency to regulators is essential for ensuring that the NRC is not caught unaware of a deteriorating financial condition. Given the lack of transparency in the structures and finances of many publicly traded energy companies, the NRC seems out of step with the widely agreed-upon need for increased corporate disclosure.

Response: The NRC agrees that the NRC needs to be aware of changes in the financial condition of licensees and therefore, continues to monitor licensees' financial health. The NRC does not believe that the action being taken is somehow "out of step" with the "need for increased corporate disclosure" or inconsistent with the NRC's ability to obtain relevant corporate financial information. This action only removes one requirement to provide certain financial information at one point in time; it does not affect in any way the NRC's ability to require the submission of additional or more detailed financial information at any time the NRC needs such information.

Comment 12: One commenter believes that the NRC's current review of financial qualifications at initial licensing, before license transfers, and on an ad hoc basis is not adequate. The commenter states that the financial qualifications of a licensee at either initial licensing or at license transfer may have little relevance to the licensee's financial qualifications many years later when license renewal is sought. Because of our dynamic economy, a company's financial status can change significantly in a matter of months and thus several-year-old financial information is worthless.

Response: The commenter essentially is questioning the entire NRC financial qualifications regulatory process because the argument that financial information quickly becomes stale applies whether or not there is any decision to renew a license. The NRC agrees with the commenter that financial qualifications information eventually becomes out of date and is no longer relevant after the passage of time. That is the reason why the NRC has a two-pronged process for financial qualifications, with the second prong being continued monitoring of the financial health of licensees. This process provides a reasonable method to keep abreast of licensees' financial health to ensure sufficient financial resources are available to continue safe operation of nuclear power plants, as well as decommissioning plants when they permanently cease operation. For power reactor licensees, financial qualifications reviews at license renewal, which takes place at an arbitrary point in time, do not solve the problem raised by the commenter.

Comment 13: Three commenters state that license renewal is a particularly appropriate time to evaluate the financial requirements of power reactor licensees. The commenters state that non-electric utility power reactor licensee financial qualifications should be evaluated to ensure that there are sufficient financial resources to continue safe operation, make capital improvements, add spent fuel storage capacity, meet additional licensing conditions imposed because of September 11, 2001, events, meet decommissioning obligation, and meet public liability obligations under the Price-Anderson Act, in light of the economic conditions at the time of renewal.

Response: The NRC disagrees with the commenters' view that license renewal is a particularly appropriate time for a financial qualifications review given that it is just one point in time over potentially 60 years of plant operation. The NRC's process for regular monitoring of power reactor licensees meets the need to know whether licensees may not have sufficient financial qualifications and allows for adequate warning so that the NRC can request financial qualifications information and take regulatory action in a timely manner if necessary. With respect to the scope of financial qualifications analyses, the NRC is not proposing any changes to its financial qualifications analyses through this action.

Comment 14: One commenter states that the same rationale used for maintaining the requirement for nonpower reactor licensees to submit financial qualifications information during license renewal applies to non-electric utility power reactors. The commenter notes that the NRC states in the proposed rule (67 FR 38429) that it has found financial weaknesses or other ambiguities during the review of nonpower reactor licensees' financial information in the license renewal process that it would not have discovered otherwise. The commenter states further that given the lack of information in the trade press about non-electric utility power reactors and because of the use of LLCs, a formal review process at the time of license renewal may disclose financial weaknesses that otherwise would not be discovered.

Response: The NRC disagrees that the same rationale used for nonpower reactor licensees applies to non-electric utility power reactor licensees. There are many nonpower reactor licensees that are nonprofit educational or research institutions, with either private, State, or Federal ownership, that do not report financial information to sources readily available to the NRC. Thus the NRC is not as able to monitor the financial health of these organizations on an ongoing basis. In addition, many nonpower reactor licensees are multipurpose, non-revenue-generating entities that require outside funding for financial support and thus are economically more risky. Accordingly, the NRC will continue to perform financial qualifications reviews as part of the renewal of nonpower reactor licensees, which typically occurs every 20 years. On the other hand, power reactor licensees are single-purpose, revenue-generating entities. Therefore, the NRC is able to review non-electric utility power reactor licensee financial information more readily on an ongoing basis.

Comment 15: One commenter states that the NRC should establish a more rigorous financial monitoring system that includes an annual review by the NRC of licensees' account books. The commenter states that the NRC needs to know the financial status of non-electric utility power reactor licensees before the information is published in the trade press.

Response: The NRC disagrees with the comment. The extensive annual financial audit process that the commenter suggests is not necessary for the NRC to achieve its oversight of licensees under the Atomic Energy Act and to ensure public health and safety and promote the common defense and security. Nor is it clear why the NRC must know the financial status of non-electric utility licensees before information on their financial health is published in the trade press. The NRC's regulations require that all part 50 applications be submitted under oath and affirmation (*see* 10 CFR 50.30) and that all information submitted must be complete and accurate in all material respects (see 10 CFR 50.9). The NRC also possesses the authority to impose sanctions for incomplete or inaccurate information and, of course, possesses the authority to take action necessary to ensure the safe operation of nuclear facilities. For these reasons, the NRC believes its regulatory process and its financial monitoring system are adequate and sufficient to meet these goals.

Comment 16: One commenter states that the Regulatory Analysis disregards the value to the public health and safety of reviewing a non-electric utility power reactor licensee's financial qualifications at the time of license renewal.

Response: The NRC disagrees with the commenter that the Regulatory Analysis disregarded the value to public health and safety of review of financial qualifications at the time of license renewal. The financial qualifications review for power reactor relicensing occurs at an arbitrary point in time that has no distinct link to public health and safety. Public health and safety are primarily protected through the NRC's onsite inspection program, and the financial health of a licensee is verified through NRC's monitoring of publicly available financial information.

Comment 17: One commenter states that the NRC is not sufficiently independent of the industry that it regulates. The commenter mentions that the NRC has stated that case-by-case review of financial qualifications information might delay the approval of a license application. The commenter suggests this gives the impression that the NRC believes its duty is to approve renewal applications and not to thoroughly review and analyze them prior to accepting or rejecting applications. The commenter concludes that the license renewal process should be a truly rigorous process and not simply a rubber-stamping formality.

Response: The NRC disagrees with the comment that NRC is not sufficiently independent of the industry. The NRC is a fully independent regulator of the nuclear power industry. No licensing application's approval is a foregone conclusion. The NRC will continually conduct technical reviews until the licensee has performed all necessary actions as required in the regulations before approving a license application. No licensing action is approved until all technical issues have been addressed. The NRC's commitment to thorough review and analysis of license renewal applications is reflected in the staff time to review those applications, which is on the order of 19,000 person-hours per application.

Nonetheless, to be an effective regulator, the NRC must also conduct its regulatory activities in protecting public health and safety and the common defense and security in a manner that is efficient and does not impose unnecessary regulatory burdens. This final rulemaking is directed towards ensuring that the NRC carries out its regulatory responsibilities in an efficient and cost-effective manner.

Comment 18: One commenter stated that the proposed regulatory language in § 50.76 is open ended and could cause confusion at the end of the 75-day period. The commenter suggested the following language should be added: "Financial qualifications information submitted in accordance with this section shall be regarded as accepted by the Commission upon receipt of a letter to this effect from the appropriate reviewing office of the Commission or 75 days after the submittal to the Commission, whichever occurs first."

Response: The NRC disagrees with the proposed addition. The NRC believes that the regulatory language is clear that information must be submitted no later than 75 days before an electric utility licensee ceases to be an electric utility. The commenter's proposal would change the regulation and require the NRC to take action within 75 days.

Comment 19: Two commenters disagree that there is a regulatory gap that must be filled by the addition of 10 CFR 50.76. One commenter states that the NRC has sufficient existing authority under 10 CFR 50.33(f)(4) to require applicants or licensees to submit financial qualifications information. In addition, licensees have an obligation to inform and obtain approval from the NRC for any changes that would constitute a transfer of license, and licensees must promptly report financial qualifications information that may have a significant implication for public health and safety. Therefore, the commenter believes the new requirement is unnecessary and unjustified. One commenter believes the new requirement is unnecessary and unwarranted and that the gap is perceived and not real since no problems were cited by the NRC. Thus, the new requirement is not necessary and would create only unnecessary burden with no benefit.

Response: The NRC disagrees with the commenters regarding the absence of a regulatory gap. The NRC believes that the transition from an electric utility to a non-electric utility is a significant event that requires regulatory review to ensure continued financial qualifications of the licensee lacking assured cost recovery. The fact that the NRC has authority to request financial qualification information is of no relevance in determining whether there is a regulatory gap. In the NRC's view, the regulatory gap exists because the current regulatory regime does not compel that the NRC be timely informed of changes in a licensee's cost recovery status when there is no license transfer. Because such notification would, in all likelihood, be followed by an NRC request for information, the final rule simply provides that electric utility licensees transitioning to non-electric utility status without a license transfer must provide the relevant financial qualifications information. The NRC also disagrees that the regulatory gap is only perceived because no problems have occurred to date. The lack of examples of problems does not support the conclusion that a regulatory gap does not exist. With this regulation, the NRC is being proactive and is attempting to prevent problems from occurring.

Comment 20: One commenter opposes the addition of 10 CFR 50.76 and states that the proposed rule would impose unnecessary regulatory costs due to collecting and submitting financial qualifications information and that this added burden may impact licensees' business decisions about whether to seek license renewals.

Response: The NRC disagrees with the commenter that the creation of 10 CFR 50.76 is unnecessary. The NRC strives to ensure that its regulations meet real regulatory needs and that unnecessary regulations are avoided. Consistent with this objective, the NRC believes that the proposed action is necessary to ensure NRC fulfils its regulatory responsibilities under the Atomic Energy Act. This change complements the existing regulations requiring power reactor licensees to submit financial qualifications information when they become non-electric utilities during a transfer of control of a license. Thus, under the final rule all licensees that transition from electric utilities to non-electric utilities will undergo financial qualifications review, regardless of whether the transition involves the transfer of control of an NRC license. Nor does the NRC believe that the cost of collecting and submitting the information to the NRC (see Regulatory

Analysis for a discussion of the projected costs of compliance with the final rule) will affect a licensee's decision on whether to seek renewal of its operating license in any material way.

Comment 21: One commenter states that the new requirement at 10 CFR 50.76 is unnecessary because (1) licensees have an obligation to inform, and obtain advanced approval from, the NRC of any changes that would constitute a transfer of the license, directly or indirectly, (2) licensees have an obligation to inform the NRC if changes in their financial qualifications may have significant implications for public health and safety, and (3) the NRC monitors the financial and industry trade press.

Response: The NRC disagrees with the commenter that the creation of 10 CFR 50.76 is unnecessary. Licensees' obligation to inform and obtain prior NRC approval of a license transfer is separate from the issue of the need for licensee notification and provision of information about financial qualifications when a licensee changes its status from an electric utility to a non-electric utility without an associated transfer of control of the license. Although licensees have an obligation to report significant changes in their financial qualifications, it is possible that some licensees could believe that they will remain financially qualified notwithstanding their change in status from an electric utility to a non-electric utility and thus not consider that event to be a reportable change in financial qualifications. Furthermore, while the NRC monitors the financial and industry trade press, the NRC believes that a licensee transition from electric utility to non-electric utility status is a significant event that automatically warrants a separate financial qualifications review. This type of review already occurs when the transition is associated with a license transfer. Section 50.76 would simply ensure that financial qualification reviews occur as part of a transition from an electric utility to non-electric utility status without a license transfer.

Comment 22: One commenter states that the new section creates additional regulatory issues and burdens without any corresponding safety benefit. A complicating issue that might arise is determining precisely what types of changes would cause a licensee to cease being an electric utility. The NRC and the licensee may disagree that a triggering event has occurred. If so the licensee may not notify the NRC before the 75-day deadline.

Response: The NRC disagrees with the commenter that the new section creates additional regulatory issues and burdens without any corresponding benefit. The benefit of this action is ensuring on at least one occasion that a licensee who transitions from electric utility to non-electric utility status without a license transfer will continue to have the resources necessary to operate the power plant in a manner that protects public health and safety and is consistent with the common defense and security.

With respect to disagreement on what constitutes a transition from electric utility to non-electric utility status, the commenter did not provide any discussion of such circumstances. The NRC is unaware of any significant misunderstandings of what constitutes an electric utility under 10 CFR 50.2. Therefore, the commenter does not appear to raise a significant issue.

Comment 23: One commenter suggests that, instead of the proposed regulatory changes, the NRC should update the definition of "electric utility" in 10 CFR 50.2 to reflect the changes that have occurred in the electric utility industry. For example, the definition should provide flexibility to include utilities that may no longer be subject to cost of service rate making. The commenter also suggests that the definition should be flexible enough to include entities other than traditional vertically integrated utilities, such as those that have desegregated their business into generating and transmission/distribution entities. The commenter concludes that the definition of electric utility should include (1) a generating company that is part of a diversified holding company or other corporate structure and (2) an entity that generates and sells electricity at market-based rates, at least so long as the company's market-based rate authority is governed by tariffs that are subject to the jurisdiction of a rate regulatory agency such as the Federal Energy Regulatory Commission.

Response: The commenter's suggestions would undermine the NRC's longstanding basis for not requiring financial qualifications reviews for electric utilities, which is that the recovery of costs is assured. Accordingly, the NRC does not believe that the commentator's suggestions warrant further consideration.

Comment 24: One commenter states that if the proposed changes to 10 CFR 50.33 are finalized, then the NRC should adopt and implement procedures to formally and continually monitor the financial qualifications of non-electric utility power reactor licensees.

Response: The NRC will consider the commenter's suggestion when the NRC's internal guidance for reviewing licensees' financial information is revised.

Section-by-Section Analysis

10 CFR 50.33, Contents of Applications; General Information

Section 50.33(f)(2) is amended to state that power reactor applicants for license renewal need not provide financial qualifications information. Nonpower reactor applicants would continue to submit financial qualifications information in their applications. A new sentence is added to § 50.33(f)(2) to specify that nonpower reactor license renewal applicants must continue to submit financial qualifications information in their applications.

10 CFR 50.76, Licensee's Change of Status; Financial Qualifications

A new § 50.76 requires that a licensee changing from an electric utility to a non-electric utility entity (*i.e.*, a company that does not obtain revenue from the cost-of-service rate making process), in a manner other than a license transfer under 10 CFR 50.80, must submit the financial information required by § 50.33(f)(2) for obtaining an operating license. The section also requires that the licensee notify the NRC 75 days before the transition and provide the financial information at that time. The language of the proposed rule was changed slightly to spell out "seventy-five."

Availability of Documents

The NRC is making the documents identified below available to interested persons through one or more of the following:

Public Document Room (PDR). The NRC Public Document Room is located at 11555 Rockville Pike, Public File Area O–1 F21, Rockville, Maryland.

Rulemaking Web site. The NRC's interactive rulemaking Web site is located at *http://ruleforum.llnl.gov*. The documents may be viewed and downloaded electronically via this Web site.

The NRC's Public Electronic Reading Room (PERR). The NRC's public electronic Reading Room is located at *http://www.nrc.gov/reading-rm.html*.

The NRC staff contact (NRC Staff). Single copies of the final rule, the Regulatory Analysis, and the Environmental Assessment may be obtained from George J. Mencinsky, Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001.

Alternatively, you may contact Mr. Mencinsky at (301) 415–3093 or via e-mail to *gjm@nrc.gov*.

Document	PDR	Web	PERR	NRC Staff
Regulatory Analysis	X	X	ML032460795	X
Environmental Assessment	X	X	ML032460815	X
Public Comments Received	X		ML032670833	X

Voluntary Consensus Standards

The National Technology Transfer and Advancement Act of 1995, Pub. L. 104–113, requires that Federal agencies use technical standards that are developed or adopted by voluntary consensus standard bodies unless the use of such a standard is inconsistent with applicable law or is otherwise impractical. In this final rule, the NRC eliminates the requirement that applicants for power reactor license renewal provide financial qualifications information and adds a new requirement for submission of financial information on electric utilities holding operating licenses for nuclear power reactors if the applicants cease to be electric utilities in a manner other than a license transfer under 10 CFR 50.80. This final rule would not constitute a standard that establishes generally applicable requirements, and the requirement to use a voluntary consensus standard is not applicable.

Finding of No Significant Environmental Impact: Availability

The Commission has determined under the National Environmental Policy Act of 1969, as amended, and the Commission's regulations in subpart A of 10 CFR part 51, that this rule is not a major Federal action significantly affecting the quality of the human environment, and, therefore, an environmental impact statement is not required.

This rulemaking will not increase the probability or consequences of accidents. No changes are being made in the types of any effluents that may be released off site, and there is no increase in public radiation exposure. Therefore, there are no radiological impacts associated with the action. The rulemaking does not involve nonradiological plant effluents and has no other environmental impact. Therefore, no nonradiological impacts are associated with the action. Therefore, the NRC determines that there will be no off site impact to the public from this action.

The basis for NRC's finding is set forth in an Environmental Assessment on this final rule. The Environmental Assessment is available as indicated in the section under the Availability of Documents heading. The NRC requested the views of the States on the environmental assessment for the rule and did not receive any comments from the States.

Paperwork Reduction Act Statement

This final rule eliminates the burden on non-electric utility power reactor licensees to submit financial qualifications information upon license renewal as required by the current § 50.33(f)(2). The public burden reduction for this information collection is estimated to average 100 hours per request. Power reactor licensees that transition from electric utility to non-electric utility power reactor entities without transferring the license would be required to provide this information under a new § 50.76. Because the burden reduction for this information collection is insignificant, Office of Management and Budget (OMB) clearance is not required. Existing requirements were approved by the Office of Management and Budget, approval number 3150–0011.

Public Protection Notification

The NRC may not conduct or sponsor, and a person is not required to respond to, a request for information or an information collection requirement unless the requesting document displays a currently valid OMB control number.

Regulatory Analysis

The Commission has prepared a Regulatory Analysis on this final regulation. The analysis examines the costs and benefits of the alternatives considered by the Commission. The Regulatory Analysis may be examined, and/or copied for a fee, at the NRC's Public Document Room at One White Flint North, 11555 Rockville Pike (first floor), Rockville, Maryland. Single copies of the analysis may be obtained from George J. Mencinsky, Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, telephone (301) 415–3093, e-mail *gjm@nrc.gov*.

Regulatory Flexibility Certification

In accordance with the Regulatory Flexibility Act of 1980, (5 U.S.C. 605(b)), the Commission certifies that this final rule will not have a significant economic impact on a substantial number of small entities. This final rule affects only the licensing and operation of nuclear power plants. The companies that own these plants do not fall within the scope of the definition of "small entities" set forth in the Regulatory Flexibility Act or the size standards established by the NRC (10 CFR 2.810).

Backfit Analysis

The NRC has determined that the backfit rule does not apply to this final rule. The final rule will (1) permissively relax the current requirement in § 50.33(f) for submission of financial qualifications information by entities other than electric utilities seeking renewal of their nuclear power plant operating licenses, and (2) impose a new requirement for submission of financial information on electric utilities who hold operating licenses for nuclear power reactors and, then cease to be electric utilities in a manner other than a license transfer under 10 CFR 50.80. These information collection and reporting requirements do not constitute regulatory actions to which the backfit rule applies. In addition, with respect to the permissive relaxation in § 50.33(f), such relaxations do not "impose" a requirement, which is an essential element of "backfitting" as defined in § 50.109(a)(1).

Accordingly, the final rule's provisions do not constitute a backfit and a backfit analysis need not be performed. However, the staff has prepared a regulatory analysis that identifies the benefits and costs of the final rule and evaluates other options for addressing the identified issues. As such, the regulatory analysis constitutes a "disciplined approach" for evaluating the merits of the final rule and is consistent with the intent of the backfit rule.

Small Business Regulatory Enforcement Fairness Act

In accordance with the Small Business Regulatory Enforcement Fairness Act of 1996, the NRC has determined that this action is not a major rule and has verified this determination with the Office of

Information and Regulatory Affairs of OMB.

List of Subjects in 10 CFR Part 50

Antitrust, Classified information, Criminal penalties, Fire protection, Intergovernmental relations, Nuclear power plants and reactors, Radiation protection, Reactor siting criteria, Reporting and recordkeeping requirements.

■ For the reasons set forth in the preamble and under the authority of the Atomic Energy Act of 1954, as amended; the Energy Reorganization Act of 1974, as amended; and 5 U.S.C. 552 and 553, the NRC is adopting the following amendments to 10 CFR part 50.

PART 50—DOMESTIC LICENSING OF PRODUCTION AND UTILIZATION FACILITIES

■ 1. The authority citation for part 50 continues to read as follows:

Authority: Secs. 102, 103, 104, 105, 161, 182, 183, 186, 189, 68 Stat. 936, 937,938, 948, 953, 954, 955, 956, as amended, sec. 234, 83 Stat. 444, as amended (42 U.S.C. 2132, 2133, 2134, 2135, 2201, 2232, 2233, 2236, 2239, 2282); secs. 201, as amended, 202, 206, 88 Stat. 1242, as amended, 1244, 1246 (42 U.S.C. 5841, 5842, 5846).

Section 50.7 also issued under Pub. L. 95–601, sec. 10, 92 Stat. 2951 (42 U.S.C. 5841). Section 50.10 also issued under secs. 101, 185, 68 Stat. 955, as amended (42 U.S.C. 2131, 2235); sec. 102, Pub. L. 91–190, 83 Stat. 853 (42 U.S.C. 4332). Sections 50.13, 50.54(dd), and 50.103 also issued under sec. 108, 68 Stat. 939, as amended (42 U.S.C. 2138). Sections 50.23, 50.35, 50.55, and 50.56 also issued under sec. 185, 68 Stat. 955 (42 U.S.C. 2235). Sections 50.33a, 50.55a, and Appendix Q also issued under sec. 102, Pub. L. 91–190, 83 Stat. 853 (42 U.S.C. 4332). Sections 50.34 and 50.54 also issued under sec. 204, 88 Stat. 1245 (42 U.S.C. 5844). Sections 50.58, 50.91, and 50.92 also issued under Pub. L. 97–415, 96 Stat. 2073 (42 U.S.C. 2239). Section 50.78 also issued under sec. 122, 68 Stat. 939 (42 U.S.C. 2152). Sections 50.80 and 50.81 also issued under sec. 184, 68 Stat. 954, as amended (42 U.S.C. 2234). Appendix F also issued under sec. 187, 68 Stat. 955 (42 U.S.C. 2237).

■ 2. In § 50.33, paragraph (f)(2) is revised to read as follows:

§ 50.33. Contents of applications; general information.

* * * * *

(f) * * *

(2) If the application is for an operating license, the applicant shall submit information that demonstrates the applicant possesses or has reasonable assurance of obtaining the funds necessary to cover estimated operation costs for the period of the license. The applicant shall submit estimates for total annual operating costs for each of the first five years of operation of the facility. The applicant shall also indicate the source(s) of funds to cover these costs. An applicant seeking to renew or extend the term of an operating license for a power reactor need not submit the financial information that is required in an application for an initial license. Applicants to renew or extend the term of an operating license for a nonpower reactor shall include the financial information that is required in an application for an initial license.

* * * * *

■ 3. Section 50.76 is added to read as follows:

§ 50.76. Licensee's change of status; financial qualifications.

An electric utility licensee holding an operating license (including a renewed license) for a nuclear power reactor, no later than seventy-five (75) days prior to ceasing to be an electric utility in any manner not involving a license transfer under § 50.80, shall provide the NRC with the financial qualifications information that would be required for obtaining an initial operating license as specified in § 50.33(f)(2). The financial qualifications information must address the first full five years of operation after the date the licensee ceases to be an electric utility.

Dated at Rockville, Maryland, this 26th day of January 2004.

For the Nuclear Regulatory Commission.

Annette L. Vietti-Cook,

Secretary of the Commission.

[FR Doc. 04–1942 Filed 1–29–04; 8:45 am]

BILLING CODE 7590–01–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. 2002–NM–82–AD; Amendment 39–13444; AD 2004–02–09]

RIN 2120–AA64

Airworthiness Directives; McDonnell Douglas Model DC–9–81 (MD–81), DC–9–82 (MD–82), DC–9–83 (MD–83), DC–9–87 (MD–87), and MD–88 Airplanes

AGENCY: Federal Aviation Administration, DOT.

ACTION: Final rule.

SUMMARY: This amendment adopts a new airworthiness directive (AD), applicable to certain McDonnell Douglas Model DC–9–81 (MD–81), DC–9–82 (MD–82), DC–9–83 (MD–83), DC–9–87 (MD–87), and MD–88 airplanes. This action requires a one-time visual inspection to determine if discrepant circuit breakers are installed, and corrective action if necessary. This action is necessary to prevent internal overheating and arcing of circuit breakers and airplane wiring due to long-term use and breakdown of internal components of the circuit breakers, which could result in smoke and fire in the flight compartment and main cabin. This action is intended to address the identified unsafe condition.

DATES: Effective March 5, 2004.

The incorporation by reference of certain publications listed in the regulations is approved by the Director of the Federal Register as of March 5, 2004.

ADDRESSES: The service information referenced in this AD may be obtained from Boeing Commercial Aircraft Group, Long Beach Division, 3855 Lakewood Boulevard, Long Beach, California 90846, Attention: Data and Service Management, Dept. C1–L5A (D800–0024). This information may be examined at the Federal Aviation Administration (FAA), Transport Airplane Directorate, Rules Docket, 1601 Lind Avenue, SW., Renton, Washington; or at the FAA, Los Angeles Aircraft Certification Office, 3960 Paramount Boulevard, Lakewood, California; or at the Office of the Federal Register, 800 North Capitol Street, NW., suite 700, Washington, DC.

FOR FURTHER INFORMATION CONTACT: Elvin K. Wheeler, Aerospace Engineer, Systems and Equipment Branch, ANM–130L, FAA, Los Angeles Aircraft Certification Office, 3960 Paramount Boulevard, Lakewood, California 90712–4137; telephone (562) 627–5344; fax (562) 627–5210.

SUPPLEMENTARY INFORMATION: A proposal to amend part 39 of the Federal Aviation Regulations (14 CFR part 39) to include an airworthiness directive (AD) that is applicable to certain McDonnell Douglas Model DC–9–81 (MD–81), DC–9–82 (MD–82), DC–9–83 (MD–83), DC–9–87 (MD–87), and MD–88 airplanes was published in the **Federal Register** on May 23, 2003 (68 FR 28175). That action proposed to require a one-time visual inspection to determine if discrepant circuit breakers are installed, and corrective action if necessary.

Comments

Interested persons have been afforded an opportunity to participate in the making of this amendment. Due consideration has been given to the comments received.

Support for Proposed AD

One commenter concurs with the proposed AD.

Request To Delay Rule Until Certain Part Numbers (P/N) Are Removed From Manufacturer's Parts List

The other commenter, an operator, requests that the final rule not be released until the Wood Electric circuit breaker P/Ns are removed from Boeing's Approved Equivalent Parts List. The commenter states that Boeing should ensure that the affected parts are purged from the Boeing specification part stock, with the supporting documentation reflecting only acceptable parts. The commenter further states that the Wood Electric circuit breaker P/Ns are still approved to the Boeing specification numbers listed in the referenced alert service bulletin as the parts to be installed for the terminating action specified in the proposed AD. The commenter asserts that this will increase the possibility that the discrepant circuit breakers may still be installed on airplanes in the future.

We do not agree. We have confirmed with the manufacturer, Boeing, that it has revised the Approved Equivalent Parts List and inserted an "x" code by all Wood Electric circuit breakers. This prohibits those parts from being ordered and installed. The Wood Electric circuit breakers are no longer being manufactured and have been out of production for over twenty years, and, therefore, are no longer available from parts stock. Boeing Alert Service Bulletin MD80–24A194, Revision 01, dated March 11, 2003, referenced in this final rule, specifies that Wood Electric Corporation and Wood Electric Division of Potter Brumfield Corporation circuit breakers be replaced with currently approved circuit breakers. No change to this final rule is necessary.

Conclusion

After careful review of the available data, including the comments noted above, the FAA has determined that air safety and the public interest require the adoption of the rule as proposed.

Changes to 14 CFR Part 39/Effect on the AD

On July 10, 2002, the FAA issued a new version of 14 CFR part 39 (67 FR 47997, July 22, 2002), which governs the FAA's airworthiness directives system. The regulation now includes material that relates to altered products, special flight permits, and alternative methods of compliance. However, for clarity and consistency in this final rule, we have retained the language of the NPRM regarding that material.

Increase in Labor Rate

After the proposed rule was issued, we reviewed the figures we use to calculate the labor rate to do the required actions. To account for various inflationary costs in the airline industry, we find it appropriate to increase the labor rate used in these calculations from $60 per work hour to $65 per work hour. The economic impact information, below, has been revised to reflect this increase in the specified hourly labor rate.

Cost Impact

There are approximately 1,177 airplanes of the affected design in the worldwide fleet. The FAA estimates that 709 airplanes of U.S. registry will be affected by this AD, that it will take approximately 80 work hours per airplane to accomplish the required inspection of the circuit breakers (over 700 installed on each airplane), and that the average labor rate is $65 per work hour. Based on these figures, the cost impact of the AD on U.S. operators is estimated to be $3,686,800, or $5,200 per airplane.

The cost impact figure discussed above is based on assumptions that no operator has yet accomplished any of the requirements of this AD action, and that no operator would accomplish those actions in the future if this AD were not adopted. The cost impact figures discussed in AD rulemaking actions represent only the time necessary to perform the specific actions actually required by the AD. These figures typically do not include incidental costs, such as the time required to gain access and close up, planning time, or time necessitated by other administrative actions.

Regulatory Impact

The regulations adopted herein will not have a substantial direct effect on the States, on the relationship between the national Government and the States, or on the distribution of power and responsibilities among the various levels of government. Therefore, it is determined that this final rule does not have federalism implications under Executive Order 13132.

For the reasons discussed above, I certify that this action (1) is not a "significant regulatory action" under Executive Order 12866; (2) is not a "significant rule" under DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979); and (3) will not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act. A final evaluation has been prepared for this action and it is contained in the Rules Docket. A copy of it may be obtained from the Rules Docket at the location provided under the caption **ADDRESSES.**

List of Subjects in 14 CFR Part 39

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

Adoption of the Amendment

■ Accordingly, pursuant to the authority delegated to me by the Administrator, the Federal Aviation Administration amends part 39 of the Federal Aviation Regulations (14 CFR part 39) as follows:

PART 39—AIRWORTHINESS DIRECTIVES

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

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

§ 39.13 [Amended]

■ 2. Section 39.13 is amended by adding the following new airworthiness directive:

2004–02–09 McDonnell Douglas: Amendment 39–13444. Docket 2002–NM–82–AD.

Applicability: Model DC–9–81 (MD–81), DC–9–82 (MD–82), DC–9–83 (MD–83), DC–9–87 (MD–87), and MD–88 airplanes; as listed in Boeing Alert Service Bulletin MD80–24A194, Revision 01, dated March 11, 2003; certificated in any category.

Note 1: This AD applies to each airplane identified in the preceding applicability provision, regardless of whether it has been modified, altered, or repaired in the area subject to the requirements of this AD. For airplanes that have been modified, altered, or repaired so that the performance of the requirements of this AD is affected, the owner/operator must request approval for an alternative method of compliance in accordance with paragraph (c) of this AD. The request should include an assessment of the effect of the modification, alteration, or repair on the unsafe condition addressed by this AD; and, if the unsafe condition has not been eliminated, the request should include specific proposed actions to address it.

Compliance: Required as indicated, unless accomplished previously.

To prevent internal overheating and arcing of circuit breakers and airplane wiring due to long-term use and breakdown of internal components of the circuit breakers, which could result in smoke and fire in the flight compartment and main cabin, accomplish the following:

Inspection and Replacement, if Necessary

(a) Within 18 months after the effective date of this AD: Perform a one-time general visual inspection of the circuit breakers to determine if discrepant circuit breakers are installed (includes circuit breakers manufactured by Wood Electric and Wood Electric Division of Brumfield Potter Corporations, and incorrect circuit breakers installed per Boeing Alert Service Bulletin MD80–24A194, dated February 19, 2002), per Boeing Alert Service Bulletin MD80–24A194, Revision 01, dated March 11, 2003.

Note 2: For the purposes of this AD, a general visual inspection is defined as: "A visual examination of an interior or exterior area, installation, or assembly to detect obvious damage, failure, or irregularity. This level of inspection is made from within touching distance unless otherwise specified. A mirror may be necessary to enhance visual access to all exposed surfaces in the inspection area. This level of inspection is made under normally available lighting conditions such as daylight, hangar lighting, flashlight, or droplight and may require removal or opening of access panels or doors. Stands, ladders, or platforms may be required to gain proximity to the area being checked."

(1) If no discrepant circuit breaker is found: No further action is required by this paragraph.

(2) If any discrepant circuit breaker is found: Before further flight, replace the circuit breaker with a new, approved circuit breaker, per the service bulletin.

Part Installation

(b) As of the effective date of this AD, no person shall install, on any airplane, a circuit breaker having a part number listed in the "Existing Part Number" column in the table specified in paragraph 2.C.2. of Boeing Alert Service Bulletin MD80–24A194, Revision 01, dated March 11, 2003.

Alternative Methods of Compliance

(c) An alternative method of compliance or adjustment of the compliance time that provides an acceptable level of safety may be used if approved by the Manager, Los Angeles Aircraft Certification Office (ACO), FAA. Operators shall submit their requests through an appropriate FAA Principal Maintenance Inspector, who may add comments and then send it to the Manager, Los Angeles ACO.

Note 3: Information concerning the existence of approved alternative methods of compliance with this AD, if any, may be obtained from the Los Angeles ACO.

Special Flight Permit

(d) Special flight permits may be issued in accordance with sections 21.197 and 21.199 of the Federal Aviation Regulations (14 CFR 21.197 and 21.199) to operate the airplane to a location where the requirements of this AD can be accomplished.

Incorporation by Reference

(e) The actions shall be done in accordance with Boeing Alert Service Bulletin MD80–24A194, Revision 01, dated March 11, 2003. This incorporation by reference was approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. Copies may be obtained from Boeing Commercial Aircraft Group, Long Beach Division, 3855 Lakewood Boulevard, Long Beach, California 90846, Attention: Data and Service Management, Dept. C1–L5A (D800–0024). Copies may be inspected at the FAA, Transport Airplane Directorate, 1601 Lind Avenue, SW., Renton, Washington; or at the FAA, Los Angeles Aircraft Certification Office, 3960 Paramount Boulevard, Lakewood, California; or at the Office of the Federal Register, 800 North Capitol Street, NW., suite 700, Washington, DC.

Effective Date

(f) This amendment becomes effective on March 5, 2004.

Issued in Renton, Washington, on January 20, 2004.

Kalene C. Yanamura,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 04–1913 Filed 1–29–04; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. 2003–NM–43–AD; Amendment 39–13441; AD 2004–02–06]

RIN 2120–AA64

Airworthiness Directives; McDonnell Douglas Model DC–10–10, DC–10–10F, DC–10–15, DC–10–30, DC–10–30F, DC–10–30F (KC–10A– and KDC–10), DC–10–40, DC–10–40F, MD–10–10F, and MD–10–30F Airplanes; and Model MD–11 and MD–11F Airplanes

AGENCY: Federal Aviation Administration, DOT.

ACTION: Final rule.

SUMMARY: This amendment adopts a new airworthiness directive (AD), applicable to certain McDonnell Douglas transport category airplanes. For certain airplanes, this amendment requires a general visual inspection to detect cracking in the nuts on the lower attach bolt assemblies of the forward attach bracket of the inboard flap outboard hinge, replacement of both upper and lower attach bolt assemblies with new bolts and nuts made from Inconel material, and replacement of certain preload-indicating (PLI) washers with new washers. For certain other airplanes, this amendment requires replacement of the lower attach bolt assemblies of the inboard forward attach bracket of the inboard flap outboard hinge with new bolts and nuts made from Inconel material, and replacement of PLI washers with new washers. This action is necessary to prevent separation of the inboard flap outboard hinge from the wing structure and consequent reduced controllability of the airplane. This action is intended to address the identified unsafe condition.

DATES: Effective March 5, 2004.

The incorporation by reference of certain publications listed in the regulations is approved by the Director of the Federal Register as of March 5, 2004.

ADDRESSES: The service information referenced in this AD may be obtained from Boeing Commercial Airplanes, Long Beach Division, 3855 Lakewood Boulevard, Long Beach, California 90846, Attention: Data and Service Management, Dept. C1–L5A (D800–0024). This information may be examined at the Federal Aviation Administration (FAA), Transport Airplane Directorate, Rules Docket, 1601 Lind Avenue, SW., Renton, Washington; or at the FAA, Los Angeles Aircraft Certification Office, 3960 Paramount Boulevard, Lakewood, California; or at the Office of the Federal Register, 800 North Capitol Street, NW., suite 700, Washington, DC.

FOR FURTHER INFORMATION CONTACT: Ronald Atmur, Aerospace Engineer, Airframe Branch, ANM–120L, FAA, Los Angeles Aircraft Certification Office, 3960 Paramount Boulevard, Lakewood, California 90712–4137; telephone (562) 627–5224; fax (562) 627–5210.

SUPPLEMENTARY INFORMATION: A proposal to amend part 39 of the Federal Aviation Regulations (14 CFR part 39) to include an airworthiness directive (AD) that is applicable to certain McDonnell Douglas transport category airplanes was published in the **Federal Register** on September 30, 2003 (68 FR 56216). That action proposed to require, for certain airplanes, a general visual inspection to detect cracking in the nuts on the lower attach bolt assemblies of the forward attach bracket of the inboard flap outboard hinge, replacement of both upper and lower attach bolt assemblies with new bolts and nuts made from Inconel material, and replacement of certain preload-indicating (PLI) washers with new washers. For certain other airplanes, that action proposed to require replacement of the lower attach bolt assemblies of the inboard forward attach bracket of the inboard flap outboard hinge with new bolts and nuts made from Inconel material, and replacement of PLI washers with new washers.

Comments

Interested persons have been afforded an opportunity to participate in the making of this amendment. No comments were submitted in response to the proposal or the FAA's determination of the cost to the public.

Conclusion

The FAA has determined that air safety and the public interest require the adoption of the rule as proposed.

Cost Impact

There are approximately 394 Model DC–10 and Model MD–10 airplanes, and approximately 192 Model MD–11 and –11F airplanes of the affected design in the worldwide fleet. The FAA estimates that 252 DC–10 and Model MD–10 airplanes, and 76 Model MD–11 and –11F airplanes of U.S. registry will be affected by this AD, and that the average labor rate is $65 per hour.

The following table shows the estimated cost impact for airplanes affected by this AD:

TABLE—COST IMPACT ESTIMATE

Model	Work hours	Labor cost per airplane	Parts cost per airplane	Fleet cost
DC–10 and MD–10 airplanes	25	$1,625	$4,139	$1,452,528
MD–11 and –11F airplanes	13	845	2,041	219,336

The cost impact figures discussed above are based on assumptions that no operator has yet accomplished any of the requirements of this AD action, and that no operator would accomplish those actions in the future if this AD were not adopted. The cost impact figures discussed in AD rulemaking actions represent only the time necessary to perform the specific actions actually required by the AD. These figures typically do not include incidental costs, such as the time required to gain access and close up, planning time, or time necessitated by other administrative actions.

Regulatory Impact

The regulations adopted herein will not have a substantial direct effect on the States, on the relationship between the national Government and the States, or on the distribution of power and responsibilities among the various levels of government. Therefore, it is determined that this final rule does not have federalism implications under Executive Order 13132.

For the reasons discussed above, I certify that this action (1) is not a "significant regulatory action" under Executive Order 12866; (2) is not a "significant rule" under DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979); and (3) will not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act. A final evaluation has been prepared for this action and it is contained in the Rules Docket. A copy of it may be obtained from the Rules Docket at the location provided under the caption **ADDRESSES.**

List of Subjects in 14 CFR Part 39

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

Adoption of the Amendment

■ Accordingly, pursuant to the authority delegated to me by the Administrator, the Federal Aviation Administration amends part 39 of the Federal Aviation Regulations (14 CFR part 39) as follows:

PART 39—AIRWORTHINESS DIRECTIVES

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

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

§ 39.13 [Amended]

■ 2. Section 39.13 is amended by adding the following new airworthiness directive:

2004–02–06 McDonnell Douglas: Amendment 39–13441. Docket 2003–NM–43–AD.

Applicability: Model DC–10–10, DC–10–10F, DC–10–15, DC–10–30, DC–10–30F, DC–10–30F (KC–10A– and KDC–10), DC–10–40, DC–10–40F, MD–10–10F, and MD–10–30F airplanes, as listed in Boeing Alert Service Bulletin DC10–57A149, dated January 7, 2003; and Model MD–11 and MD–11F airplanes, as listed in Boeing Alert Service Bulletin MD11–57A068, dated January 7, 2003; certificated in any category.

Compliance: Required as indicated, unless accomplished previously.

To prevent separation of the inboard flap outboard hinge from the wing structure and consequent reduced controllability of the airplane, accomplish the following:

Replacements Accomplished per Previous Service Bulletins

(a) Replacements of steel bolts and nuts with Inconel bolts and nuts accomplished before the effective date of this AD per Boeing Service Bulletin DC10–57–116, Revision 01, dated November 25, 1996; Boeing Service Bulletin DC10–57–116, Revision 02, dated December 22, 1998; Boeing Service Bulletin DC10–57–116, Revision 03, dated May 12, 1999; and per Condition 1, Group 1 or 2, Option 1, of Boeing Alert Service Bulletin MD11–57A067, including Appendices A and B, dated July 10, 2002; are considered acceptable for compliance with the corresponding action specified in this AD.

General Visual Inspection, Model DC–10 and MD–10 Airplanes

(b) Within six months after the effective date of this AD, for all affected Model DC–10 and MD–10 airplanes, remove the encapsulating sealant from the nut side only of both assemblies and do a general visual inspection of the inboard flap, outboard hinge, forward attach bracket, lower attach bolt assembly nuts to detect cracking in the nuts, in accordance with the Accomplishment Instructions in Boeing Alert Service Bulletin DC10–57A149, dated January 7, 2003.

Note 1: For the purposes of this AD, a general visual inspection is defined as: "A visual examination of an interior or exterior area, installation, or assembly to detect obvious damage, failure, or irregularity. This level of inspection is made from within touching distance unless otherwise specified. A mirror may be necessary to enhance visual access to all exposed surfaces in the inspection area. This level of inspection is made under normally available lighting conditions such as daylight, hangar lighting, flashlight, or droplight and may require removal or opening of access panels or doors. Stands, ladders, or platforms may be required to gain proximity to the area being checked."

Replacement, Model DC–10 and MD–10 Airplanes

(c) Following the general visual inspection described in paragraph (b) of this AD, for all affected Model DC–10 and MD–10 airplanes, accomplish the applicable action(s) described in Table 1 of this AD at the specified times, per the Accomplishment Instructions in Boeing Alert Service Bulletin DC10–57A149, dated January 7, 2003. Although the Accomplishment Instructions specify to submit certain information and discrepant parts to the manufacturer, this AD does not include such a requirement.

TABLE 1.—INSPECTION AND REPLACEMENT, MODEL DC–10 AND MD–10 AIRPLANES

Condition	Actions to accomplish
(1) Cracks in either nut	(i) Option 1 (Preferred): Prior to further flight, replace both upper and lower attach bolt assemblies with new bolts and nuts made from Inconel material. (ii) Option 2: Prior to further flight, replace both lower attach bolt assemblies with new bolts and nuts made from Inconel material, and replace the preload-indicating (PLI) washers with new washers. Within 24 months after the effective date of this AD, replace both upper attach bolt assemblies with new bolts and nuts made from Inconel material, and replace the preload-indicating (PLI) washers with new washers.
(2) No cracks in nuts	Within 24 months after the effective date of this AD, replace both upper and lower attach bolt assemblies with bolts and nuts made from Inconel material, and replace the PLI washers with new washers, as applicable.

Replacement, Model MD–11 and –11F Airplanes

(d) Replace the inboard flap, outboard hinge, forward attach bracket, lower attach bolt assemblies of the affect Model MD–11 and MD–11F airplanes with new bolts and nuts made from Inconel material and replace the PLI washers with new PLI washers within the compliance time for the applicable condition described in Table 2 of this AD. Accomplish all replacements per the Accomplishment Instructions in Boeing Alert Service Bulletin MD11–57A068, dated January 7, 2003.

TABLE 2.—CONDITION AND COMPLIANCE TIME, MODEL MD–11 AND –11F AIRPLANES

Condition	Compliance time
MD–11 and MD–11F airplanes that have not replaced steel bolts and nuts with new like parts or Inconel bolts per group 1 or 2, option 1 or 2 of Boeing Alert Service Bulletin MD11–57A067, including Appendices A and B, dated July 10, 2002.	Within 18 months after the effective date of this AD.
MD–11 and MD–11F airplanes that have replaced steel bolts and nuts with new steel bolts and steel nuts per group 1 or 2, option 2, table 2, note 7 of Boeing Alert Service Bulletin MD11–57A067, including Appendices A and B, dated July 10, 2002.	Within 36 months after the effective date of this AD.
MD–11 and MD–11F airplanes that have replaced steel bolts and nuts with new steel bolts and new Inconel nuts per Group 1 or 2, Option 2 of Boeing Alert Service Bulletin MD11–57A067, including Appendices A and B, dated July 10, 2002.	Within 60 months after the effective date of this AD.

Alternative Methods of Compliance

(e) In accordance with 14 CFR 39.19, the Manager, Los Angeles Aircraft Certification Office (ACO), FAA, is authorized to approve alternative methods of compliance (AMOCs) for this AD.

Incorporation by Reference

(f) The actions shall be done in accordance with Boeing Alert Service Bulletin DC10–57A149, dated January 7, 2003; or Boeing Alert Service Bulletin MD11–57A068, dated January 7, 2003; as applicable. This incorporation by reference was approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. Copies may be obtained from Boeing Commercial Airplanes, Long Beach Division, 3855 Lakewood Boulevard, Long Beach, California 90846, Attention: Data and Service Management, Dept. C1–L5A (D800–0024). Copies may be inspected at the FAA, Transport Airplane Directorate, 1601 Lind Avenue, SW., Renton, Washington; or at the FAA, Los Angeles Aircraft Certification Office, 3960 Paramount Boulevard, Lakewood, California; or at the Office of the Federal Register, 800 North Capitol Street, NW., suite 700, Washington, DC.

Effective Date

(g) This amendment becomes effective on March 5, 2004.

Issued in Renton, Washington, on January 20, 2004.

Kalene C. Yanamura,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 04–1909 Filed 1–29–04; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. 2001–NM–88–AD; Amendment 39–13443; AD 2004–02–08]

RIN 2120–AA64

Airworthiness Directives; Boeing Model 737–300, –400, and –500 Series Airplanes

AGENCY: Federal Aviation Administration, DOT.

ACTION: Final rule.

SUMMARY: This amendment adopts a new airworthiness directive (AD), applicable to certain Boeing Model 737–300, –400, and –500 series airplanes. This amendment requires, for certain airplanes, replacement of the hinge assemblies on certain escape slide compartments of the forward doors with new, stronger hinge assemblies; and, for certain other airplanes, an inspection for incorrectly crimped hinge assemblies, and corrective action if necessary. The actions specified by this AD are intended to prevent forward door escape slides from falling out of their compartments into the airplane interior and inflating, which could impede an evacuation in the event of an emergency. This action is intended to address the identified unsafe condition.

DATES: Effective March 5, 2004.

The incorporation by reference of a certain publication listed in the regulations is approved by the Director of the Federal Register as of March 5, 2004.

ADDRESSES: The service information referenced in this AD may be obtained from Boeing Commercial Airplanes, P.O. Box 3707, Seattle, Washington 98124–2207. This information may be examined at the Federal Aviation Administration (FAA), Transport Airplane Directorate, Rules Docket, 1601 Lind Avenue, SW., Renton, Washington; or at the Office of the Federal Register, 800 North Capitol Street, NW., suite 700, Washington, DC.

FOR FURTHER INFORMATION CONTACT: Keith Ladderud, Aerospace Engineer, Cabin Safety and Environmental Systems Branch, ANM–150S, FAA, Seattle Aircraft Certification Office, 1601 Lind Avenue, SW., Renton, Washington 98055–4056; telephone (425) 917–6435; fax (425) 917–6590.

SUPPLEMENTARY INFORMATION: A proposal to amend part 39 of the Federal Aviation Regulations (14 CFR part 39) to include an airworthiness directive (AD) that is applicable to certain Boeing Model 737–300, –400, and –500 series airplanes was published as a supplemental notice of proposed rulemaking (NPRM) in the **Federal Register** on September 19, 2003 (68 FR 54869). That action proposed to require, for certain airplanes, replacement of the hinge assemblies on certain escape slide compartments of the forward doors with new, stronger hinge assemblies; and, for certain other airplanes, an inspection for incorrectly crimped hinge assemblies, and corrective action if necessary.

Comments

Interested persons have been afforded an opportunity to participate in the making of this amendment. Due consideration has been given to the comments received.

Agrees With the Proposed AD

One commenter generally agrees with the proposed AD and has no additional comments.

Allow for Reinstallation of the Hinges During Maintenance

One commenter requests that the proposed AD be revised to allow reinstallation of the existing hinge assemblies if a maintenance action not associated with the proposed AD requires the removal of the escape slide/hinge assemblies. This would allow normal operations until the replacement of the hinge assemblies is completed per planned maintenance. The commenter believes paragraph (c) of the proposed AD prohibits normal maintenance actions that require the removal and reinstallation of the escape slide/hinge assemblies. The commenter believes their proposal would allow for normal maintenance without disruption while replacing the hinge assemblies within the compliance time of the proposed AD and without any degradation of safety.

We agree with the commenter that clarification is necessary. The intent of paragraph (c) of the proposed AD is that when operators replace parts, they should replace them with good parts rather than bad parts. Doing normal maintenance where the escape slide assembly is removed does not warrant immediate replacement of the hinge assembly. By reinstalling the escape slide assembly, the operator is not "replacing" the hinge assembly. The hinge assembly replacement would be done within the compliance time of the AD. The final rule has been clarified accordingly.

Conclusion

After careful review of the available data, including the comments noted above, the FAA has determined that air safety and the public interest require the adoption of the rule with the changes previously described.

Cost Impact

There are approximately 1,974 airplanes of the affected design in the worldwide fleet. The FAA estimates that 793 airplanes of U.S. registry will be affected by this AD.

Replacement of the hinge assemblies, if necessary, will take approximately 5 work hours per airplane, at an average labor rate of $65 per work hour. Required parts will cost approximately $1,569 per airplane. Based on these figures, the cost impact of the hinge replacement is estimated to be $1,894 per airplane.

The inspection, if necessary, will take approximately 1 to 3 work hours per airplane, at an average labor rate of $65 per work hour. Based on these figures, the cost impact of the inspection is estimated to be $65 to $195 per airplane.

The cost impact figures discussed above are based on assumptions that no operator has yet accomplished any of the requirements of this AD action, and that no operator would accomplish those actions in the future if this AD were not adopted. The cost impact figures discussed in AD rulemaking actions represent only the time necessary to perform the specific actions actually required by the AD. These figures typically do not include incidental costs, such as the time required to gain access and close up, planning time, or time necessitated by other administrative actions.

Regulatory Impact

The regulations adopted herein will not have a substantial direct effect on the States, on the relationship between the national Government and the States, or on the distribution of power and responsibilities among the various levels of government. Therefore, it is determined that this final rule does not have federalism implications under Executive Order 13132.

For the reasons discussed above, I certify that this action (1) is not a "significant regulatory action" under Executive Order 12866; (2) is not a "significant rule" under DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979); and (3) will not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act. A final evaluation has been prepared for this action and it is contained in the Rules Docket. A copy of it may be obtained from the Rules Docket at the location provided under the caption **ADDRESSES**.

List of Subjects in 14 CFR Part 39

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

Adoption of the Amendment

■ Accordingly, pursuant to the authority delegated to me by the Administrator, the Federal Aviation Administration amends part 39 of the Federal Aviation Regulations (14 CFR part 39) as follows:

PART 39—AIRWORTHINESS DIRECTIVES

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

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

§ 39.13 [Amended]

■ 2. Section 39.13 is amended by adding the following new airworthiness directive:

2004–02–08 Boeing: Amendment 39–13443. Docket 2001–NM–88–AD.

Applicability: Model 737–300, –400, and –500 series airplanes; certificated in any category; as listed in Boeing Special Attention Service Bulletin 737–25–1430, Revision 1, dated April 10, 2003.

Compliance: Required as indicated, unless accomplished previously.

To prevent forward door escape slides from falling out of their compartments into the airplane interior and inflating, which could impede an evacuation in the event of emergency, accomplish the following:

Hinge Assembly Replacement

(a) For airplanes on which the hinge assemblies have not been replaced as of the effective date of this AD in accordance with Boeing Special Attention Service Bulletin 737–25–1430, dated February 22, 2001: Within 36 months after the effective date of this AD, replace the hinge assemblies on the escape slide stowage compartments of the forward doors with new, stronger hinge assemblies, in accordance with Part 1 of the Accomplishment Instructions of Boeing Special Attention Service Bulletin 737–25–1430, Revision 1, dated April 10, 2003.

Hinge Assembly Inspection

(b) For airplanes on which the hinge assemblies were replaced before the effective date of this AD in accordance with Boeing

Special Attention Service Bulletin 737–25–1430, dated February 22, 2001: Within 36 months after the effective date of this AD, perform a general visual inspection for incorrectly crimped hinge assemblies, in accordance with Part 2 of the Accomplishment Instructions of Boeing Special Attention Service Bulletin 737–25–1430, Revision 1, dated April 10, 2003. If any hinge assembly is not correctly crimped, perform corrective action before further flight in accordance with Revision 1 of the service bulletin.

Note 1: For the purposes of this AD, a general visual inspection is defined as: "A visual examination of an interior or exterior area, installation, or assembly to detect obvious damage, failure, or irregularity. This level of inspection is made from within touching distance unless otherwise specified. A mirror may be necessary to enhance visual access to all exposed surfaces in the inspection area. This level of inspection is made under normally available lighting conditions such as daylight, hangar lighting, flashlight, or droplight and may require removal or opening of access panels or doors. Stands, ladders, or platforms may be required to gain proximity to the area being checked."

Part Installation

(c) As of the effective date of this AD, when replacing a hinge assembly, no person may install a hinge assembly, part number 65C30431–6 or 65C30431–7, on any airplane.

Alternative Methods of Compliance

(d) In accordance with 14 CFR 39.19, the Manager, Seattle Aircraft Certification Office, FAA, is authorized to approve alternative methods of compliance for this AD.

Incorporation by Reference

(e) The actions shall be done in accordance with Boeing Special Attention Service Bulletin 737–25–1430, Revision 1, dated April 10, 2003. This incorporation by reference was approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. Copies may be obtained from Boeing Commercial Airplanes, P.O. Box 3707, Seattle, Washington 98124–2207. Copies may be inspected at the FAA, Transport Airplane Directorate, 1601 Lind Avenue, SW., Renton, Washington; or at the Office of the Federal Register, 800 North Capitol Street, NW., suite 700, Washington, DC.

Effective Date

(f) This amendment becomes effective on March 5, 2004.

Issued in Renton, Washington, on January 20, 2004.

Kalene C. Yanamura,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 04–1914 Filed 1–29–04; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. 2002–NM–311–AD; Amendment 39–13440; AD 2004–02–05]

RIN 2120–AA64

Airworthiness Directives; Bombardier Model DHC–8–400, –401, and –402 Airplanes

AGENCY: Federal Aviation Administration, DOT.

ACTION: Final rule.

SUMMARY: This amendment adopts a new airworthiness directive (AD); applicable to certain Bombardier Model DHC–8–400, –401, and –402 airplanes; that requires replacing certain flight guidance modules with improved modules, and certain flight control electronic control units with improved units. This action is necessary to prevent loss of the autopilot or manual pitch trim, which may increase the workload of the flightcrew and, under certain conditions, could result in reduced controllability of the airplane. This action is intended to address the identified unsafe condition.

DATES: Effective March 5, 2004.

The incorporation by reference of certain publications listed in the regulations is approved by the Director of the Federal Register as of March 5, 2004.

ADDRESSES: The service information referenced in this AD may be obtained from Bombardier, Inc., Bombardier Regional Aircraft Division, 123 Garratt Boulevard, Downsview, Ontario M3K 1Y5, Canada. This information may be examined at the Federal Aviation Administration (FAA), Transport Airplane Directorate, Rules Docket, 1601 Lind Avenue, SW., Renton, Washington; at the FAA, New York Aircraft Certification Office, 1600 Stewart Avenue, Westbury, New York; or at the Office of the Federal Register, 800 North Capitol Street, NW., suite 700, Washington, DC.

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

SUPPLEMENTARY INFORMATION: A proposal to amend part 39 of the Federal Aviation Regulations (14 CFR part 39) to include an airworthiness directive (AD) that is applicable to certain Bombardier Model DHC–8–400, –401, and –402 airplanes, was published in the **Federal Register** on November 18, 2003 (68 FR 65003). That action proposed to require replacing certain flight guidance modules (FGMs) with improved modules, and certain flight control electronic control units (FCECUs) with improved units.

Comments

Interested persons have been afforded an opportunity to participate in the making of this amendment. No comments were submitted in response to the proposal or the FAA's determination of the cost to the public.

Conclusion

The FAA has determined that air safety and the public interest require the adoption of the rule as proposed.

Cost Impact

We estimate that 12 airplanes of U.S. registry will be affected by the required replacement of FGMs, that it will take approximately 1 work hour per airplane to accomplish this replacement, and that the average labor rate is $65 per work hour. Required parts will be provided at no charge. Based on these figures, the cost impact of this requirement on U.S. operators is estimated to be $780, or $65 per airplane.

We estimate that 15 airplanes of U.S. registry will be affected by the required replacement of the FCECUs, that it will take approximately 4 work hours per airplane to accomplish this required replacement, and that the average labor rate is $65 per work hour. Required parts will be provided at no charge. Based on these figures, the cost impact of this requirement on U.S. operators is estimated to be $3,900, or $260 per airplane.

The cost impact figures discussed above are based on assumptions that no operator has yet accomplished any of the requirements of this AD action, and that no operator would accomplish those actions in the future if this AD were not adopted. The cost impact figures discussed in AD rulemaking actions represent only the time necessary to perform the specific actions actually required by the AD. These figures typically do not include incidental costs, such as the time required to gain access and close up, planning time, or time necessitated by other administrative actions. The manufacturer may cover the cost of replacement parts associated with this AD, subject to warranty conditions. As a result, the costs attributable to the AD may be less than stated above.

Regulatory Impact

The regulations adopted herein will not have a substantial direct effect on the States, on the relationship between the national Government and the States, or on the distribution of power and responsibilities among the various levels of government. Therefore, it is determined that this final rule does not have federalism implications under Executive Order 13132.

For the reasons discussed above, I certify that this action (1) is not a "significant regulatory action" under Executive Order 12866; (2) is not a "significant rule" under DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979); and (3) will not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act. A final evaluation has been prepared for this action and it is contained in the Rules Docket. A copy of it may be obtained from the Rules Docket at the location provided under the caption **ADDRESSES.**

List of Subjects in 14 CFR Part 39

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

Adoption of the Amendment

■ Accordingly, pursuant to the authority delegated to me by the Administrator, the Federal Aviation Administration amends part 39 of the Federal Aviation Regulations (14 CFR part 39) as follows:

PART 39—AIRWORTHINESS DIRECTIVES

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

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

§ 39.13 [Amended]

■ 2. Section 39.13 is amended by adding the following new airworthiness directive:

2004–02–05 Bombardier, Inc. (Formerly de Havilland, Inc.): Amendment 39–13440. Docket 2002–NM–311–AD.

Applicability: Model DHC–8–400, –401, and –402 airplanes; certificated in any category; having serial numbers (S/Ns) 4001 through 4065 inclusive.

Compliance: Required as indicated, unless accomplished previously.

To prevent loss of the autopilot or manual pitch trim, which may increase the workload of the flightcrew and, under certain conditions, could result in reduced controllability of the airplane, accomplish the following:

Replacement of Flight Guidance Modules

(a) For airplanes with S/Ns 4001 through 4003 inclusive and 4005 through 4058 inclusive: Within 60 days after the effective date of this AD, replace flight guidance modules (FGMs) FGM1 and FGM2, part number (P/N) C12429AA06, with improved FGMs, P/N C12429AA07, and perform a Return-to-Service procedure, per Bombardier Service Bulletin 84–22–04, Revision 'B,' dated April 17, 2002.

Note 1: Bombardier Service Bulletin 84–22–04, Revision 'B,' refers to Thales Service Bulletin C12429A–22–003, dated November 29, 2001, as an additional source of service information for modifying FGMs from P/N C12429AA06 to P/N C12429AA07. The Thales service bulletin is included in the Bombardier service bulletin.

Replacement of Flight Control Electronic Control Units

(b) For all airplanes: Within 8 months after the effective date of this AD, replace flight control electronic control units (FCECUs), P/N 398500–1001 or –1003, with improved FCECUs, P/N 398500–1005, and perform a Return-to-Service procedure, per Bombardier Service Bulletin 84–27–14, Revision 'A,' dated April 2, 2002.

Note 2: Bombardier Service Bulletin 84–27–14, Revision 'A,' refers to Parker Service Bulletin 398500–27–235, dated January 9, 2002, as an additional source of service information for modifying FCECUs from P/N 398500–1001 or –1003 to P/N 398500–1005. The Parker service bulletin is included in the Bombardier service bulletin.

Alternative Methods of Compliance

(c) In accordance with 14 CFR 39.19, the Manager, New York Aircraft Certification Office (ACO), FAA, is authorized to approve alternative methods of compliance for this AD.

Incorporation by Reference

(d) The actions shall be done in accordance with Bombardier Service Bulletin 84–22–04, Revision 'B,' dated April 17, 2002; and Bombardier Service Bulletin 84–27–14, Revision 'A,' dated April 2, 2002; as applicable. This incorporation by reference was approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. Copies may be obtained from Bombardier, Inc., Bombardier Regional Aircraft Division, 123 Garratt Boulevard, Downsview, Ontario M3K 1Y5, Canada. Copies may be inspected at the FAA, Transport Airplane Directorate, 1601 Lind Avenue, SW., Renton, Washington; at the FAA, New York Aircraft Certification Office, 1600 Stewart Avenue, Westbury, New York; or at the Office of the Federal Register, 800 North Capitol Street, NW., suite 700, Washington, DC.

Note 3: The subject of this AD is addressed in Canadian airworthiness directive CF–2002–25, dated April 25, 2002.

Effective Date

(e) This amendment becomes effective on March 5, 2004.

Issued in Renton, Washington, on January 20, 2004.

Kalene C. Yanamura,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 04–1910 Filed 1–29–04; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Office of the Secretary

49 CFR Part 5

[Docket No. OST–2004–16970]

RIN 2105–AC11

Use of Direct Final Rulemaking

AGENCY: Office of the Secretary, DOT.

ACTION: Final rule.

SUMMARY: The Office of the Secretary of Transportation (OST) is implementing a rulemaking procedure that will expedite the processing of noncontroversial changes to its regulations. OST will publish rules that the Secretary judges to be noncontroversial and unlikely to result in adverse public comment as "direct final" rules. Such direct final rules will advise the public that no adverse comment is anticipated. and that, unless written adverse comment or written notice of intent to submit adverse comment is received, the rule will become effective a specified number of days after the date it is published in the **Federal Register**. This new procedure should expedite the promulgation of routine or otherwise noncontroversial rules by reducing the time necessary to develop, review, clear, and publish separate proposed and final rules where OST receives no public comment. This rule also corrects the applicability section to remove reference to modal administrations that now have their own rulemaking procedures. These changes are made on the initiative of OST.

EFFECTIVE DATE: March 1, 2004.

FOR FURTHER INFORMATION CONTACT: Neil Eisner, Assistant General Counsel for Regulation and Enforcement, Office of the General Counsel, U.S. Department of Transportation, 400 7th Street, SW., Room 10424, Washington, DC 20590. (202) 366–4723.

SUPPLEMENTARY INFORMATION:

Background

In an August 4, 1995, Notice of Proposed Rulemaking (NPRM), 60 FR 39919, OST proposed adopting direct final rulemaking procedures for the promulgation of specified categories of rules it expects to be noncontroversial and unlikely to result in adverse comments. Direct final rulemaking, in specified cases, eliminates the unnecessary second round of internal review and clearance, as well as public review, that presently exists for all proposed rules. The National Performance Review, a presidential initiative to reorganize and streamline the federal government, and the Administrative Conference of the United States both recommended the use of "direct final" rulemaking to improve the efficiency of agency rulemaking procedures.

OST will determine when it is appropriate to employ direct final rulemaking procedures. OST will base its determination that a particular rulemaking is noncontroversial and unlikely to result in adverse comment upon its experience with similar rules that were proposed in the past and did not receive adverse public comment. OST will determine whether a comment is "adverse." An "adverse" comment is one that is critical of the rule, that suggests that the rule should not be adopted, or that suggests a change should be made in the rule. A comment submitted in support of the rule will not be considered adverse. In addition, a comment suggesting that the policy or requirements of the rule should or should not also be extended to other Departmental programs outside the scope of the rule will not be considered adverse.

Rules for which OST believes that the direct final rulemaking procedure may be appropriate include noncontroversial rules that (1) affect internal procedures of OST, such as filing requirements and rules governing the inspection and copying of documents; (2) are nonsubstantive clarifications or corrections to existing rules; (3) update existing forms; (4) make minor changes in the substantive rules regarding statistics and reporting requirements, such as a lessening of the reporting frequency (for example, from monthly to quarterly) or eliminating a type of data that no longer needs to be collected by OST; (5) make changes to the rules implementing the Privacy Act; and (6) adopt technical standards set by outside organizations, such as those developed by the Architectural Barriers and Compliance Board for determining compliance with the Americans with Disabilities Act.

OST will publish direct final rules in the final rule section of the **Federal Register**. The document will advise the public that no adverse comment is anticipated and that, unless written adverse comment or written notice of intent to submit adverse comment is received within the specified comment period, the rule will become effective a specified number of days after the date it is published. If no written adverse comment or written notice of intent to submit adverse comment is received in response to the rule, OST will then publish a notice in the **Federal Register** indicating that no adverse comment was received and confirming that the rule will become effective a specified number of days after the date that the direct final rule was published.

If, however, OST receives any written adverse comment or written notice of intent to submit adverse comment, then a notice withdrawing the direct final rule will be published in the final rule section of the **Federal Register** and, if the agency decides a rulemaking is still warranted, a notice of proposed rulemaking will be published in the proposed rule section. The proposed rule will provide for a new comment period. The additional time and effort necessary to withdraw the rule and issue a Notice of Proposed Rulemaking if there is adverse comment will serve as incentive for OST to act conservatively in evaluating whether to use the procedure for a particular rule.

Response to Comments

OST received five comments on the NPRM. They were submitted by the Advocates For Highway and Auto Safety (Advocates), the Air Transport Association of America (ATA), Enron Operations Corp. (EOC), Akzo Nobel Chemicals, and Panhandle Eastern Corporation (Panhandle). Although commenters expressed general support for the direct final rule procedure, they expressed concern over certain aspects of the process. OST has decided to adopt the direct final rule procedures proposed in the NPRM with some minor modifications to address the concerns raised in the comments.

ATA argued that publishing the direct final rule in the proposed rule section of the **Federal Register** would be more appropriate than publishing it in the final rule section. ATA believes that people may misunderstand that the direct final rule is a proposal on which they may comment if it is published in the final rule section of the **Federal Register**. OST is required to publish final rules in the final rule section of the **Federal Register** in order to codify them in the Code of Federal Regulations. The **Federal Register**'s publication procedures provide that only proposed rules may be published in the proposed rule section of the **Federal Register**. OST also believes that interested parties are more likely to read the final rule section than the proposed rule section of the **Federal Register**. The public is used to providing comments in response to interim final rules. Nevertheless, in response to the concerns raised, we plan to work with the **Federal Register** to give the public as much notice as possible of the opportunity to provide comments. For example, we plan to have the "action" caption read "direct final rule" and include language in the summary and preamble so that interested parties will be aware of their right to comment.

Akzo Nobel Chemicals, Panhandle Eastern Corp., and ATA all expressed concern over whether, in practice, the public would have a sufficient opportunity to comment on a direct final rule before the rule became final. Panhandle suggested that OST consider establishing a standard comment period, such as 30 days, between the date of publication and the rule's effective date. Panhandle argued that this would better ensure that those wishing to submit comments on the direct final rule would have sufficient time to do so. ATA commented that a short comment period might create problems since some direct final rules may have complex implications that require time to evaluate before they can be determined to be noncontroversial. ATA argued that this possibility was particularly true for direct final rules that addressed technical standards.

OST normally provides at least a 60-day comment period for all rulemakings. In cases where OST provides a shorter comment period for a proposed rule, OST explains in the preamble why a shorter comment period is necessary. In practice, it is in OST's interest to provide a comment period of sufficient length to allow interested parties to determine whether they wish or need to submit adverse comments. Too short a comment period could stymie the direct final rule process by forcing commenters to err on the side of caution and file an intent to submit adverse comment to stop the direct final rule process in cases involving any uncertainty of the effect of a direct final rule.

Akzo also expressed concern that the proposed procedures did not specify any particular comment period. Akzo proposed that language be included in the direct final rule procedure that allows potentially impacted parties to submit a notice of preliminary estimate of significant impact that would halt the expedited rulemaking process and require OST to seek comment. OST believes that its procedures adequately address this issue and that such a notice would be redundant. The timely submission of an adverse comment or a notice of intent to submit adverse comment will immediately halt the direct final rulemaking procedure and trigger the rule's withdrawal. OST sees no need to include an additional, essentially identical, procedure. If a party believes it needs more time to decide whether to file even a notice of intent to file adverse comment, it can ask OST to extend the comment period (and state that, if we do not, we should treat this request as a notice of intent). We stress that we do not intend to use these procedures for complex, potentially controversial matters, and it is to our disadvantage if we misuse it and have to take extra steps as a result.

ATA also expressed concern that explanations of proposed regulatory actions might suffer under the direct final rule procedures. Our response is simply that we will try to avoid this and remind ATA that, once again, this procedure will only be used for minor, noncontroversial rules, which will not usually require much explanation. Further, it is in OST's interest to give clear explanations for rules. According to the Administrative Procedure Act (APA) (5 U.S.C. 553(c)), OST must provide a concise general statement of the basis and purpose of any rule, including a direct final rule. The use of direct final rulemaking procedures in no way excuses OST from complying with the APA and adequately explaining its action in the preamble to the direct final rule. Further, OST has every incentive to ensure that the direct final rule adequately explains any regulatory action since misunderstandings over the effect of a rule could cause members of the public to unnecessarily file an adverse comment or an intent to submit adverse comment in cases involving uncertainty, effectively resulting in the rule's withdrawal and creating more work for OST.

Advocates expressed general support for the direct final rule making process, but were concerned with the use of this procedural device for the adoption of technical standards developed by private organizations, particularly by the Department's modal administrations. However, these direct final rulemaking procedures apply only to rulemakings done in OST. Rulemakings done in DOT's modal administrations, such as FAA, are governed by each modal administration's own rules. We agree that technical standards, for the most part, are not ministerial issues and thus, very few, will be subject to the direct final rule procedure. In addition, if an objectionable technical standard is published, the public may object in writing and the usual NPRM process will commence immediately.

Advocates also asked for clarification as to whether the text of the adverse comment needs to be submitted to OST within the comment period when notice of intent to submit adverse comment has been filed. The text of the comment does not have to be submitted within the comment period. It may be submitted later, if at all. As long as the written notice of intent to file an adverse comment is received by OST within the comment period, the direct final rule is withdrawn and, if appropriate, the usual NPRM process is initiated and a full notice and comment period begins, with its own deadline for comment submission. Any adverse comment received would be placed in the docket and considered in the NPRM or as part of the process for deciding on a final rule.

Advocates also expressed concern that OST could abuse and exploit the direct final rule procedure. We would like to assure Advocates and the public that the use of this procedure by OST is purely to save time and expense in its enactment of noncontroversial rules where no adverse comment is anticipated. If OST tries to use this procedure for rules that are in fact controversial, adverse comments serve as a safeguard to force the NPRM process. In such a case, OST ends up with more work than if it proposed the rule the usual way, hence the incentive is to use the process only for rules that are truly anticipated to be noncontroversial.

Panhandle asked whether a request for a clarification of a direct final rule would be considered an adverse comment for purposes of terminating a direct final rule. Requests for clarification of direct final rules will not be considered adverse comments. OST notes, however, that during pendency of the comment period, it will answer requests for clarification of rules. If the party requesting the clarification believes that the clarification is insufficient, the party may send a notice of adverse comment, which will end the direct final rule process.

In its comments in support of the direct final rulemaking procedure, EOC stated that it believed the direct final rulemaking procedure would apply to safety regulations issued by the Research and Special Programs Administration (RSPA). This is not the case. RSPA has its own direct final rulemaking procedure (*see* 49 CFR part 190.339) and RSPA regulations are not issued under OST's procedures. In light of Enron's comment, OST is taking this opportunity to update 49 CFR part 5 to conform to current practice. In addition, OST is updating the applicability section of part 5 to remove the reference to the United States Coast Guard. Under the Homeland Security Act of 2002 (Pub. L. 107–296), the Coast Guard was transferred from the Department of Transportation to the Department of Homeland Security.

Regulatory Analyses and Notices

OST has determined that this action is not a significant regulatory action under Executive Order 12866 or under the Department's Regulatory Policies and Procedures. There are no costs associated with this rule. There will be some savings in **Federal Register** publication costs and efficiencies for the public and OST personnel in eliminating duplicative reviews. This rule will lessen the number of documents they must review and comment on. Finally, it will not be used that often and not for rules OST anticipates will warrant comment.

Because this rule will only apply to actions that are not expected to result in adverse comment and because it will eliminate an unnecessary second round of review, OST certifies that this rule will not have a significant economic impact on a substantial number of small entities. Moreover, any impact should be positive. OST also has determined that there are not sufficient federalism implications to warrant consultation on the preparation of a federalism impact statement.

Paperwork Reduction Act

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

Unfunded Mandates Reform Act of 1995

OST has determined that the requirements of Title II of the Unfunded Mandates Reform Act of 1995 do not apply to this rulemaking.

List of Subjects in 49 CFR Part 5

Administrative practice and procedure.

■ For the reasons set forth in the preamble, the Office of the Secretary amends 49 CFR part 5 as follows:

PART 5—RULEMAKING PROCEDURES

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

Authority: Sec. 9, 80 Stat. 944 (49 U.S.C. 1657).

■ 2. In part 5, subpart A, revise paragraph (a) of § 5.1 to read as follows:

§ 5.1 Applicability.

(a) This part prescribes general rulemaking procedures that apply to the issuance, amendment, and repeal of rules of the Office of the Secretary of Transportation. It does not apply to rules issued by the Federal Aviation Administration, Federal Highway Administration, Federal Railroad Administration, Federal Transit Administration, Maritime Administration, National Highway Traffic Safety Administration, Research and Special Programs Administration, St. Lawrence Seaway Development Corporation, or Federal Motor Carrier Safety Administration.

* * * * *

■ 3. In part 5, subpart C, amend § 5.21 by adding paragraph (d), to read as follows:

§ 5.21 General.

* * * * *

(d) For rules for which the Secretary determines that notice is unnecessary because no adverse public comment is anticipated, the direct final rulemaking procedure described in § 5.35 of this subpart may be followed.

■ 4. In part 5, subpart C, add a new § 5.35, to read as follows:

§ 5.35 Procedures for direct final rulemaking.

(a) Rules that the Secretary judges to be noncontroversial and unlikely to result in adverse public comment may be published as direct final rules. These include noncontroversial rules that:

(1) Affect internal procedures of the Office of the Secretary, such as filing requirements and rules governing inspection and copying of documents,

(2) Are nonsubstantive clarifications or corrections to existing rules,

(3) Update existing forms,

(4) Make minor changes in the substantive rules regarding statistics and reporting requirements,

(5) Make changes to the rules implementing the Privacy Act, and

(6) Adopt technical standards set by outside organizations.

(b) The **Federal Register** document will state that any adverse comment or notice of intent to submit adverse comment must be received in writing by the Office of the Secretary within the specified time after the date of publication and that, if no written adverse comment or written notice of intent to submit adverse comment is received, the rule will become effective a specified number of days after the date of publication.

(c) If no written adverse comment or written notice of intent to submit adverse comment is received by the Office of the Secretary within the specified time of publication in the **Federal Register**, the Office of the Secretary will publish a notice in the **Federal Register** indicating that no adverse comment was received and confirming that the rule will become effective on the date that was indicated in the direct final rule.

(d) If the Office of the Secretary receives any written adverse comment or written notice of intent to submit adverse comment within the specified time of publication in the **Federal Register**, a notice withdrawing the direct final rule will be published in the final rule section of the **Federal Register** and, if the Office of the Secretary decides a rulemaking is warranted, a notice of proposed rulemaking will be published in the proposed rule section of the **Federal Register**.

(e) An "adverse" comment for the purpose of this subpart means any comment that the Office of the Secretary determines is critical of the rule, suggests that the rule should not be adopted, or suggests a change that should be made in the rule. A comment suggesting that the policy or requirements of the rule should or should not also be extended to other Departmental programs outside the scope of the rule is not adverse.

Issued in Washington, DC, on January 13, 2004.

Norman Y. Mineta,

Secretary.

[FR Doc. 04–1939 Filed 1–29–04; 8:45 am]

BILLING CODE 4910–62–P

Proposed Rules

Federal Register
Vol. 69, No. 20
Friday, January 30, 2004

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.

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[FL–87–200407; FRL–7616–3]

Approval and Promulgation of Implementation Plans: Florida: Citrus Juice Processing

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed conditional approval.

SUMMARY: EPA is proposing to conditionally approve a State Implementation Plan (SIP) revision submitted by the State of Florida (the "State") on January 30, 2001, with additional material submitted on July 16, 2002 and January 31, 2003. This notice also identifies those changes that must be made to the Florida statute and regulation that underlies the State's program in order for EPA to find the SIP submission approvable. Florida's submittal is for an innovative strategy to regulate air pollutant emissions from citrus juice processing facilities. The program is designed to reduce emissions of smog forming compounds, known as volatile organic compounds (VOC), through the recovery of citrus oils. The proposed SIP revision consists of a new Florida statute and implementing regulations that set emission limits for existing and new equipment at the twenty-six existing citrus juice processing facilities in Florida. EPA is proposing to approve Florida's innovative citrus juice processing program as a SIP revision with the condition that Florida correct the deficiencies identified in this action as Title I Requirements and submit approvable revisions to EPA within 12 months. EPA will address the State's formal request for a Title V program revision as a separate action.

DATES: Written comments must be received on or before March 1, 2004 at the address given below.

ADDRESSES: If you submit comments on this proposed action, they must be sent to: Ms. Kelly Fortin at the U. S. Environmental Protection Agency, Region 4 Air Planning Branch, 61 Forsyth Street SW., Atlanta, Georgia 30303–8960. Comments may also be submitted electronically, or through hand delivery/courier. Please follow the detailed instructions described in sections IV.B.1. through 3. of the **SUPPLEMENTARY INFORMATION** section.

FOR FURTHER INFORMATION CONTACT: Ms. Kelly Fortin, Air Permitting Section, Air Planning Branch, Air, Pesticides and Toxics Management Division, U.S. Environmental Protection Agency, Region 4, 61 Forsyth Street SW., Atlanta, Georgia 30303–8960. The telephone number is (404) 562–9117. Ms. Fortin can also be reached via electronic mail at: *fortin.kelly@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. Regulated Entities

The proposed changes to the Florida SIP would apply to the 26 existing citrus juice processing facilities in the State of Florida.

II. EPA's Action

A. What Action Is EPA Proposing Today?

EPA is proposing a conditional approval under section 110(k)(4) of the CAA. EPA may conditionally approve a plan based on a commitment from the State to adopt specific enforceable measures within one year from the effective date of final conditional approval. If the State fails to meet its commitment within the one-year period, the approval is treated as a disapproval. Because the revisions would materially alter the existing SIP approved rule, the State must make a SIP submittal. As with any SIP revision, the State must provide notice and public hearing on the proposed changes.

If the State fails to adopt and submit the specified measures by the end of one year (from the final conditional approval), or fails to make a submittal, EPA will issue a finding of disapproval. If EPA determines that the rule is approvable, EPA will propose approval of the rule in the **Federal Register**. EPA will conditionally approve a certain rule only once.

B. Why Is EPA Proposing This Action?

EPA is taking this action in response to a request from the Florida Department of Environmental Protection (FDEP) to revise Florida's SIP and Title V operating permit program to include an alternative regulatory program for citrus juice processing facilities. FDEP's complete submittal, received by EPA on July 29, 2002, includes a new citrus statute (Florida Statute 403.08725), which the State adopted in July 2000 and amended on June 12, 2003, as well as draft implementing regulations and supporting material. FDEP formally adopted these implementing regulations in December 2002. 62–210.340 F.A.C. FDEP also requested that the statute and regulation be processed by EPA pursuant to the Joint EPA/State Agreement to Pursue Regulatory Innovation between EPA and the Environmental Council of the States ("ECOS"). 63 FR 24784. After a detailed review, EPA responded to FDEP with letters, dated September 18, 2002, and April 24, 2003, listing several conditions that must be rectified in order for EPA to incorporate the program into the Florida SIP. On January 31, 2003, FDEP made a supplemental submittal outlining their intent to make necessary statutory and regulatory revisions to the program.

C. What Does the Florida Citrus ECOS Proposal Require or Allow?

The program requires the 26 existing juice processing facilities in Florida to comply with specified terms in the statute when they construct, operate, and modify air emissions units. For some units, these conditions are different from those required by the conventional construction and operating permit requirements required by the SIP-approved Florida regulations that currently apply to citrus juice processing facilities. The statute requires a 65% recovery (50% the first year) of d-limonene oil from peel processed through the peel dryer. This reduction will decrease emissions of VOC from these facilities by approximately 38%. The citrus facilities can comply with the VOC emission limitations through a combination of emission controls, pollution prevention, and emission credits that can be generated through over-control of the juice processing facilities. The statute includes requirements for emissions of VOC, nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM), for existing units and for new units. New units include units that are modified or are relocated. The program also incorporates all applicable federal standards (such as maximum achievable control technology (MACT) for hazardous air pollutants and New Source Performance Standards (NSPS)). The statute and implementing regulations will be considered a general permit for the purpose of Title V of the Clean Air Act (CAA).

D. When Will This Program Take Effect?

Per the Florida statute, the program will be State effective on October 1, 2004. If the EPA does not approve the program as a revision to Florida's SIP and Title V program by January 31, 2005, the Florida statute will expire, and the applicable requirements will revert back to those of the conventional programs.

E. What Facilities Must Comply With the New Program?

The 26 existing juice processing facilities in Florida are the only facilities to which the new statute and regulations apply. Modifications, consolidation, and new units at existing sites will be covered by the program and must meet the requirements for "new units." New or "greenfield" processing facilities will not be covered and will be subject to the conventional Florida regulations, as applicable. Likewise, any units not specifically listed in the regulations (*i.e.* those not directly related to citrus juice processing) are not covered by the program, but remain subject to current SIP approved requirements. In addition, EPA is proposing approval of this program only for use by facilities in attainment areas (those areas meeting the National Ambient Air Quality Standards (NAAQS)). Should an area that contains an existing juice processing facility be designated as nonattainment, such facility would need to comply with the State's SIP approved nonattainment requirements, or a SIP approved version of this rule that has been revised to meet the CAA requirements for an area that has not attained the NAAQS (a "nonattainment" area).

F. What Type of Air Pollution Comes From Citrus Juice Processing Facilities?

The citrus juice facilities produce juice, as well as other by-products associated with juice production, such as animal feed pellets and citrus oils. Some facilities are capable of producing excess electric power for sale. One facility also has a container glass plant to make juice bottles. Emissions from the citrus juice processing plants come primarily from feed mill dryers and coolers, boilers, combustion turbines, and a container glass furnace. Regulated pollutants emitted by the facilities include VOC, NO_X, SO_2, PM, carbon monoxide (CO) and hazardous air pollutants (HAP) (primarily methanol and formaldehyde).

G. What Are the Benefits of This Proposal?

An analysis conducted by the FDEP concluded that the proposed citrus program will provide greater reductions in VOC, SO_2 and PM than can be obtained under the conventional State permitting program. VOC emissions reductions will be greater because all existing facilities that operate peel driers will be subject to emissions limits for VOC and will be required to enhance peel oil recovery or trade with other citrus plants to get VOC emissions credits. SO_2 and PM emissions will be reduced because all facilities will be subject to a limit on the sulfur content of fuels used at each facility. In contrast, under the conventional program (New Source Review (NSR)), facilities would not be required to reduce emissions until they actually made a change at the facility that would cause an emissions increase.

H. Is the State's Proposal Consistent With Applicable Laws?

This program is designed to replace the current State regulations that meet the Prevention of Significant Deterioration (PSD) and Title V requirements of the CAA, 40 CFR 51.160–51.163 and 51.166 and 40 CFR part 70 respectively, for existing citrus juice processing facilities. As proposed, the program does not meet all of the requirements of the CAA and applicable federal regulations. Hence, EPA is not taking any final action on the Florida program at this time.

Our proposed approval is conditioned upon FDEP making specific changes to the State statute and regulations, and submitting the approvable changes to EPA. Because these regulatory requirements are different than what is required by Florida's current SIP and Title V program, EPA must approve them as revisions to Florida's SIP and Title V program, so that they become federally enforceable requirements for these facilities. EPA will follow the statutory requirements of the CAA for notice and comment rulemaking when taking these actions.

I. Why Is EPA Proposing This Special Approval for the Florida Citrus Processing Industry?

Florida initiated this innovations project in accordance with the joint EPA/State Agreement to Pursue Regulatory Innovation developed by EPA and ECOS. These projects are experimental in nature and are designed to attempt to bring about environmental benefits through non-traditional regulatory means. EPA is proposing conditional approval of this project because we believe that equivalent or superior environmental performance will be achieved, while the administrative burden on both the State and the regulated community may be decreased. More specifically, we believe, this program, when fully approved, will meet the seven overarching principles of ECOS: (1) Experimentation; (2) environmental performance; (3) smarter approach; (4) stakeholder involvement; (5) measuring and verifying results; (6) accountability; and (7) State/EPA partnership. Further information on the goals and objectives of the ECOS agreement can be found at: *http://www.epa.gov/reinvent.*

J. How Will This Program Ensure Environmental Performance?

Innovations projects are, by design, experimental. Per the ECOS guidelines, these projects contain performance measures and program review criteria to evaluate their success and environmental impact. For example, the Florida citrus program, if approved, will undergo comprehensive review after three years of implementation and again after six years. If the project does not produce environmental results equivalent to or better than the conventional approach, per the regulations, it will be terminated and facilities will be subject to conventional requirements. The FDEP will also solicit public and stakeholder comment for program improvement.

K. What Happens Next?

After consideration of any comments received on this "proposal," EPA will publish a notice indicating if this conditional approval is final or withdrawn. If the conditional approval is granted, the FDEP will then have one year from the effective date of the conditional approval to complete and submit to EPA the necessary program revisions. Revisions to the Florida Title V program will be proposed following EPA's receipt of an updated program submittal that includes the necessary changes to meet the requirements of Title V. Hence, this proposed action is only in response to the State's SIP submittal and is not a proposed action on the State's proposed revisions to the Title V program for the citrus facilities. After EPA receives the State's submittal, required by the conditional approval, EPA will review the changes to ensure that they remedy the deficiencies identified in this notice. If EPA believes these changes are approvable, EPA will publish a proposed action to approve the SIP and Title V revisions, again soliciting public comment. If EPA does not approve the program as a revision to Florida's SIP and Title V program by January 31, 2005, the Florida citrus statute will expire.

L. What Specific Changes Must Be Made to the Program?

1. *Title I Requirements:* The following changes must be made to the citrus program and submitted to EPA in order for the program to meet the requirements of the CAA and implementing regulations at 40 CFR 51.160–51.164 and 51.166:

i. *Fuel Sulfur Content:* The results of the required modeling analyses submitted with the proposed program indicate violations of the NAAQS and PSD Class II area increments for SO_2 under possible industry consolidation scenarios. The Florida statute must require that the sulfur content of the fuel used at the subject facilities not exceed 0.1% at all new and existing units. This level is also required to meet the control technology requirements of the CAA and to ensure the environmental performance of the program. On June 12, 2003, the State adopted changes to the statute to limit the sulfur content of the fuel. These revisions must be submitted to EPA for approval.

ii. *Reduced PM–10 Emissions:* The results of the required modeling analyses submitted with the proposed program indicate violations of the NAAQS and PSD Class II area increments for particulate matter (PM–10) under possible industry consolidation scenarios. The statute must contain revised PM–10 limits for new process steam boilers, as well as increase in stack height for all new boilers and coolers, to eliminate modeled violations. On June 12, 2003, the State adopted changes to the statute to reduce emissions of PM–10 and associated impacts. These revisions must be submitted to EPA for approval.

iii. *Production Cap:* The citrus program will apply throughout the juice processing sector in Florida. Existing facilities will be able to make modifications and add new equipment without triggering conventional preconstruction requirements as long as they meet the requirements set out in the program. However, unlike conventional "cap and trade" type programs, the program, as proposed, does not "cap" emissions. The submittal must be revised to provide an industry-wide limit on production to ensure protection of the NAAQS, PSD increments, and Class I areas. On June 12, 2003, the State adopted a statutory change that includes a limit on the amount of fruit processed that is consistent with the "fruit availability" assumptions that were modeled and analyzed in the proposal. The revised statute and implementing regulations must be submitted to EPA for approval.

iv. *Regulated and Toxic Pollutants:* As submitted, the program does not address all regulated pollutants, as required by Titles I, III and V of the CAA. Specifically, the citrus facilities are known to produce CO, methanol and formaldehyde at levels that may exceed the significance thresholds. On June 12, 2003, the State adopted a statutory change that gave FDEP statutory authority to develop regulations for these pollutants that will be applicable requirements for the subject facilities. The revised statute and implementing regulations must be submitted to EPA for approval.

2. *Title V and ECOS Requirements:* EPA will formally address changes that are required to meet the requirements of Title V and the ECOS agreement in a separate **Federal Register** action. We are, however, including a summary of these below in order to provide the State and interested parties with as much notice as possible. As a practical matter, the citrus program represents a "package" of SIP and Title V changes. The following revisions must be made in order for the program to receive approval as part of the Florida Title V program and to meet the requirements of the ECOS agreement:

i. *Opportunity for EPA objection and subsequent public petition and judicial review of the general permit:* The statute and implementing regulations, as submitted, do not specifically provide an opportunity for EPA objection and subsequent public petition and judicial review as required under the general permit provisions of Title V (CAA. 502(b)(5), 502(b)(6) and 504(d)). However, under the State's existing approved Title V program and implementing regulations, consistent with Title V and the implementing federal regulations, these requirements should occur after all the applicable requirements have been identified for the subject facilities. On June 12, 2003, the State adopted a statutory change that provides FDEP with the authority to adopt public participation procedures consistent with the requirements of Title V. EPA must receive the necessary statutory and regulatory changes prior to approving the program as a revision to the State's Title V program.

ii. *Performance measures:* Pursuant to the ECOS agreement, performance measures must be developed to measure and verify results and ensure the environmental accountability of the program. Per the January 31, 2003 letter that EPA received from Howard Rhodes, FDEP indicated that the State believes that the appropriate performance measures are those that compare the overall industry-wide results from the alternative program with those that would have occurred under the conventional NSR program. The State also indicated that FDEP intends to review the program's performance in aggregate to determine if the program is successful. The State must submit the adopted performance criteria to EPA for review and approval.

iii. *Program Review and Termination:* Due to the experimental nature of the program, the regulations must require program review and evaluation on an established schedule. On June 12, 2003, the State adopted a statutory change to require an analysis within three years of program implementation to determine whether the program should continue or be terminated and revert to conventional NSR. In the event the program continues, a second analysis will be conducted within six years of program implementation. Each review must be of the same nature and scope as that submitted in the original proposal and must include, among other things, a specific consideration of the environmental impact of industry consolidation and modification, as well as applicable new or improved technologies for new or modified facilities. The final report must be provided to the State legislature, to EPA, and to the public. In addition, as currently specified in the program, at five year intervals from the program's initiation, Florida must solicit public comment on the program's effectiveness.

The statute must also include a termination clause and mitigation in the event of program failure. FDEP has indicated that they intend to submit requirements that would require mitigation through recovery of emissions reductions that would have otherwise occurred under conventional NSR. These reductions would not necessarily be required at the specific facility that would have otherwise had to have them. However, such reductions would be enforceable as a practical matter. The State has also indicated that FDEP will be able, through its tracking system, to identify facilities that would otherwise be subject to the conventional programs so that this calculation can be made. On June 12, 2003, the State adopted statutory changes that include the above requirements. The revised statute and implementing regulations must be submitted to EPA for approval.

III. Proposed Action

EPA is proposing to approve the Florida SIP revision, consisting of an innovative strategy to create a alternative program for regulating the existing citrus juice industry, which was submitted on January 30, 2001, with additional material submitted on July 16, 2002, and January 31, 2003, with the condition that Florida correct the deficiencies described in this notice. EPA is taking this action pursuant to our authority in section 110(k)4 of the CAA.

IV. General Information

A. How Can I Get Copies of This Document and Other Related Information?

1. The Regional Office has established an official public rulemaking file available for inspection at the Regional Office. EPA has established an official public rulemaking file for this action under Docket Control No. FL–87. The official public file consists of the documents specifically referenced in this action, any public comments received, and other information related to this action. Although a part of the official docket, the public rulemaking file does not include Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. The official public rulemaking file is the collection of materials that is available for public viewing at the, Air Planning Branch, Air, Pesticides and Toxics Management Division, U.S. Environmental Protection Agency, Region 4, 61 Forsyth Street, SW, Atlanta, Georgia 30303–8960. EPA requests that if at all possible, you contact the person listed in the **FOR FURTHER INFORMATION CONTACT** section to schedule your inspection. The Regional Office's official hours of business are Monday through Friday, 9 to 3:30, excluding federal holidays.

2. Copies of the State submittal and EPA's technical support document are also available for public inspection during normal business hours, by appointment at the State Air Agency: Florida Department of Environmental Protection, Division of Air Resources Management, 2600 Blair Stone Road, Tallahassee, Florida 32399–2400.

3. Electronic Access. You may access this **Federal Register** document electronically through the Regulation.gov Web site located at *http://www.regulations.gov* where you can find, review, and submit comments on Federal rules that have been published in the **Federal Register**, the Government's legal newspaper, and are open for comment.

For public commenters, it is important to note that EPA's policy is that public comments, whether submitted electronically or in paper, will be made available for public viewing at the EPA Regional Office, as EPA receives them and without change, unless the comment contains copyrighted material, CBI, or other information whose disclosure is restricted by statute. When EPA identifies a comment containing copyrighted material, EPA will provide a reference to that material in the version of the comment that is placed in the official public rulemaking file. The entire printed comment, including the copyrighted material, will be available at the Regional Office for public inspection.

B. How and To Whom Do I Submit Comments?

You may submit comments electronically, by mail, or through hand delivery/courier. To ensure proper receipt by EPA, identify the appropriate rulemaking identification number by including the text, "Public comment on proposed rulemaking Docket Control No. FL–87," in the subject line on the first page of your comment. Please ensure that your comments are submitted within the specified comment period. Comments received after the close of the comment period will be marked "late." EPA is not required to consider these late comments.

1. *Electronically.* If you submit an electronic comment as prescribed below, EPA recommends that you include your name, mailing address, and an e-mail address or other contact information in the body of your comment. Also include this contact information on the outside of any disk or CD ROM you submit, and in any cover letter accompanying the disk or CD ROM. This ensures that you can be identified as the submitter of the comment and allows EPA to contact you in case EPA cannot read your comment due to technical difficulties or needs further information on the substance of your comment. EPA's policy is that EPA will not edit your comment, and any identifying or contact information provided in the body of a comment will be included as part of the comment that is placed in the official public docket. 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.

i. *E-mail.* Comments may be sent by electronic mail (e-mail) to *Fortin.Kelly@epa.gov*. Please include the text, "Public comment on proposed rulemaking Docket Control No. FL–87," in the subject line. EPA's e-mail system is not an "anonymous access" system. If you send an e-mail comment directly without going through Regulations.gov, EPA's e-mail system automatically captures your e-mail address. E-mail addresses that are automatically captured by EPA's e-mail system are included as part of the comment that is placed in the official public docket.

ii. *Regulation.gov.* Your use of Regulation.gov is an alternative method of submitting electronic comments to EPA. Go directly to Regulations.gov at *http://www.regulations.gov*, then select Environmental Protection Agency at the top of the page and use the go button. The list of current EPA actions available for comment will be listed. Please follow the online instructions for submitting comments. The system is an "anonymous access" system, which means EPA will not know your identity, e-mail address, or other contact information unless you provide it in the body of your comment.

iii. *Disk or CD ROM.* You may submit comments on a disk or CD ROM that you mail to the mailing address identified in section 2, directly below. These electronic submissions will be accepted in WordPerfect, Word or ASCII file format. Avoid the use of special characters and any form of encryption.

2. *By Mail.* Send your comments to: Kelly Fortin, Air Permits Section, Air Planning Branch, Air, Pesticides and Toxics Management Division, U.S. Environmental Protection Agency, Region 4, 61 Forsyth Street, SW, Atlanta, Georgia 30303–8960. Please include the text, "Public comment on proposed rulemaking Docket Control No. FL–87," in the subject line on the first page of your comment.

3. *By Hand Delivery or Courier.* Deliver your comments to: Kelly Fortin, Air Permits Section, Air Planning Branch, Air, Pesticides and Toxics Management Division 12th floor, U.S. Environmental Protection Agency, Region 4, 61 Forsyth Street, SW., Atlanta, Georgia 30303–8960. 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, 9 to 3:30, excluding Federal holidays.

C. How Should I Submit CBI to the Agency?

Do not submit information that you consider to be CBI electronically to EPA.

You may claim information that you submit to EPA as CBI by marking any part or all of that information as CBI (if you submit CBI on disk or CD ROM, mark the outside of the disk or CD ROM as CBI and then identify electronically within the disk or CD ROM the specific information that is CBI). Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

In addition to one complete version of the comment that includes any information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the official public regional rulemaking file. If you submit the copy that does not contain CBI on disk or CD ROM, mark the outside of the disk or CD ROM clearly that it does not contain CBI. Information not marked as CBI will be included in the public file and available for public inspection without prior notice. If you have any questions about CBI or the procedures for claiming CBI, please consult the person identified in the **FOR FURTHER INFORMATION CONTACT** section.

D. What Should I Consider as 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.
2. Describe any assumptions that you used.
3. Provide 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 your estimate.
5. Provide specific examples to illustrate your concerns.
6. Offer alternatives.
7. Make sure to submit your comments by the comment period deadline identified.
8. To ensure proper receipt by EPA, identify the appropriate regional file/rulemaking identification number in the subject line on the first page of your response. It would also be helpful if you provided the name, date, and **Federal Register** citation related to your comments.

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 CAA. 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 CAA. 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 CAA. 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, Intergovernmental relations, Nitrogen dioxide, Ozone, Particulate matter, Reporting and recordkeeping requirements, Volatile organic compounds.

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

Dated: January 21, 2004.

A. Stanley Meiburg,

Acting Regional Administrator, Region 4.

[FR Doc. 04–1977 Filed 1–29–04; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 260 and 261

[RCRA—2003–0004; FRL–7615–4]

RIN 2050–AE51

Hazardous Waste Management System: Identification and Listing of Hazardous Waste: Conditional Exclusions From Hazardous Waste and Solid Waste for Solvent-Contaminated Industrial Wipes; Extension of Comment Period

AGENCY: Environmental Protection Agency.

ACTION: Proposed rule; extension of comment period.

SUMMARY: The U.S. Environmental Protection Agency (EPA) is extending the comment period for the proposed rule entitled "Proposed Conditional Exclusions from Hazardous and Solid Waste for Solvent Contaminated Industrial Wipes," which appeared in the **Federal Register** on November 20, 2003 (68 FR 65586). The public comment period for this proposed rule was to end on February 18, 2004. The purpose of this notice is to extend the comment period to end on March 19, 2004.

DATES: EPA will accept public comments on this proposed regulation until March 19, 2004. Comments submitted after this date will be marked "late" and may not be considered.

ADDRESSES: Comments may be submitted by mail to: OSWER Docket, Environmental Protection Agency, Mailcode: 5305T, 1200 Pennsylvania Avenue, NW., Washington, DC 20460, Attention Docket ID No. RCRA–2003–0004. Comments may also be submitted electronically, or through hand delivery/courier; follow the detailed instructions as provided below in the **SUPPLEMENTARY INFORMATION** section of this document.

FOR FURTHER INFORMATION CONTACT: For general information on the proposed regulation, contact the RCRA Call Center at (800) 424–9346 or TDD (800) 553–7672 (hearing impaired). In the Washington, DC, metropolitan area, call (703) 412–9810 or TDD (703) 412–3323. For more detailed information on specific aspects of this rulemaking, contact Kathy Blanton at (703) 605–0761 (*blanton.katherine@epa.gov*).

SUPPLEMENTARY INFORMATION: The proposed rule that is the subject of this notice, and which was published in the **Federal Register** on November 20, 2003 (68 FR 65586), proposed a conditional exclusion from the definition of solid waste for industrial wipes that are contaminated with solvent and that are sent to laundries or dry cleaners for cleaning and reuse. It also proposed a conditional exclusion from the definition of hazardous waste for industrial wipes that are contaminated with solvent and are sent to disposal.

The comment period for the proposed rule was scheduled to end on February 18, 2004. However, a public commenter (the Utilities Solid Waste Activities Group) has requested that EPA extend the comment period, noting that it is submitting comments on several other EPA rulemaking proposals with comment periods ending close to that date. EPA believes this request is reasonable. EPA also notes that this rule is not subject to any statutory or judicial deadlines. We are therefore extending the comment period for this proposal until March 19, 2004.

How and to Whom Do I Submit Comments?

You may submit comments electronically, by mail, or through hand delivery/courier. To ensure proper receipt by EPA, identify the appropriate docket identification number in the subject line on the first page of your comment. Please ensure that your comments are submitted within the specified comment period. Comments received after the close of the comment period will be marked "late." EPA is not required to consider these late comments.

Electronically

If you submit an electronic comment as prescribed below, EPA recommends that you include your name, mailing address, and an e-mail address or other contact information in the body of your comment. Also include this contact information on the outside of any disk or CD–ROM you submit, and in any cover letter accompanying the disk or CD–ROM. This ensures that you can be identified as the submitter of the comment and allows EPA to contact you in case EPA cannot read your comment due to technical difficulties or needs further information on the substance of your comment. EPA's policy is that EPA will not edit your comment, and any identifying or contact information provided in the body of a comment will be included as part of the comment that is placed in the official public docket, and made available in EPA's electronic public docket. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment.

Your use of EPA's electronic public docket to submit comments to EPA electronically is EPA's preferred method for receiving comments. Go directly to EPA Dockets at *http://www.epa.gov/edocket*, and follow the online instructions for submitting comments. To access EPA's electronic public docket from the EPA Internet Home Page, select "Information Sources," "Dockets," and "EPA Dockets." Once in the system, select "search," and then key in Docket ID No. RCRA–2003–0004. The system is an "anonymous access" system, which means EPA will not know your identity, e-mail address, or other contact information unless you provide it in the body of your comment.

Comments may be sent by electronic mail (e-mail) to *rcra-docket@epa.gov*, Attention Docket ID No. RCRA–2003–0004. In contrast to EPA's electronic public docket, EPA's e-mail system is not an "anonymous access" system. If you send an e-mail comment directly to the Docket without going through EPA's electronic public docket, EPA's e-mail system automatically captures your e-mail address. E-mail addresses that are automatically captured by EPA's e-mail system are included as part of the comment that is placed in the official public docket, and made available in EPA's electronic public docket.

You may submit comments on a disk or CD–ROM that you mail to the mailing address identified in the following paragraph. These electronic submissions will be accepted in WordPerfect or ASCII file format. Avoid the use of special characters and any form of encryption.

By Mail

Send your comments to: OSWER Docket, EPA Docket Center, Mailcode: 5305T, Environmental Protection Agency, 1200 Pennsylvania Avenue, NW., 20460, Attention Docket ID Number RCRA–2003–0004.

By Hand Delivery or Courier

Deliver your comments to: OSWER Docket, EPA West Building, Room B102, 1301 Constitution Avenue, NW., Washington, DC., Attention Docket ID No. RCRA–2003–0004. Such deliveries are only accepted during the Docket's normal hours of operation (8:30 a.m. to 4:30 p.m. Monday through Friday, excluding legal holidays).

Dated: January 22, 2004.

Robert Springer,

Director, Office of Solid Waste.

[FR Doc. 04–1972 Filed 1–29–04; 8:45 am]

BILLING CODE 6560–50–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Medicare & Medicaid Services

42 CFR Parts 412, 413, and 424

[CMS–1213–N]

RIN 0938–AL50

Medicare Program; Prospective Payment System for Inpatient Psychiatric Facilities; Extension of Comment Period

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

ACTION: Notice of extension of comment period for proposed rule.

SUMMARY: This document extends the comment period for a proposed rule, "Medicare Program; Prospective Payment System for Inpatient Psychiatric Facilities" published in the **Federal Register** (68 FR 66920) on November 28, 2003. That rule proposes a prospective payment system for Medicare payment of inpatient hospital services furnished in psychiatric hospitals and psychiatric units of acute care hospitals. The prospective payment system described in the proposed rule would replace the current reasonable cost-based payment system under the Tax Equity and Fiscal Responsibility Act of 1992 (TEFRA). The comment period that would have closed on January 27, 2004 is extended 30 days.

DATES: The comment period is extended to 5 p.m. on February 26, 2004.

ADDRESSES: In commenting, please refer to file code CMS–1213–P. Because of staff and resource limitations, we cannot accept comments by facsimile (FAX) transmission. 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–1213–P, P.O. Box 8012, Baltimore, MD 21244–8012.

Please allow sufficient time for mailed comments to be received timely in the event of delivery delays.

If you prefer, you may deliver (by hand or courier) your written comments (one original and two copies) to one of the following addresses:

Room 445–G, Hubert H. Humphrey Building, 200 Independence Avenue, SW., Washington, DC 20201, or

Room C5–14–03, 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 could be considered late.

For information on viewing public comments, see the beginning of the **SUPPLEMENTARY INFORMATION** section.

FOR FURTHER INFORMATION CONTACT: Janet Samen, (410) 786–4533.

SUPPLEMENTARY INFORMATION:

Inspection of Public Comments: Comments received timely will be available for public inspection as they are received, generally beginning approximately 4 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 (410) 786–9994.

Copies: To order copies of the **Federal Register** containing this document, send your request to: New Orders, Superintendent of Documents, P.O. Box 371954, Pittsburgh, PA 15250–7954. Specify the date of the issue requested and enclose a check or money order payable to the Superintendent of Documents, or enclose your Visa or Master Card number and expiration date. Credit card orders can also be placed by calling the order desk at (202) 512–1800 (or toll-free at 1–888–293–6498) or by faxing to (202) 512–2250. The cost for each copy is $10. As an alternative, you can view and photocopy the **Federal Register** document at most libraries designated as Federal Depository Libraries and at many other public and academic libraries throughout the country that receive the **Federal Register**.

This **Federal Register** document is also available from the **Federal Register** online database through *GPO Access,* a service of the U.S. Government Printing Office. The Web site address is: *http://www.access.gpo.gov/nara/index.html.*

On November 28, 2003, we issued a proposed rule in the **Federal Register** (68 FR 66920) proposing a prospective payment system for psychiatric hospitals and psychiatric units. The proposed rule would implement section 124 of the Medicare, Medicaid, and SCHIP Balanced Budget Refinement Act of 1999 (BBRA), which requires the implementation of a per diem prospective payment system for inpatient hospital services of psychiatric hospitals and psychiatric units. The proposed prospective payment system would replace the reasonable cost-based payment system currently in effect. We announced that the public comment period for the proposed rule would close at 5 p.m. on January 27, 2004.

The proposed rule, "Medicare Program; Prospective Payment System for Inpatient Psychiatric Facilities," is unique in that it proposes, for the first time, a completely new payment system for the inpatient hospital services of psychiatric hospitals and psychiatric units of acute care hospitals. Due to the complexity and scope of this proposed rule and because many people have requested additional time to examine the proposed rule so that they may provide meaningful comments on its provisions, we have decided to extend the comment period for an additional 30 days. This document announces the extension of the public comment period to February 26, 2004.

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

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

Dated: January 23, 2004.

Dennis G. Smith,

Acting Administrator, Centers for Medicare & Medicaid Services.

Approved: January 26, 2004.

Tommy G. Thompson,

Secretary.

[FR Doc. 04–1945 Filed 1–27–04; 11:10 am]

BILLING CODE 4120–01–P

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

RIN 1018–AI95

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

[Docket No: 021223326–4022–02]

RIN 0648–AQ69

50 CFR Part 402

Joint Counterpart Endangered Species Act Section 7 Consultation Regulations

AGENCIES: Fish and Wildlife Service, Interior; National Marine Fisheries Service, National Oceanic and Atmospheric Administration, Commerce.

ACTION: Proposed rule.

SUMMARY: The U.S. Department of the Interior, Fish and Wildlife Service (FWS) and the U.S. Department of Commerce, National Oceanic and Atmospheric Administration, National Marine Fisheries Service (NOAA Fisheries) (referred to jointly as "Services" and individually as "Service"), after coordination with the Environmental Protection Agency (EPA) and the U.S. Department of Agriculture (USDA), are proposing joint counterpart regulations for consultation under section 7 of the Endangered Species Act of 1973, as amended (ESA) for regulatory actions under the Federal Insecticide, Fungicide and Rodenticide Act (FIFRA). Counterpart regulations, described in general terms in the same part, are intended to provide flexibility in the ways that a federal agency may meet its obligations under the ESA by creating alternative procedures to the existing section 7 consultation process described in the same part. These counterpart regulations would complement the existing section 7 consultation process described in the same part and enhance the efficiency and effectiveness of the section 7 consultation process by increasing interagency cooperation and providing

two optional alternatives for completing section 7 consultation for FIFRA regulatory actions. One alternative process would eliminate the need for EPA to conduct informal consultation and obtain written concurrence from the Service for those FIFRA actions that EPA determines are "not likely to adversely affect" any listed species or critical habitat. The other alternative consultation process would permit the Service to conduct formal consultation in a manner that more effectively takes advantage of EPA's substantial expertise in evaluating ecological effects of FIFRA regulatory actions on federally-protected threatened and endangered species ("listed species") and critical habitats.

DATES: Comments on this proposal must be received by March 30, 2004 to be considered in the final decision on this proposal.

ADDRESSES: Comments or materials concerning the proposed rule should be sent to the Assistant Director for Endangered Species, U.S. Fish and Wildlife Service, 4401 North Fairfax Drive, Room 420, Arlington, Virginia 22203. You may also comment via the Internet to *PesticideESARegulations@fws.gov*. Please submit Internet comments as an ASCII file avoiding the use of special characters and any form of encryption. Please also include "Attn: 1018–AI95" and your name and return address in your Internet message. Comments and materials received in conjunction with this rulemaking will be available for inspection, by appointment, during normal business hours at the above address.

The FWS has agreed to take responsibility for receipt of public comments and will share all comments it receives with NOAA Fisheries, EPA and USDA. All the agencies will work together to compile, analyze, and respond to public comments.

FOR FURTHER INFORMATION CONTACT: Gary Frazer, Assistant Director for Endangered Species, at the above address (Telephone 703/358–2171, Facsimile 703/358–1735) or Phil Williams, Chief, Endangered Species Division, NOAA Fisheries, 1315 East-West Highway, Silver Spring, MD 20910 (301/713–1401; facsimile 301/713–0376).

SUPPLEMENTARY INFORMATION: The FWS and NOAA Fisheries are proposing for public comment a joint rulemaking to amend existing regulations to enhance the efficiency and effectiveness of the consultation process under section 7 of the ESA and to provide alternatives to the way EPA now consults with the Services under the ESA on regulatory actions under FIFRA involving pesticides. This Notice of Proposed Rulemaking (NPR), developed with assistance from EPA and the USDA, would complement the Services' existing consultation regulations in 50 CFR part 402. A rule providing an alternative consultation process for a specific Federal agency is called a "counterpart regulation." *See* 50 CFR 402.04. The purpose of this proposed rule is to improve interagency cooperation for regulatory actions under FIFRA involving pesticides, and provide optional, alternative approaches to consultation on pesticide actions that better integrate the consultation process under section 7 of the ESA with the processes for pesticide regulatory actions taken by EPA under FIFRA. By doing so, the Services expect the administration of the ESA and FIFRA will better protect threatened and endangered species and critical habitat with minimal disruption of the nation's access to products licensed under FIFRA that are necessary for the production of food and fiber and for health and disease protection. Additional supplementary information concerning this proposed rule is available on the Internet at *http://endangered.fws.gov/consultations/pesticides*.

1. The Endangered Species Act and Federal Agency Consultations With the Services

Congress enacted the ESA to establish a program for conservation of endangered and threatened species and the ecosystems on which they depend. 16 U.S.C. 1531(b). Section 7 of the ESA, 16 U.S.C. 1536, imposes obligations upon all Federal agencies whose actions may affect listed species or designated critical habitat. Section 7(a)(2) of the ESA, 16 U.S.C. 1536(a)(2) directs all Federal agencies, in consultation with and with the assistance of the Secretaries of the Interior and Commerce (delegated to the respective Services), to insure that any action authorized, funded, or carried out by such agency is not likely to jeopardize the continued existence of any listed species or result in the destruction or adverse modification of habitat of such species that has been designated as critical ("critical habitat"). 16 U.S.C. 1536(a)(2). In meeting this requirement, each agency is required to use the "best scientific and commercial data available." 16 U.S.C. 1536(a)(2). The FWS and NOAA Fisheries are jointly responsible for administering the ESA.

The Services adopted joint consultation regulations set forth at 50 CFR part 402. These regulatory provisions require action agencies to consult with the Services on any Federal action that "may affect" a listed species or critical habitat. Consultation may be concluded "informally" if the action agency determines that the Federal action under consideration is "not likely to adversely affect" (NLAA) a listed species or critical habitat and the Service gives written concurrence. 50 CFR 402.13(a)(1). Such informal consultation fulfills the action agency's section 7 consultation obligation. 50 CFR 402.14(b)(1). Formal consultation, however, may always be pursued and is required if the action is likely to adversely affect a listed species or critical habitat or if the Service does not concur with an action agency's NLAA determination. During formal consultation, the action agency and Service examine the effects of the proposed action and the Service determines whether the proposed Federal action is likely to jeopardize the continued existence of any listed species or result in the destruction or adverse modification of critical habitat and whether incidental take of listed species is anticipated. 50 CFR 402.14(h), 402.14(i).

Under the current consultation regulations, the consultation process reviews a variety of potential "effects" on listed species and habitat, including direct, indirect, and cumulative effects. "Direct effects" are those effects that will immediately flow from the proposed action. "Indirect effects" are those that will be caused by the proposed action, will occur later in time, but are still reasonably certain to occur. Additionally, examination of potential effects must also address "interrelated" and "interdependent" actions. 50 CFR 402.02. "Cumulative effects" are those effects of future State or private activities, not involving Federal activities, that are reasonably certain to occur within the area affected by the proposed action. 50 CFR 402.02. For a detailed explanation of these terms, refer to the Consultation Handbook jointly published by FWS and NOAA Fisheries, which further elaborates on the procedures followed by the Services when conducting section 7 consultations. *http://endangered.fws.gov/consultations/s7hndbk/s7hndbk.htm*.

At the conclusion of formal consultation, the Service will issue a biological opinion that details the effects of the action on the listed species or critical habitat, and states whether the action is likely to jeopardize the continued existence of a listed species or result in the destruction or adverse modification of critical habitat. 16

U.S.C. 1536(b)(3)(A). If the Service finds an agency action is likely to cause any such effect, the biological opinion must also include reasonable and prudent alternatives, if any are available, that would avoid the effect. Where jeopardy or adverse modification of critical habitat is not likely to occur, but take of listed species is expected, the Service issues an incidental take statement that specifies reasonable and prudent measures and terms and conditions necessary to minimize incidental take. 16 U.S.C. 1536(b)(4). When the terms and conditions of the incidental take statement are followed, all incidental takings that occur are not subject to any prohibition against take that may otherwise apply. 16 U.S.C. 1538(a)(1); 1533(d). Following consultation, the action agency is responsible for implementing protections, if necessary, through its available authority.

Regulations at 50 CFR 402.04 provide that "the consultation procedures may be superseded for a particular Federal agency by joint counterpart regulations among that agency, the Fish and Wildlife Service, and the National Marine Fisheries Service." The Services recognized that in certain instances, the section 7 consultation process can be improved by procedures that differ from the standard consultation process. The purpose of counterpart regulations therefore is to provide an approach that "allow[s] individual Federal agencies to "fine tune" the general consultation framework to reflect their particular program responsibilities and obligations." 51 FR 19937 (June 3, 1986). At the same time, the preamble to the 1986 regulations for implementing section 7 of the ESA states that "such counterpart regulations must retain the overall degree of protection afforded listed species required by the [ESA] and these regulations. Changes in the general consultation process must be designed to enhance its efficiency without elimination of ultimate Federal agency responsibility for compliance with section 7." *Id.* (quoting the preamble justification for the predecessor regulation).

2. FIFRA and Pesticide Regulation

FIFRA is the primary statute under which EPA regulates the use of pesticides in the United States. 7 U.S.C. 136 *et seq.* FIFRA defines a "pesticide" as "* * * any substance or mixture of substances intended for preventing, destroying, repelling, or mitigating any pest. * * *" FIFRA section 2(u). When a pesticide is sold or distributed, it is generally referred to as a "pesticide product." Pesticides contain both "active ingredients" and "inert ingredients." An "active ingredient" is "* * * an ingredient which will prevent, destroy, repel, or mitigate any pest. * * * " FIFRA section 2(a). Ingredients which are not active are referred to as "inert ingredients" or "other ingredients." Under FIFRA, an "inert ingredient" is defined as "an ingredient which is not active." FIFRA section 2(m). EPA uses the term, "formulation," to refer to the particular combination of active and inert ingredients in a pesticide product. A pesticide "use" refers to the particular combination of circumstances under which a pesticide product may be applied, such as the rate, timing, method, and site of application.

The statutory framework for regulation of new pesticide products. FIFRA generally prohibits the sale or distribution of a pesticide product unless it has first been "registered" by EPA. FIFRA section 12(a)(1)(A). EPA issues a license, referred to as a "registration," for each specific pesticide product allowed to be marketed; the registration approves sale of a product with a specific formulation, in a specific type of package, and with specific labeling limiting application to specific uses. Each product is evaluated on a case-by-case basis.

FIFRA requires a person seeking to register a pesticide to demonstrate that the proposed product meets the statutory standard. The proponent of use bears the burden of demonstrating that a pesticide meets this statutory standard. EPA may approve the unconditional registration of a pesticide product only if the agency determines, among other things, that use of the pesticide would not cause "unreasonable adverse effects on the environment." FIFRA section 3(c)(5). The statute defines "unreasonable adverse effects on the environment" to include "any unreasonable risk to man or the environment, taking into account the economic, social, and environmental costs and benefits of the use of any pesticide. * * *" FIFRA section 2(bb). EPA has a broad duty under FIFRA to avoid unreasonable adverse effects on the environment generally, which includes consideration of effects to all species, whether or not federally protected.

When EPA registers a pesticide, it approves among other things a specific set of labeling for the product which contains directions for and restrictions on use of the product. Labeling includes any written or graphic material attached to the product container, *i.e.*, the label, as well as other material accompanying the product or referenced on the label. FIFRA section 2(p). FIFRA makes it unlawful for any person "to use any registered pesticide in a manner inconsistent with its labeling." FIFRA section 12(a)(2)(G). Thus, directions and restrictions appearing on, or referenced in, a pesticide product label become enforceable Federal requirements subject to penalties for misuse. Under FIFRA, most States have primary responsibility for enforcement against pesticide misuse. *See* FIFRA section 26.

While most regulatory decisions allowing entry of new pesticide products into the marketplace are made by EPA in its FIFRA § 3 registration program, there are three other programs that can authorize the limited use of new pesticides. Under section 18 of FIFRA, EPA may allow the use of an unregistered pesticide product by a State or Federal agency when necessary to address an emergency situation. Under EPA's regulations, a petition for an exemption must establish that "emergency conditions"—defined as "an urgent, non-routine situation that requires the use of a pesticide * * *"—exist and that no effective, currently registered pesticide or non-pesticidal pest control method is available. 40 CFR 166.4(d). The emergency exemption regulations provide that EPA will not approve a request unless EPA determines, among other things, the use of the pesticide product will not cause unreasonable adverse effects on the environment. 40 CFR 166.25(b). In addition, under certain limited circumstances, States may approve a new use of a currently registered pesticide product to meet a "special local need." FIFRA section 24(c). EPA's regulations limit States' exercise of this authority only to the approval of products that contain active ingredients that are present in a currently approved pesticide product and give EPA broad authority to disapprove products intended for uses that are not closely related to existing uses. See 40 CFR 162.152. States must notify EPA when they exercise this authority and a State's registration shall not be effective for more than 90 days if disapproved by EPA within that period. FIFRA section 24(c)(2). Finally, EPA may issue an experimental use permit under FIFRA section 5 authorizing the limited use of an unregistered pesticide in field experiments to obtain data necessary to support an application for registration. *See* 40 CFR part 172.

The statutory framework for regulation of existing pesticide products. In addition to a registration program for new pesticide products, EPA conducts a "reregistration" program. Reregistration focuses on currently registered pesticides and involves a systematic reexamination of the scientific data to determine whether the pesticides continue to meet contemporary scientific and regulatory standards. *See* FIFRA section 4. As part of the reregistration process, EPA assesses whether there are adequate data to determine if the statutory standard is met. FIFRA gives EPA authority to require registrants to provide data if EPA "determines [the] additional data are required to maintain in effect an existing registration of a pesticide." FIFRA section 3(c)(2)(B). (Imposition of such additional data requirements is subject to the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501–3520). In the past, EPA has used this authority to require registrants to conduct studies that would provide additional data needed for the evaluation of potential hazards of and exposures to pesticide products. EPA uses such data to assess pesticide risks and to determine whether changes in the terms and conditions of registration would be appropriate. In many cases, EPA's reregistration review has concluded that additional risk mitigation measures were necessary to reduce potential harm to non-target plants and wildlife populations. Many registrants voluntarily have amended their products' registrations to implement these risk mitigation measures. If, however, registrants do not adopt needed risk mitigation, EPA may impose the requirements through cancellation or suspension proceedings, conducted pursuant to FIFRA section 6 and 40 CFR part 164.

EPA may issue a Notice of Intent to Cancel the registration of a pesticide if it appears at any time that the continued use of the pesticide "generally causes unreasonable adverse effects on the environment." FIFRA section 6(b). The registrant of a pesticide is required to submit to EPA additional factual information regarding unreasonable adverse effects. FIFRA section 6(a)(2); 40 CFR part 159. The decisions whether to approve a pesticide's entry into the marketplace and whether to retain a pesticide on the market are based on the most recent scientific information and the same standard: whether use of pesticide does not cause "unreasonable adverse effects on the environment." FIFRA also contains provisions allowing EPA to "suspend" the registration and use of a pesticide, prior to the completion of a cancellation process, if use of the pesticide poses an "imminent hazard." FIFRA section 6(c). FIFRA defines an "imminent hazard" as "a situation which exists when the continued use of a pesticide during the time required for [a] cancellation proceeding would be likely to result in unreasonable adverse effects on the environment or will involve unreasonable hazard to the survival of a species declared endangered or threatened under [the Endangered Species Act]." FIFRA section 2(l).

EPA's approach to ecological risk assessment. In deciding whether a pesticide product meets the statutory standards for registration or reregistration, EPA considers, among other things, the potential risks to non-target wildlife and plant species posed by use of the pesticide product. A more detailed description of EPA's approach appears in a paper titled: "Overview of the Ecological Risk Assessment Process in the Office of Pesticide Programs, U.S. Environmental Protection Agency" ("Overview Paper") (January 2004), and in documents referenced in that paper, all of which are part of the administrative record of this NPR. This document describes EPA's risk evaluation process which is based on the current science policy views of EPA's pesticide program, but it is not intended to be legally binding. In any decision under FIFRA, EPA may: (1) conclude that the general approach to assessing ecological risks of a particular pesticide is inapplicable; or (2) consider factors or types of information other than those described in the Overview Paper. If EPA uses a different approach to make an effects determination for a FIFRA action, EPA would provide a detailed explanation of its approach in the record for the action.

EPA's evaluation of such environmental risks follows the principles contained in its Guidelines for Ecological Risk Assessment. (EPA 1998). In 1986, EPA developed detailed guidance for the review and analysis of potential environmental risks from use of pesticide products. See Standard Evaluation Procedures (SEP) for Ecological Risk Assessment (EPA 1986). Since 1986 EPA has made many additions and refinements to the basic approach outlined in the SEP. All of EPA's risk assessment methods have included methodology for an assessment of potential risks to listed species.

EPA's approach to assessing risks of pesticides and framework for making regulatory decisions benefits from the advice of several advisory committees chartered under the Federal Advisory Committee Act (FACA). EPA routinely obtains independent, external, expert scientific peer review of its risk assessment methodologies from the FIFRA Scientific Advisory Panel (SAP). Authorized under FIFRA section 25(d), the SAP is chartered under FACA and consists of seven permanent members appointed by the EPA Administrator and additional ad hoc members who are selected to serve on panels addressing specific scientific issues to which they can contribute their expertise. The SAP provides EPA with recommendations and evaluations of data, models, and methodologies used in EPA's overall risk assessment processes that occur during registration and reregistration. Further information is available at: *http://www.epa.gov/scipoly/sap/*.

EPA also works with stakeholders in the regulated community and environmental and public health advocacy groups through two other FACA-chartered groups: the Pesticide Program Dialogue Committee (PPDC) and the Committee to Advise on Reassessment and Transition (CARAT). For further information see: *http://www.epa.gov/pesticides/ppdc/* and *http://www.epa.gov/pesticides/carat/*. These latter two advisory groups often address ways in which to make regulatory processes more reliable and efficient. All three advisory groups comply with the FACA requirements for transparency and balanced participation.

EPA requires both new and existing pesticides to be supported by extensive information about the potential ecological risks of the pesticide product. Data requirements appear in EPA regulations at 40 CFR part 158. Laboratory studies conducted to generate data for EPA are subject to Good Laboratory Practice requirements that are designed to ensure that the results are reliable and of high quality. *See* 40 CFR part 160. EPA's scientists carefully review all data submissions and independently evaluate the potential risks of each pesticide. In situations raising novel or challenging scientific issues, EPA generally seeks outside peer review of its scientific assessments.

EPA requires extensive toxicity and environmental fate data and uses this information, together with field reports of adverse effects on wildlife caused by pesticides and other relevant information, to evaluate the potential hazards to non-target species, including listed species, of a pesticide intended for outdoor use. To assess potential hazard to non-target species, EPA requires a basic set of laboratory toxicity studies on an active ingredient using multiple surrogate species of birds, fish, aquatic invertebrates, non-target insects, and plants. In situations where additional, scientifically valid toxicity data related to effects on wildlife and aquatic organisms are available, EPA will consider them in establishing the toxicity endpoint for risk assessment. EPA conducts risk assessments using the toxicity endpoint from the most sensitive species tested. EPA also requires data from a series of laboratory and field studies of the environmental fate of both the active ingredients in a pesticide product and typical formulations containing the active ingredient. These studies provide data on both the parent active ingredient, as well as its environmental degradates.

EPA combines these data, along with information about how the pesticide product is intended to be used, to develop an estimate of the potential concentrations of residues of the active ingredient and significant environmental degradates in the environment (the Estimated Environmental Concentration or EEC). When estimating EEC, EPA makes conservative assumptions designed not to understate potential exposure in order to avoid the potential for underestimating risk.

When assessing risks to listed species and critical habitat, EPA evaluates data and risks in a tiered fashion. EPA compares its toxicity assessment of an active ingredient with the EEC. As part of a conservative initial risk screening, if this comparison demonstrates that the EEC is well below the amount of active ingredient that would be expected to cause harm to particular species or critical habitats, EPA concludes that the use of pesticide products containing that active ingredient would have "no effect" on those listed species or critical habitats. Most of EPA's focus is on the potential risks from exposure to the active ingredient and its significant environmental degradates. EPA also reviews the available information on the other ingredients in pesticide products and on the formulations themselves, to assess the potential for increased risk. If the conservative initial screening assessment indicates that a use of a pesticide may potentially affect a listed species or critical habitat, EPA conducts a more refined assessment looking at species-specific information and information about pesticide use in the area to determine whether, for example, there is spatial and temporal overlap of the pesticide use and species' habitat, such that adverse effects would appear likely.

If the initial comparison and subsequent refined assessments indicate that EPA's best estimate of the EEC for the active ingredient and/or significant environmental degradates could have toxic effects on a listed species or critical habitat, then EPA may require the pesticide applicant or registrant to supply additional laboratory and/or field data in order to refine the risk assessment, seek changes in the allowable use of the pesticide product that are sufficient to mitigate any potential risk, or request initiation of consultation with the Services. Higher tier toxicity data may include studies on the effects of a pesticide on other wildlife species and plants or studies of longer durations of exposure. The Agency may occasionally require higher tier studies to be conducted in the field under simulated or actual use conditions. EPA may also require additional information to improve its estimate of potential exposure. Possible risk mitigation measures include changes in the manner or timing of pesticide applications, the rate or frequency of applications, or geographical restrictions on use.

Between May and December 2003 inter-agency scientific teams from both Services and EPA carefully reviewed EPA's ecological risk assessment methodology, including earlier drafts of the Overview Paper and the materials referenced therein. Based on this review, the Services have determined that the approach used by EPA designated will produce effects determinations that reliably assess the effects of pesticides on listed species and critical habitat pursuant to section 7 of the ESA and implementing regulations. The approach used by EPA addresses, where applicable, the informational and analytical requirements set forth at 50 CFR 402.14(c), relies upon the best scientific and commercial data available; and analyzes the best scientific and commercial data available by using sound, scientifically accepted practices for evaluating ecological effects. Additionally, the Services have concluded that the approach used by EPA should produce effects determinations that appropriately identify actions that are not likely to adversely effect listed species, and that are consistent with those that otherwise would be made by the Services. This approach also will produce all information necessary to initiate formal consultation where appropriate. Letter from S. Williams and W. Hogarth to Susan Hazen (January 2004).

3. Public Law 100–478

In 1988, Congress addressed the relationship between ESA and EPA's pesticide labeling program in section 1010 of Public Law 100–478 (October 7, 1988), which required EPA to conduct a study, and to provide Congress with a report of the results, on ways to implement EPA's endangered species pesticide labeling program in a manner that both complies with ESA and allows people to continue production of agricultural food and fiber commodities. This law provided a clear sense that Congress desires that EPA should fulfill its obligation to conserve listed species, while at the same time considering the needs of agriculture and other pesticide users. Accordingly, EPA and the Services have coordinated with USDA in developing these counterpart regulations to ensure that the consultation process is efficient and timely while remaining as protective as the existing regulations.

4. The Joint Advance Notice of Proposed Rulemaking on Pesticides and Endangered Species

On January 24, 2003 the Services and EPA published an Advance Notice of Proposed Rulemaking (ANPR) inviting public comment on a variety of ideas for improving the process by which EPA and the Service work together to protect listed species and critical habitat. 68 FR 3785. The ANPR sought public comment on possible approaches to changing the current regulations, policies, and practices of the EPA and Service to better integrate the FIFRA and ESA processes and to improve the efficiency and effectiveness of consultations on pesticide actions. The agencies specifically identified several broad approaches to changing the current process. For example, the ANPR asked for comment on whether it would be possible for EPA to satisfy some or all of its ESA section 7(a)(2) consultation obligations for individual registration actions by completing what could be described as programmatic consultations affecting numerous registration and reregistration actions that share key common characteristics. Under existing Service regulations at 50 CFR part 402, the Service and Federal agencies can engage in consultations that address major national programs. There is potential to use this authority to develop a "programmatic" approach to consultation on the pesticide registration program. In addition, even where such programmatic consultations would not be sufficient to complete the consultation process for certain individual actions, the Notice asked for comment on whether they could serve to improve the consultation process on such actions through the standardization of risk assessment methodologies and alternatives for species protections.

The ANPR also requested comment on an approach that would streamline the informal consultation process. For this approach, which is reflected in the counterpart regulation being proposed today, the ANPR asked for comment on whether there is a need for either further consultation or Service concurrence in those situations where EPA determines that use of a pesticide is "not likely to adversely affect" listed species or critical habitat.

The agencies also sought comment on an approach that would focus the review by the Service during consultation. This approach was predicated on the assumption that EPA's practices and policies would be reviewed and, where necessary, revised to ensure that the data and analyses EPA obtains and uses provide the best available information on the effects on listed species. As discussed earlier, EPA has extensive information available with which to assess and mitigate potential risks to listed species and their critical habitat, and EPA has developed considerable expertise in these areas. In view of this expertise, the ANPR therefore asked for comment on whether the Service should rely on EPA's assessment of effects once formal or informal consultation had been initiated on a pesticide regulatory action.

The ANPR also asked for comments on possible changes to the existing framework, while retaining the basic approach of requiring consultation whenever EPA determines that use of a pesticide "may affect" protected species. The ANPR covered the following topics:

- Modifying EPA's approach to assessing potential risk to listed species
- Introducing flexibility in the scope of consultations
- The content of consultation packages and definition of the term "best scientific and commercial data available"
- Establishing timelines for conducting informal and formal consultations on pesticide regulatory actions
- Establishing procedures for consultations on emergency actions under FIFRA
- Clarifying the role of the Service
- Establishing procedures for public participation and clarifying the meaning of the term, "applicant," in the context of consultations between EPA and the Services on pesticide regulatory actions
- Clarifying and improving the roles of States, Tribes, and other entities that might potentially act as non-Federal representatives in consultations between EPA and the Services on pesticide regulatory actions
- Fees
- Process for elevating and resolving disagreements between EPA and the Service

In response to the ANPR, the Services received comments from over 300 groups, organizations, and individuals, about half of which were letters and post cards from different individuals making the same comment. Comments came from a wide range of stakeholder organizations and individuals and presented a diverse array of opinions about what actions the government should take to promote and ensure EPA compliance with the ESA for actions under FIFRA. While most commenters expressed support for the goals of the ESA and many recognized the need to implement the ESA in a manner that was efficient and compatible with FIFRA, there were strongly differing perspectives about what course would best achieve those goals.

In general, environmental advocacy groups raised a number of criticisms about EPA's approach to assessing the risks of pesticides and regulating their use, and argued that historically EPA has had a poor record of compliance with the consultation obligations of the ESA with regard to pesticides. These commenters therefore favored a strong role for the Services and opposed any changes to the existing consultation regulations. In particular, they argued that a rule which either allowed EPA to make NLAA determinations, without consulting with and obtaining the concurrence of the Service, or afforded deference to EPA's assessments, would be contrary to the ESA. Moreover, such a rule would contain insufficient safeguards to assure proper application of the ESA and could be subject to abuse by EPA.

Agricultural pesticide user groups and pesticide manufacturers and trade associations generally stressed the extensive expertise EPA possesses in the assessment of pesticides' ecological risks and the benefits of a more efficient and consistent process. They also argued that the existing consultation regulations were designed primarily for agency actions that involved construction projects or other actions with a relatively limited geographic scope and therefore were inappropriate for the types of regulatory actions taken by EPA under FIFRA. They also questioned whether the Services had the resources and expertise to review FIFRA actions and pointed out that the time required to conduct consultations would delay decisions about the use of socially beneficial pesticides. These commenters therefore expressed support for new consultation procedures that would give EPA greater flexibility to reach conclusions under the ESA about the impact of FIFRA actions on listed species and critical habitat, with reduced or no involvement by the Services.

The Services and EPA have considered all of the comments, and the Services conclude that the goals of the ESA can be fully met using new, more efficient administrative processes that take advantage of EPA's expertise while retaining a strong role for the Services throughout the consultation process to assure that the requirements of the ESA are met. Accordingly, the Services are now proposing a counterpart regulation for consultation on FIFRA actions.

5. Reasons for a Counterpart Regulation for EPA Pesticide Actions

Rationale for the rule as proposed. In developing a process for conducting future ESA consultations on FIFRA pesticide regulatory actions, the Services and EPA recognized that EPA possesses significant resources, expertise and authority in the field of ecological risk assessment relative to pesticides. Under FIFRA, EPA makes decisions to allow new or continued use of a pesticide only after carefully examining extensive data on the potential risks that use of a pesticide may pose to non-target wildlife species. In addition, EPA's pesticide regulatory program may require companies to conduct studies needed for a risk assessment. As a result, EPA generally has a significant body of scientific information available with which to evaluate the hazards a pesticide may pose to non-target wildlife. Further, to perform its responsibilities under FIFRA, EPA maintains a staff of well-qualified scientists with many years of combined experience in assessing ecological risks. Finally, EPA has performed pioneering work in certain areas of ecological risk assessment, such as the development of exposure models and probabilistic risk assessment techniques.

In addition to EPA's strong scientific data bases and its expertise in the field of ecological risk assessment, EPA's decisions have characteristics that are rarely found in other section 7 consultations. Pesticide products typically are employed for multiple uses, and can potentially be used in many different parts of the country in different times of year. Thus, an ESA consultation on a pesticide registration must consider many different pesticide use patterns and determine whether wildlife or plant species in many different locations throughout the country may be affected by such use. This broad scope of intended use of the product under review contrasts with the narrower geographical scope of most actions by Federal agencies that undergo section 7 consultation.

In addition, the number of annual pesticide decisions made by EPA is also a factor potentially affecting how best to improve the section 7 consultation process. In a typical year, EPA will make hundreds of significant decisions regarding pesticide registration. For example, in fiscal year (FY) 2003, EPA registered 31 new pesticide active ingredients; approved the addition of 334 new uses of previously registered active ingredients on over 1,500 different crops; and completed more than 6,500 more minor registration actions. EPA also completed re-registration assessments on 28 previously registered active ingredients, and processed nearly 500 emergency exemption requests in FY 2003. Numbers of actions in most of these categories have risen each year since FY 2000. The number of requests by EPA to initiate consultation on pesticide actions is expected to increase substantially in future years. The large number of consultations and their complexity is expected to require a significant level of resources, requiring careful use of resources by both EPA and the Services to effectively address issues of high biological priority and high priority to users in the most efficient manner possible. This rule, if finalized, may make the consultation process more efficient because some FIFRA actions could be conducted pursuant to the alternative consultation procedures outlined in this rule.

These factors provide strong reasons for the Services to propose establishing a counterpart rule for EPA FIFRA actions. New, streamlined procedures promise to be more efficient for both EPA and the Services, and potentially more protective of listed species, because they would allow EPA and the Services to focus more resources on those actions most likely to pose risk to listed species. The single greatest opportunity for efficiency in the consultation process is for the Services to take greater advantage of the extensive analysis produced by EPA in its ecological risk assessments of pesticides. Relying more heavily on the EPA's scientific work product, while at the same time assuring EPA's analysis meets the high scientific standards required by the ESA, will reduce the amount of work required from the Services in each consultation and therefore accelerate completion of consultations.

Further, those streamlined procedures are expected to enable EPA to more quickly implement any risk mitigation measures identified as necessary to protect species and critical habitat. Moreover, many of the applications submitted for registration of pesticide products containing new active ingredients involve pesticide formulations that have been developed to have less impact than the currently registered products with which they would compete. Thus, any improvements in the efficiency and effectiveness of the ESA review process to put these new products in the market sooner could benefit listed species, as well as more broadly provide benefits for human health and the environment. Finally, given the importance of maintaining the availability of pesticides for production of food and fiber, disease prevention and other purposes that are essential to the health and well-being of the American people, EPA and the Services believe that improved integration of the FIFRA registration/reregistration and section 7(a)(2) consultation processes under new counterpart regulations can be achieved in a way that avoids unnecessary burdens on pesticide users with no sacrifice to the protection of listed species.

6. The Proposed Counterpart Rule

The proposed counterpart regulations would establish new methods of interagency coordination between EPA and the Services and create two new, optional, alternative approaches for EPA to fulfill its obligations to ensure that its actions under FIFRA are not likely to jeopardize the continued existence of listed species or destroy or adversely modify critical habitat. The proposed rule offers a new alternative approach when EPA determines that a FIFRA action is not likely to cause adverse effects on listed species or critical habitat, and a new alternative approach to formal consultations. EPA could also elect to follow any of the existing procedures for early (§ 402.11), informal (§ 402.13), or formal consultation (§ 402.14) described in subpart B of part 402 for these actions.

A. New Methods of Interagency Cooperation

The proposed counterpart rule would establish three additional methods (§§ 402.42(b), 402.43 and 402.44) of achieving the interagency cooperation that is the fundamental tenet of the section 7 consultation process. First, under § 402.43 EPA could request the Service to provide available information (or references thereto) describing the applicable environmental baseline for each species or habitat that EPA determines may be affected by a FIFRA action, and the Service would provide such information within 30 days of the request. This informational exchange would give EPA early and effective access to the Service's extensive biological database.

Second, under § 402.44 EPA may request the Service to designate a suitably-trained Service Representative (more than one Service employee may jointly serve in this capacity) to participate with EPA in the development of an "effects determination" for one or more of those species or habitats. The Service Representative will participate in all relevant discussions with the EPA team (in most cases in person), have access to all documentation and information used to prepare the effects determination (upon acceptance of the same confidentiality limitations applicable to EPA personnel), and have appropriate office and staff support to work effectively as part of the EPA team. The Service Representative will be expected to keep the Service informed at all times as to the progress and scope of the effects determination, and the Service may engage in additional coordination with EPA as appropriate. In some cases, EPA may decide that it does not require the aid of a designated Service Representative, and may make an effects determination without that form of coordination.

Third, under § 402.42(b), EPA and the Services would establish new procedures for regular and timely exchanges of scientific information to achieve accurate and informed decision-making.

B. Consultation on Actions That Are Not Likely To Adversely Affect Species or Habitats

The existing section 7 regulations require an action agency to complete formal consultation with the Service on any proposed action that may affect a listed species or critical habitat, unless following either a biological assessment or informal consultation with the Service, the action agency makes a determination that the proposed action is not likely to adversely affect any listed species or critical habitat and obtains written concurrence from the Service for the NLAA determination. The alternative consultation process contained in section 402.45 of the proposed counterpart regulation will allow the Service to provide training, oversight, and monitoring to EPA through an alternative consultation agreement that enables EPA to make an NLAA determination for a FIFRA action without formal or informal consultation or written concurrence from the Service. The Services recently adopted a similar approach for certain Federal actions implementing the National Fire Plan. 68 FR 68254 (December 8, 2003).

The new approach to interagency coordination between EPA and the Services is intended to be a flexible, adaptable scheme that will continually evolve and improve over time as scientific knowledge expands. For this reason, although the proposed regulation would require the Service and EPA to have in effect an alternative consultation agreement before EPA can utilize the procedures of section 402.45, the alternative consultation agreement itself is not part of this rule, and the Services have concluded that the alternative consultation agreement would not constitute a rule subject to the notice and comment provisions of the Administrative Procedure Act, 5 U.S.C. 553. As articulated in proposed section 402.45(b), the required content of the alternative consultation agreement include provisions and procedures to guide the Services and EPA in implementing this subsection. The alternative consultation agreement does not create or mandate standards for effects determinations; nor does it limit EPA's or the Service's discretion in developing and applying scientific methodologies. The alternative consultation agreement would be expected to undergo continuous modification and improvement. EPA and the Service would also be able to mutually agree to depart from the terms of the alternative consultation agreement in a particular case. Further, the alternative consultation agreement would not create any substantive or procedural rights or benefits that could be enforced by third parties against either the Services or EPA.

The Services believe that EPA's expertise in ecological risk assessments of pesticides, together with the safeguards built into the alternative consultation agreement, make case-by-case discussions and written concurrences in EPA's NLAA determinations unnecessary for FIFRA actions. The Services have carefully reviewed EPA's assessment methodologies and believe that when EPA follows its established approach to ecological risk assessment for pesticides EPA will correctly make determinations as to when a pesticide is or is not likely to adversely affect listed species or critical habitat. Requiring the Services to concur on a case by case basis on every NLAA determination made by EPA would unjustifiably divert much of the Services' consultation resources away from projects in greater need of consultation. The proposed counterpart regulations will increase the Services' capability to focus on Federal actions requiring formal consultation by eliminating the requirement to provide written concurrence for actions within the scope of the proposed counterpart regulations. EPA and the Services are committed to implementing this authority in a manner that will be equally as protective of listed species and critical habitat as the current procedures that require written concurrence from the Service.

These proposed counterpart regulations provide an additional tool for accelerating EPA's ESA compliance activities, while providing equal or greater protection of listed species and critical habitat. Under current procedures, EPA already must complete and document a full ESA analysis to reach an NLAA determination. The proposed counterpart regulations permit a FIFRA action to proceed following EPA's NLAA determination without an overlapping review by the Service, where the Service has provided specific training and oversight to achieve comparability between EPA's determination and the outcome of an overlapping review by the Service.

The approach proposed in these counterpart regulations is consistent with Subpart B because it leaves the standards for making jeopardy and NLAA determinations unchanged. Further, when EPA operates under these proposed counterpart regulations it will retain full responsibility for compliance with section 7 of the ESA.

Under the proposed rule, EPA would enter into an alternative consultation agreement with either FWS, NOAA Fisheries or both. The alternative consultation agreement will include: (1) A description of the actions that EPA and the Service have taken to document the approach EPA uses to make determinations regarding the effects of its actions on listed species or critical habitat and to evaluate that approach for consistency with the ESA and applicable implementing regulations; (2) a description of the program for developing and maintaining the skills necessary within EPA to make NLAA determinations, including a jointly developed training program based on the needs of EPA; (3) provisions for incorporating new information and newly listed species or critical habitat into EPA's effects analysis on FIFRA actions; (4) processes that EPA and the Service will use to incorporate scientific advances into EPA's effects determinations; (5) a description of a mutually agreed upon program for periodic program evaluations; and (6) provisions for EPA to maintain a list of FIFRA actions for which EPA has made NLAA determinations. By following the procedures in these counterpart regulations, including the establishment of the alternative consultation agreement, EPA would fulfill its ESA section 7 consultation responsibility for actions covered under these proposed regulations.

The purpose of the jointly developed training program between EPA and the Service is to ensure that EPA consistently interprets and applies the provisions of the ESA and the regulations (50 CFR part 402) relevant to these counterpart regulations with the expectation that EPA will reach the same conclusions as the Service. It is expected that the training program will rely upon the ESA Consultation Handbook as much as possible.

The Service will use monitoring and periodic program reviews to evaluate EPA's performance under the alternative consultation agreement at the end of the first year of implementation and then at intervals specified in the alternative consultation agreement. The Service will evaluate whether the implementation of this regulation by EPA continues to be consistent with the best scientific and commercial data available and the ESA. The result of the periodic program review may be to recommend changes to EPA's implementation of the alternative consultation agreement. The Service will retain discretion for terminating the alternative consultation agreement if the requirements under the counterpart regulations are not met. However, any such suspension, exclusion, or termination will not affect the legal validity of determinations made prior to the suspension, exclusion, or termination.

Upon completion of an alternative consultation agreement, EPA and the Service will implement the training program outlined in the alternative consultation agreement. EPA will have full responsibility for the adequacy of its NLAA determinations since there would be no reviewable final agency action by the Service when EPA makes a NLAA determination for a FIFRA action.

The Services and EPA have developed a draft of an alternative consultation agreement that addresses the topics identified in proposed § 402.45. This draft alternative consultation agreement is part of the administrative record of this proposed rule. The public is encouraged to read the draft alternative consultation agreement to obtain a better understanding of how the Services anticipate the requirements of § 402.45 would be satisfied. Such an understanding may be useful in preparing comments on the proposed rule.

C. New Optional Formal Consultation Process

The proposed counterpart regulation establishes a new formal consultation process (§ 402.46) that would meet all statutory requirements and closely follows the procedural steps specified in the current subpart B process. The new process would combine the central concepts and procedures of the subpart B consultation process with innovations stemming from EPA's expertise in assessing the ecological effects of pesticide products.

The process relies on an effects determination that would be prepared by EPA according to analytical methodologies that the Services have reviewed and endorsed. The effects determination may be prepared, upon EPA's request, with the assistance of a Service Representative. While the contents of an effects determination would depend on the nature of the action, an effects determination submitted under § 402.46 or § 402.47 would contain the information described in § 402.14(c)(1)–(6) and a summary of the information on which the determination is based, detailing how the FIFRA action affects the listed species or critical habitat. EPA could also include three additional sections in an effects determination: (1) A conclusion whether or not the FIFRA action is likely to jeopardize the continued existence of any listed species or result in the destruction or adverse modification of critical habitat and a description of any reasonable and prudent alternatives that may be available; (2) a description of the impact of any anticipated incidental taking of such listed species resulting from the FIFRA action, reasonable and prudent measures considered necessary or appropriate to minimize such impact, and terms and conditions necessary to implement such measures; and (3) a summary of any information or recommendations from an applicant. An effects determination with the required information and the additional discretionary sections would contain the information currently provided by the Service in a biological opinion. All effects determinations would be based on the best scientific and commercial data available.

Once EPA has prepared an effects determination for the species and habitats that may be affected, it may initiate formal consultation on a FIFRA action under this section by delivering to the Service a written request for consultation. The written request would be accompanied by an effects determination prepared under § 402.40(b) and a list or summary of all references and data relied upon in the determination. The Service will be able on request to review any or all of the references and data relied upon in the determination as if it was in the Service's files. The time for conclusion of the consultation under section 7(b)(1) of the Act would run from the date the Service receives the written request from EPA. Any subsequent interchanges between the Service and EPA regarding the information submitted by EPA, including interchanges about the completeness of EPA's effects determination, would occur during consultation, and would not delay the initiation of consultation or extend the time for conclusion of the consultation unless EPA withdraws the request for consultation.

If EPA has prepared the effects determination without a designated Service Representative, the Service retains the discretion to determine within 45 days that additional available information would provide a better information base for the effects determination and may so notify EPA. After such a notification, EPA may revise the effects determination and resubmit it to the Service. The timing and form of EPA's resubmission are within its discretion, but the time limitations in section 7(b)(1) continue to apply. A request for additional information does not represent a finding by the Service that the effects determination was not based on the best scientific and commercial data available. Further, any requested additional information must actually be available to EPA during the specified consultation period. Where a designated Service Representative has participated in the development of the effects determination, the Service will rely upon its representative to identify all desired available information during the preparation of the determination, and this intermediate Service review during consultation is not needed. However, EPA at all times retains its duty to use the best scientific and commercial data available for its effects determinations, and the Services retain their duty to use the best scientific and commercial data available during consultation. Once an effects determination has been resubmitted following an additional information determination, the Service will proceed to conclude the consultation without further requests to EPA for additional information, although the Service may consider additional information at any time during the consultation process. If EPA advises the Service it will not resubmit a revised effects determination to the Service after the Service requests additional information, its initiation of consultation on the effects determination would be deemed withdrawn.

Within the later of 90 days after the Service receives EPA's written request for consultation or 45 days after the Service receives an effects determination resubmitted following an additional information determination by the Service, the Service will take one of three actions: (1) If the Service finds that the effects determination contains all required information and satisfies the requirements of section 7(b)(4) of the Act, and the Service concludes that the FIFRA action that is the subject of the consultation complies with section 7(a)(2) of the Act, the Service would issue a written statement adopting the effects determination; or (2) it may provide EPA a draft written statement modifying the effects determination and as modified adopting the effects determination; or (3) it may provide EPA a draft jeopardy biological opinion along with any reasonable and prudent alternatives if available. Providing these draft documents to EPA is consistent with current agency practice under existing consultation procedures. The deadlines for Service action are subject to section 7(b)(1) of the Act.

If the Service provides either the draft statement modifying the effects determination or draft jeopardy opinion, EPA would be required to make it available to any applicant upon request. The proposed rule would also accommodate EPA's existing discretion to make these draft documents available to the general public for comment within the time periods provided in the draft rule. The Service would on request meet with EPA and any applicant, each of which may submit written comments to the Service on the draft document within 30 days or a longer period if extended under section 7(b)(1) of the Act. The Service will issue a final biological opinion or final written statement within 45 days after EPA receives the draft opinion or statement from the Service unless the deadline is extended under section 7(b)(1) of the Act. Any such final opinion or statement will be signed by the Service Director, who may not delegate this authority beyond certain designated headquarters officials, and would constitute the opinion of the Secretary and the incidental take statement, reasonable and prudent measures, and terms and conditions under section 7(b) of the Act.

Where consultation on a FIFRA action will be unusually complex due to factors such as the geographic area or number of species that may be affected by the action, a special provision (§ 402.47) allows EPA, after conferring with the Service, to address the effects of the action through successive effects determinations addressing groupings or categories of species or habitats as established by EPA. This provision is needed because for some widely-used pesticides, delaying the initiation of consultation until adequate information is available for every species or habitat that may be affected by the pesticide may result in denying some of the most vulnerable species the benefits of the section 7 consultation process for as much as several years. Further, allowing geographic or other functional groupings of species lets EPA and the Service conduct related biological inquiries together in an efficient, coordinated manner. EPA would use this provision after conferring with the Services, and EPA and the Services intend to collaboratively identify priorities where use of this provision would most effectively address these biological goals. When successive effects determinations are prepared, EPA may initiate consultation based upon each such effects determination using the procedures in § 402.46(a). The procedure in § 402.46(b) and (c) would apply to the consultation. The written statement or opinion provided by the Service under § 402.46(c) would constitute a partial biological opinion as to the species or habitats that are the subject of the consultation. The partial biological opinion would describe the provisions relating to incidental take of such species for inclusion in an incidental take statement at the conclusion of consultation, giving users of pesticide products such as farmers and forest managers, nursery operators, and other pesticide users prompt and reliable guidance for minimizing incidental take of the species. EPA would also retain authority to use such a partial biological opinion, along with other available information, in making a finding under section 7(d) of the Act as to whether the FIFRA action constitutes an irreversible and irretrievable commitment of resources which has the effect of foreclosing the formulation or implementation of any reasonable and prudent alternative as to those species and habitats. After conclusion of all consultation on the FIFRA action, the previously-issued partial biological opinions would then collectively constitute the opinion of the Secretary and the incidental take statement, reasonable and prudent measures, and terms and conditions under section 7(b) of the Act unless a partial biological opinion were to be modified by the Service using the procedures in § 402.46(c). For pesticide products currently in use, this process would provide prompt guidance for substantial protection for vulnerable species without unduly disrupting longstanding patterns of pesticide use in agriculture, public health vector control or other important pesticide use patterns throughout the country that are vital to the health and welfare of the American people.

The Services emphasize that § 402.47 is not intended as an authorization for EPA to take actions, such as registration of pesticides containing new active ingredients or registration of new uses, without complying with the requirements of section 7(a)(2) of the Act. The provision would not reduce EPA's consultation duties compared to Subpart B. Rather, for certain complex FIFRA actions the provision would strengthen EPA's and the Services' ability to establish the most effective sequence for completing EPA's consultation obligations through a series of focused consultations on specific species or habitats. EPA would not satisfy its procedural obligations under section 7(a)(2) of the ESA until all necessary consultations are completed. Likewise, the Services' issuance of a partial biological opinion following each such focused consultation would not represent the opinion of the Secretary or an incidental take statement under section 7(b) of the ESA until consultation is concluded on all listed species and habitats that may be affected by the action.

The Services expect this provision may be used for FIFRA actions in a variety of circumstances. For example, after reviewing an action, EPA might identify differing levels of risk for different species, and might conclude that it would be prudent to seek Service advice on the impacts of concern through formal consultation while EPA continued to analyze the lesser risk concerns. In addition, if EPA needs to update completed consultations on pesticides by addressing impacts on more than one newly listed species, EPA might find it more efficient and effective to consider each species separately, even though a particular pesticide might impact more than one of the newly listed species. Nonetheless, EPA has advised the Services that EPA does not intend to register any new use or active ingredient until completion of consultation under section 7(a)(2) for all species affected by that action. However, like any action agency, EPA retains statutory authority to use appropriate information to make section 7(d) determinations under the ESA. In sum, the Services believe that it is advisable for the consultation process on these and other complex FIFRA actions to have flexibility, so that EPA and the Services can most efficiently and effectively protect listed species and habitats. EPA would only use the provision after conferring with the Service, which should further insure the continued effective and appropriate use of this authority.

The proposed counterpart rule would make clear that the emergency consultation provisions in existing Service regulations are available to EPA for consultation on actions under FIFRA section 18 by providing that EPA could conduct consultation on actions involving requests for emergency exemptions under FIFRA section 18 under section 402.05 or another available consultation procedure. As provided in § 402.05, any required formal consultation on such an action would have to be initiated as soon as practicable after the emergency is under control. For the purposes of the consultation required in § 402.05(b), the definition of formal consultation in § 402.02 would include the procedures in § 402.46 in addition to those in Subpart B.

The Services believe that EPA's statutory and regulatory standard for an "emergency" under FIFRA section 18 is generally comparable to the intended scope of emergency in § 402.05 and that, therefore, the overwhelming majority of FIFRA emergency exemption actions could properly be considered emergencies for the purposes of § 402.05. Under EPA regulations, FIFRA section 18 emergency exemptions can only be issued for urgent, non-routine situations where a pesticide is needed to address, for example, significant risks to human health or the environment or significant economic loss. 40 CFR 166.1(a), 166.3(d). Pest problems of these dimensions would generally be encompassed within the provisions of § 402.05(a).

The Services' 1998 Joint Consultation Handbook (page 8–1) contains a passage suggesting that emergency actions under FIFRA may not usually qualify as emergencies "unless there is a significant unexpected human health risk." While a significant unexpected human health risk would permit an emergency consultation under § 402.05, the quoted passage should not be read to mean that the emergency provisions in § 402.05 are available for FIFRA section 18 actions only where an unexpected human health risk is present. Such a narrow reading of the quoted passage is inconsistent with other statements in the Handbook and with past Service practice in comparable circumstances. The plain language of § 402.05 is not so limited, and can be read to encompass the kind of emergency situations that FIFRA section 18 contemplates even if no significant unexpected human health risk is present. The Services believe the use of § 402.05 by EPA for FIFRA section 18 actions under the proposed rule would therefore be consistent with practices currently permitted under Subpart B.

The proposed counterpart rule contains other provisions to ensure full compliance with ESA requirements. After a consultation under this Subpart has been concluded, EPA shall reinitiate consultation as required by section 402.16 as soon as practicable after a circumstance requiring reinitiation occurs, and may employ the procedures in this Subpart or Subpart B in any reinitiated consultation. EPA must comply with section 402.15 for all FIFRA actions subject to consultation under this Subpart. EPA must prepare a biological assessment for FIFRA actions that constitute "major construction activities" to the extent required by section 402.12. The typical regulatory actions EPA takes under FIFRA (*e.g.*, registration, reregistration, section 18 approvals) do not, however, generally constitute "major construction activities," and the Services are not aware of any current FIFRA activities that would meet this definition. The proposed rule allows EPA to employ the conferencing procedures described in section 402.10 for any species proposed for listing or any habitat proposed for designation as critical habitat, and provides that for the purposes of section 402.10(d), the procedures in section 402.46 would be a permissible form of formal consultation.

Public Comments Solicited

We intend that any final action resulting from this proposal be as accurate and effective as possible. We are soliciting comments or suggestions from the public, other concerned governmental agencies, the scientific community, industry, or any other interested party concerning this proposed rule. Prior to making a final determination on this proposed rule, we will take into consideration all relevant comments and additional information received during the comment period.

If you wish to comment, you may submit your comments by any one of several methods. You may mail comments to the address specified in **ADDRESSES.** You may also hand-deliver comments to the address specified in **ADDRESSES.** You may also comment via the Internet to *PesticideESARegulations@fws.gov.* Please submit Internet comments as an ASCII file avoiding the use of special characters and any form of encryption. Please also include "Attn: 1018–AI95" and your name and return address in your Internet message. Our practice is to make comments, including names and home addresses of respondents, available for public review during regular business hours. Individual respondents may request that we withhold their home address from the rulemaking record, which we will honor to the extent allowable by law. There also may be circumstances in which we would withhold from the rulemaking record a respondent's identity, as allowable by law. If you wish us to withhold your name and/or address, you must state this prominently at the beginning of your comment. We will make all submissions from organizations or businesses, and from individuals identifying themselves as representatives of officials of organizations or businesses, available for public inspection in their entirety.

Required Determinations

Regulatory Planning and Review

In accordance with Executive Order 12866, this document is a significant proposed rule because it may raise novel legal or policy issues, and was reviewed by the Office of Management and Budget (OMB) in accordance with the four criteria discussed below.

(a) This counterpart regulation will not have an annual economic effect of $100 million or more or adversely affect an economic sector, productivity, jobs, the environment, or other units of government.

(b) This counterpart regulation is not expected to create inconsistencies with other agencies' actions. FWS and NOAA Fisheries are responsible for carrying out the Act.

(c) This counterpart regulation is not expected to significantly affect entitlements, grants, user fees, loan programs, or the rights and obligations of their recipients.

(d) OMB has determined that this rule may raise novel legal or policy issues and, as a result, this rule has undergone OMB review.

Regulatory Flexibility Act (5 U.S.C. 601 et seq.)

Under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*, as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) of 1996), whenever an agency is required to publish a notice of rulemaking for any proposed or final rule, it must prepare and make available for public comment a regulatory flexibility analysis that describes the effect of the rule on small entities (*i.e.*, small businesses, small organizations, and small government jurisdictions), unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. The Regulatory Flexibility Act requires Federal agencies to provide a statement of the factual basis for certifying that a rule will not have a significant economic impact on a substantial number of small entities.

Pursuant to the Regulatory Flexibility Act, the Secretaries of the Interior and Commerce certify that this regulation will not have a significant economic impact on a substantial number of small entities. The purpose of the rule is to increase the efficiency of the ESA section 7 consultation process for those activities involving pesticide regulation conducted by EPA. The proposed changes are expected to lead to the same protections for listed species as the section 7 consultation regulations at 50 CFR part 402.

Regulations at 50 CFR 402.04 provide that "the consultation procedures may be superseded for a particular Federal agency by joint counterpart regulations among that agency, the Fish and Wildlife Service, and the National Marine Fisheries Service." The preamble to the 1986 regulations for implementing section 7 states that "such counterpart regulations must retain the overall degree of protection afforded listed species required by the [ESA] and these regulations. Changes in the general consultation process must be designed to enhance its efficiency without elimination of ultimate Federal agency responsibility for compliance with section 7." The proposed rule will not have a significant economic impact on a substantial number of small entities for the following reasons.

(1) The proposed rule will modify procedures for formal section 7 consultation and remove the requirement for EPA to conduct informal consultation with and obtain written concurrence from FWS or NOAA Fisheries on those FIFRA actions it determines are NLAA listed species or critical habitat.

(2) The new consultation procedures may affect registrants, who provide EPA with the data used to assess the level of environmental risk. It is estimated that approximately two-thirds of the 1,850 pesticide registrants are small businesses. Because this rule is expected to streamline the consultation process and would therefore potentially accelerate the registration process for new pesticide products pesticides and the re-registration process for existing pesticides, these businesses are expected to experience no effect or a small positive effect as a result of this rule.

(3) Agricultural producers, many of which are small businesses, may be indirectly affected by this rule. Because this rule is expected to streamline the consultation process and would therefore potentially accelerate the registration process for new pesticide products pesticides and the re-registration process for existing pesticides, agricultural producers may experience a small indirect benefit from this rule.

Therefore, the Secretaries of the Interior and Commerce certify that this action will not have a significant economic impact on a substantial number of small businesses, organizations, or governments pursuant to the RFA.

Executive Order 13211

On May 18, 2001, the President issued an Executive Order (E.O. 13211) on regulations that significantly affect energy supply, distribution, and use. Executive Order 13211 requires agencies to prepare Statements of Energy Effects when undertaking certain actions. Although this rule is a significant action under Executive Order 12866, it is not expected to significantly affect energy supplies, distribution, or use. Therefore, this action is not a significant energy action and no Statement of Energy Effects is required.

Unfunded Mandates Reform Act (2 U.S.C. 1501 et seq.)

In accordance with the Unfunded Mandates Reform Act (2 U.S.C. 1501 *et seq.*):

(a) These counterpart regulations will not "significantly or uniquely" affect small governments. A Small Government Agency Plan is not required. We expect that these counterpart regulations will not result in any significant additional expenditures by entities that develop formalized conservation efforts.

(b) These counterpart regulations will not produce a Federal mandate on State, local, or tribal governments or the private sector of $100 million or greater in any year; that is, it is not a "significant regulatory action" under the Unfunded Mandates Reform Act. These counterpart regulations impose no obligations on State, local, or tribal governments.

Takings

In accordance with Executive Order 12630, these counterpart regulations do not have significant takings implications. These counterpart regulations pertain solely to ESA section 7 consultation coordination procedures, and the procedures have no impact on personal property rights.

Federalism

In accordance with Executive Order 13132, these counterpart regulations do not have significant Federalism effects. A Federalism assessment is not required. In keeping with Department of the Interior and Commerce regulations under section 7 of the ESA, we coordinated development of these counterpart regulations with appropriate resource agencies throughout the United States.

Civil Justice Reform

In accordance with Executive Order 12988, this proposed rule does not unduly burden the judicial system and meets the requirements of sections 3(a) and 3(b)(2) of the Order. We propose these counterpart regulations consistent with 50 CFR 402.04 and section 7 of the ESA.

Paperwork Reduction Act

This proposed rule would not impose any new requirements for collection of information that require approval by the OMB under the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*). This proposed rule will not impose new recordkeeping or reporting requirements on State or local governments, individuals, businesses, or organizations. 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.

National Environmental Policy Act

These counterpart regulations have been developed by FWS and NOAA Fisheries, along with EPA and USDA, according to 50 CFR 402.04. The FWS and NOAA Fisheries are considered the lead Federal agencies for the preparation of this proposed rule, pursuant to 40 CFR 1501. We have analyzed these counterpart regulations in accordance with the criteria of the National Environmental Policy Act (NEPA), the Department of the Interior Manual (318 DM 2.2(g) and 6.3(D)), and National Oceanic and Atmospheric Administration (NOAA) Administrative Order 216–6 and have determined that an environmental assessment will be prepared prior to finalization of the rule.

Government-to-Government Relationship With Indian Tribes

In accordance with the Secretarial Order 3206, "American Indian Tribal Rights, Federal-Tribal Trust Responsibilities, and the Endangered Species Act" (June 5, 1997); the President's memorandum of April 29, 1994, "Government-to-Government Relations with Native American Tribal Governments" (59 FR 22951); E.O. 13175; and the Department of the Interior's 512 DM 2, we understand that we must relate to recognized Federal Indian Tribes on a Government-to-Government basis. However, these counterpart regulations do not directly affect Tribal resources since only EPA regulatory actions are subject to the proposed provisions. The intent of these counterpart regulations is to streamline the consultation process; therefore, any indirect effect would be wholly beneficial.

List of Subjects in 50 CFR Part 402

Endangered and threatened species.

Proposed Regulation Promulgation

Accordingly the Services propose to amend part 402, title 50 of the Code of Federal Regulations as follows:

PART 402—[AMENDED]

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

Authority: 16 U.S.C. 1531 *et seq.*

2. Add a new Subpart D to read as follows:

Subpart D—Counterpart Regulations Governing Actions by the U.S. Environmental Protection Agency Under the Federal Insecticide, Fungicide and Rodenticide Act

Sec.

402.48 Conference on proposed species or proposed critical habitat.

Subpart D—Counterpart Regulations Governing Actions by the U.S. Environmental Protection Agency Under the Federal Insecticide, Fungicide and Rodenticide Act

§ 402.40 Definitions.

The definitions in § 402.02 are applicable to this subpart. In addition, the following definitions are applicable only to this subpart.

(a) *Alternative consultation agreement* is the agreement described in § 402.45.

(b) *Effects determination* is a written determination by the U.S. Environmental Protection Agency (EPA) addressing the effects of a FIFRA action on listed species or critical habitat. The contents of an effects determination will depend on the nature of the action. An effects determination submitted under § 402.46 or § 402.47 shall contain the information described in § 402.14(c)(1)–(6) and a summary of the information on which the determination is based, detailing how the FIFRA action affects the listed species or critical habitat. EPA may consider the following additional sections for inclusion in an effects determination:

(1) A conclusion whether or not the FIFRA action is likely to jeopardize the continued existence of any listed species or result in the destruction or adverse modification of critical habitat and a description of any reasonable and prudent alternatives that may be available;

(2) A description of the impact of any anticipated incidental taking of such listed species resulting from the FIFRA action, reasonable and prudent measures considered necessary or appropriate to minimize such impact, and terms and conditions necessary to implement such measures; and

(3) A summary of any information or recommendations from an applicant. An effects determination shall be based on the best scientific and commercial data available.

(c) *FIFRA action* is an action by EPA to approve, permit or authorize the sale, distribution or use of a pesticide under sections 136–136y of the Federal Insecticide, Fungicide and Rodenticide Act, 7 U.S.C. 136 *et seq.* (FIFRA). In any consultation under this subpart, EPA shall determine the nature and scope of a FIFRA action.

(d) *Listed species* is a species listed as endangered or threatened under section 4 of the Act.

(e) *Partial biological opinion* is the document provided under § 402.47(a), pending the conclusion of consultation under § 402.47(b), stating the opinion of the Service as to whether or not a FIFRA action is likely to jeopardize the continued existence of one or more listed species or result in the destruction or adverse modification of one or more critical habitats, and describing the impact of any anticipated incidental taking of such listed species resulting from the FIFRA action, reasonable and prudent measures considered necessary or appropriate to minimize such impact, and terms and conditions necessary to implement such measures.

(f) *Service Director* refers to the Director of the U.S. Fish and Wildlife Service or the Assistant Administrator for Fisheries for the National Oceanic and Atmospheric Administration.

(g) *Service Representative* is the person or persons designated to participate in advance coordination as provided in this subpart. The Service may designate more than one individual to serve jointly as a Service Representative.

§ 402.41 Purpose.

The purpose of these counterpart regulations is to enhance the efficiency and effectiveness of the existing consultation process under section 7 of the Endangered Species Act (Act), 16 U.S.C. 1531 *et seq.*, by providing Fish and Wildlife Service and the National Marine Fisheries Service (referred to jointly as "Services" and individually as "Service") and EPA with additional means to satisfy the requirements of section 7(a)(2) of the Act for certain regulatory actions under FIFRA. These additional means will permit the Services and EPA to more effectively use the scientific and commercial data generated through the FIFRA regulatory process as part of the best scientific and commercial data available to protect listed species and critical habitat. The procedures authorized by these counterpart regulations will be as protective of listed species and critical habitat as the process established in subpart B of this part.

§ 402.42 Scope and applicability.

(a) Available consultation procedures. This Subpart describes consultation procedures available to EPA to satisfy the obligations of section 7(a)(2) of the Act in addition to those in subpart B of this part for FIFRA actions authorized, funded, or carried out by EPA in which EPA has discretionary Federal involvement or control. EPA retains discretion to initiate early, informal, or formal consultation as described in §§ 402.11, 402.13, and 402.14 for any FIFRA action. The procedures in this Subpart may be employed for FIFRA actions as follows:

(1) Interagency exchanges of information under § 402.43 and advance coordination under § 402.44 are available for any FIFRA action.

(2) Alternative consultation under § 402.45 is available for a listed species or critical habitat if EPA determines the FIFRA action is not likely to adversely affect the listed species or critical habitat.

(3) Optional formal consultation under § 402.46 is available for any FIFRA action with respect to any listed species or critical habitat.

(4) The special procedures in § 402.47 are available for consultations on FIFRA actions that will be unusually complex due to factors such as the geographic area or number of species that may be affected by the action.

(5) EPA shall engage in consultation as to all listed species and critical habitat that may be affected by a FIFRA action, and may in its discretion employ more than one of the available consultation procedures for a FIFRA action that may affect more than one listed species or critical habitat.

(6) EPA shall engage in consultation on actions involving requests for emergency exemptions under section 18 of FIFRA that may affect listed species or critical habitat, and may choose to do so under § 402.05 or other provisions of this subpart or subpart B of this part. Any required formal consultation shall be initiated as soon as practicable after the emergency is under control. For the purposes of § 402.05(b) the definition of formal consultation in § 402.02 includes the procedures in § 402.46.

(7) EPA must prepare a biological assessment for a FIFRA action to the extent required by § 402.12.

(8) EPA must comply with § 402.15 for all FIFRA actions.

(9) After a consultation under this subpart has been concluded, EPA shall reinitiate consultation as required by § 402.16 as soon as practicable after a circumstance requiring reinitiation occurs, and may employ the procedures in this subpart or subpart B of this part in any reinitiated consultation.

(b) *Exchanges of scientific information.* As part of any of the additional consultation procedures provided in this subpart, EPA and the Services shall establish mutually-agreeable procedures for regular and timely exchanges of scientific information to achieve accurate and informed decision-making under this subpart and to ensure that the FIFRA process considers the best scientific and commercial data available on listed species and critical habitat in a manner consistent with the requirements of FIFRA and ESA.

§ 402.43 Interagency exchanges of information.

EPA may convey to the Service a written request for a list of any listed species or critical habitat that may be present in any area that may be affected by a FIFRA action. Within 30 days of receipt of such a request the Service shall advise EPA in writing whether, based on the best scientific and commercial data available, any listed species or critical habitat may be present in any such area. EPA may thereafter request the Service to provide available information (or references thereto) describing the applicable environmental baseline for each species or habitat that EPA determines may be affected by a FIFRA action, and the Service shall provide such information within 30 days of the request.

§ 402.44 Advance coordination for FIFRA actions.

(a) *Advance coordination.* EPA may request the Service to designate a Service Representative to work with EPA in the development of an effects determination for one or more listed species or critical habitat. EPA shall make such a request in writing and shall provide sufficient detail as to a FIFRA action planned for consultation to enable the Service to designate a representative with appropriate training and experience who shall normally be available to complete advance coordination with EPA within 60 days of the date of designation. Within 14 days of receiving such a request, the Service shall advise EPA of the designated Service Representative.

(b) *Participation of Service Representative in preparation of effects determination.* The Service Representative designated under paragraph (a) of this section shall participate with EPA staff in the preparation of the effects determination identified under paragraph (a) of this section. EPA shall use its best efforts to include the designated Service Representative in all relevant discussions on the effects determination, to provide the designated Service Representative with access to all documentation used to prepare the effects determination, and to provide the designated Service Representative office and staff support sufficient to allow the Service Representative to participate meaningfully in the preparation of the effects determination. EPA shall consider all information timely identified by the designated Service Representative during the preparation of the effects determination.

§ 402.45 Alternative consultation on FIFRA actions that are not likely to adversely affect listed species or critical habitat.

(a) *Consultation obligations for FIFRA actions that are not likely to adversely affect listed species or critical habitat when alternative consultation agreement is in effect.* If EPA and the Service have entered into an alternative consultation agreement as provided below, EPA may make a determination that a FIFRA action is not likely to adversely affect a listed species or critical habitat without informal consultation or written concurrence from the Director, and upon making such a determination for a listed species or critical habitat, EPA need not initiate any additional consultation on that FIFRA action as to that listed species or critical habitat. As part of any subsequent request for formal consultation on that FIFRA action under this subpart or subpart B of this part, EPA shall include a list of all listed species and critical habitat for which EPA has concluded consultation under this section.

(b) *Procedures for adopting and implementing an alternative consultation agreement.* EPA and the Service may enter into an alternative consultation agreement using the following procedures:

(1) *Initiation.* EPA submits a written notification to the Service Director of its intent to enter into an alternative consultation agreement.

(2) *Required contents of the alternative consultation agreement.* The alternative consultation agreement will, at a minimum, include the following components:

(i) *Adequacy of EPA Determinations under the ESA.* The alternative consultation agreement shall describe actions that EPA and the Service have taken to ensure that EPA's determinations regarding the effects of its actions on listed species or critical habitat are consistent with the ESA and applicable implementing regulations.

(ii) *Training.* The alternative consultation agreement shall describe actions that EPA and the Service intend to take to ensure that EPA and Service personnel are adequately trained to carry out their respective roles under the alternative consultation agreement. The alternative consultation agreement shall provide that all effects determinations made by EPA under this Subpart have been reviewed and concurred on by an EPA staff member who holds a current certification as having received appropriate training under the alternative consultation agreement.

(iii) *Incorporation of new information.* The alternative consultation agreement shall describe processes that EPA and the Service intend use to ensure that new information relevant to EPA's effects determinations is timely and appropriately considered.

(iv) *Incorporation of scientific advances.* The alternative consultation agreement shall describe processes that EPA and the Service intend to use to ensure that the ecological risk assessment methodologies supporting EPA's effects determinations incorporate relevant scientific advances.

(v) *Oversight.* The alternative consultation agreement shall describe the program and associated record keeping procedures that the Service and EPA intend to use to evaluate EPA's processes for making effects determinations consistent with these regulations and the alternative consultation agreement. The alternative consultation agreement shall provide that the Service's oversight will be based on periodic evaluation of EPA's program for making effects determinations under this Subpart. Periodic program evaluation will occur at the end of the first year following signature of the alternative consultation agreement and should normally occur at least every five years thereafter.

(vi) *Records.* The alternative consultation agreement shall include a provision for EPA to maintain a list of FIFRA actions for which EPA has made determinations under this section and to provide the list to the Services on request. EPA will also maintain the necessary records to allow the Service to complete program evaluations.

(vii) *Review of Alternative Consultation Agreement.* The alternative consultation agreement shall include provisions for regular review and, as appropriate, modification of the agreement by EPA and the Service, and for departure from its terms in a particular case to the extent deemed necessary by both EPA and the Service.

(3) *Training.* After EPA and the Service enter into the alternative consultation agreement, EPA and the Service will implement the training program outlined in the alternative consultation agreement to the mutual satisfaction of EPA and the Service.

(4) *Public availability.* The alternative consultation agreement and any related oversight or monitoring reports shall be made available to the public to the extent provided by law.

(c) *Oversight of alternative consultation agreement implementation.* Through the program evaluations set forth in the alternative consultation agreement, the Service will determine whether the implementation of this section by EPA is consistent with the best scientific and commercial information available, the ESA, and applicable implementing regulations. The Service Director may use the results of the program evaluations described in the alternative consultation agreement to recommend changes to EPA's implementation of the alternative consultation agreement. The Service Director retains discretion to terminate the alternative consultation agreement if, in using the procedures in this subpart, EPA fails to comply with the requirements of this subpart, section 7 of the ESA, or the terms of the alternative consultation agreement. Termination, suspension, or modification of an alternative consultation agreement does not affect the validity of any NLAA determinations made previously under the authority of this Subpart.

§ 402.46 Optional formal consultation procedure for FIFRA actions.

(a) *Initiation of consultation.* EPA may initiate consultation on a FIFRA action under this section by delivering to the Service a written request for consultation. The written request shall be accompanied by an effects determination prepared in accordance with § 402.40(b) and a list or summary of all references and data relied upon in the determination. All such references and data shall be made available to the Service on request and shall constitute part of the Service's administrative record for the consultation. The time for conclusion of the consultation under section 7(b)(1) of the Act is calculated from the date the Service receives the written request from EPA. Any subsequent interchanges regarding EPA's submission, including interchanges about the completeness of the effects determination, shall occur during consultation and do not extend the time for conclusion of the consultation unless EPA withdraws the request for consultation.

(b) *Additional information determination.* For an effects determination prepared without advance coordination under § 402.44, the Service may determine that additional available information would provide a better information base for the effects determination, in which case the Service Director shall notify the EPA Administrator within 45 days of the date the Service receives the effects determination. The notification shall describe such additional information in detail, and shall identify a means for obtaining that information within the time period available for consultation. EPA shall provide a copy of the Service Director's notification to any applicant. EPA may thereafter revise its effects determination, and may resubmit the revised effects determination to the Service. If EPA advises the Service it will not resubmit a revised effects determination to the Service, its initiation of consultation on the effects determination is deemed withdrawn.

(c) *Service responsibilities.* (1) Within the later of 90 days of the date the Service receives EPA's written request for consultation or 45 days of the date the Service receives an effects determination resubmitted under paragraph (b) of this section, and consistent with section 7(b)(1) of the Act, the Service shall take one of the following actions:

(i) If the Service finds that the effects determination contains the information required by § 402.40(b) and satisfies the requirements of section 7(b)(4) of the Act, and the Service concludes that the FIFRA action that is the subject of the consultation complies with section 7(a)(2) of the Act, the Service will issue a written statement adopting the effects determination; or

(ii) The Service will provide EPA a draft of a written statement modifying the effects determination, which shall meet the requirements of § 402.14(i), and as modified adopting the effects determination, and shall provide a detailed explanation of the scientific and commercial data and rationale supporting any modification it makes; or

(iii) The Service will provide EPA a draft of a biological opinion finding that the FIFRA action is likely to jeopardize the continued existence of a listed species or result in the destruction or adverse modification of critical habitat, and describing any reasonable and prudent alternatives if available.

(2) If the Service acts under paragraphs (c)(1)(ii) or (c)(1)(iii) of this section, EPA shall, on request from an applicant, provide the applicant a copy of the draft written statement or draft biological opinion received from the Service. The Service shall at the request of EPA or an applicant discuss with EPA and the applicant the Service's review and evaluation under this section, and the basis for its findings. EPA and any applicant may submit written comments to the Service within 30 days after EPA receives the draft written statement or opinion from the Service unless the Service, EPA and any applicant agree to an extended deadline consistent with section 7(b)(1) of the Act.

(3) The Service will issue a final written statement or final biological opinion within 45 days after EPA receives the draft statement or opinion from the Service unless the deadline is extended under section 7(b)(1) of the Act.

(d) Opinion of the Secretary. The written statement or opinion by the Service under paragraphs (c)(1) or (c)(3) of this section shall constitute the opinion of the Secretary and the incidental take statement, reasonable and prudent measures, and terms and conditions under section 7(b) of the Act.

(e) *Delegation of Authority for Service decisions.* Any written statement modifying an effects determination or any biological opinion issued under this section shall be signed by the Service Director and such authority may not be delegated below the level of Assistant Director for Endangered Species (FWS) or Director of Office of Protected Resources (NOAA Fisheries).

§ 402.47 Special consultation procedures for complex FIFRA actions.

(a) *Successive effects determinations.* If EPA determines after conferring with the Service that consultation on a FIFRA action will be unusually complex due to factors such as the geographic area or number of species that may be affected by the action, EPA may address the effects of the action through successive effects determinations under this Subpart addressing groupings or categories of species or habitats as established by EPA. EPA may initiate consultation based upon each such effects determination using the procedure in § 402.46(a), and the provisions of § 402.46(b) and (c) shall apply to any such consultation. When consultation is conducted under this section, the written statement or opinion provided by the Service under § 402.46(c) constitutes a partial biological opinion as to the species or habitats that are the subject of the consultation. While not constituting completion of consultation under section 7(a)(2), EPA retains authority to use such a partial biological opinion along with other available information in making a finding under section 7(d) of the Act.

(b) Opinion of the Secretary. After conclusion of all consultation on the FIFRA action, the partial biological opinions issued under paragraph (a) of this section shall then collectively constitute the opinion of the Secretary and the incidental take statement, reasonable and prudent measures, and terms and conditions under section 7(b) of the Act except to the extent a partial biological opinion is modified by the

Service in accordance with the procedures in § 402.46(c). The Service shall so advise EPA in writing upon issuance of the last partial biological opinion for the consultation.

§ 402.48 Conference on proposed species or proposed critical habitat.

EPA may employ the procedures described in § 402.10 to confer on any species proposed for listing or any habitat proposed for designation as critical habitat. For the purposes of § 402.10(d), the procedures in § 402.46 are a permissible form of formal consultation.

Dated: January 27, 2004.

Paul Hoffman,

Acting Assistant Secretary for Fish and Wildlife and Parks.

Dated: January 26, 2004.

William T. Hogarth,

Assistant Administrator for Fisheries, National Oceanic and Atmospheric Administration.

[FR Doc. 04–1963 Filed 1–28–04; 10:11 am]

BILLING CODE 4310–55–P

Notices

Federal Register
Vol. 69, No. 20
Friday, January 30, 2004

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

Forest Service

Robert Wedge Post Fire Project, Flathead National Forest, Flathead County, MT

AGENCY: Forest Service, USDA.

ACTION: Notice; intent to prepare environmental impact statement.

SUMMARY: The Forest Service will prepare an environmental impact statement (EIS) for a resource management project within the Robert and Wedge Canyon Fire Areas which burned approximately 13,000 acres and 21,000 acres respectively on National Forest System lands in July-September of 2003. The project area is on the Hungry Horse/Glacier View Ranger District, Flathead National Forest, and is bordered on the east by Glacier National Park and the North Fork of the Flathead River. The city of Columbia Falls, Montana is located approximately 8 miles south of the Robert Fire and approximately 40 miles south of the Wedge Canyon Fire.

DATES: Substantive comments concerning the proposed project and analysis should be received in writing on or before February 27, 2004. A public scoping meeting will be held in the town of Kalispell, Montana in February of 2004. The draft environmental impact statement (DEIS) is expected to be filed with the Environmental Protection Agency and made available for public review in May 2004. The final environmental impact statement (FEIS) is expected to be published in September 2004.

ADDRESSES: Substantive comments should be submitted to Project Leader, Robert Wedge Post Fire Project, P.O. Box 190340, Hungry Horse, Montana 59919, fax (406) 387–3889 or electronically to *comments-northern-flathead-hungry-horse-glacier-view@fs.fed.us* Substantive comments are those with the scope of, are specific to, and have a direct relationship to the proposed action, and include supporting reasons that the Responsible Official should consider in reaching a decision. Comments received in response to this request will be available for public inspection and will be released in their entirety if requested pursuant to the Freedom of Information Act.

FOR FURTHER INFORMATION CONTACT: Kathy Ramirez, Project Leader, (208) 331–5908, fax (208) 387–0842 or *kramirez@fs.fed.us.*

SUPPLEMENTARY INFORMATION: This project proposal will be conducted under Title IV—The Flathead and Kootenai National Forest Rehabilitation Act which was included in the Department of Interior and Related Agencies Appropriations Act of 2004 and approved by President Bush in November 2003. The findings of this title include that the Robert and Wedge fires of 2003 caused extensive resource damage on the Flathead National Forest, and the rehabilitation of burned areas needs to be completed in a timely manner in order to reduce the long-term environmental impacts. Wildlife and watershed resource values will be maintained in areas effected by the Robert and Wedge fires while exempting the rehabilitation effort from certain applications of the National Environmental Policy Act and the Clean Water Act.

This environmental impact statement will not be required to study, develop, or describe any alternative to the proposed agency action. Consistent with the Clean Water Act and Montana Code 75–703(10)(b), the Secretary is not prohibited from implementing projects under this title due to a lack of Total Maximum Daily Load as provided for under section 303(d) of the Clean Water Act, except that the Secretary shall comply with any best management practices required by the State of Montana. If a consultation is required under section 7 of the Endangered Species Act for a project under this title, the Secretary of Interior shall expedite and give precedence to such consultation over any similar requests.

To encourage meaningful participation during preparation of a project under this title, the Secretary shall facilitate collaboration among the State of Montana, local governments, and Indian tribes, and participation of interested persons, in a manner consistent with the Implementation Plan for the 10 year Comprehensive Strategy of a Collaborative Approach for reducing Wildland Fire Risks to Communities and the Environment (May 2002).

A collaborative process involving over 100 participants occurred January 5–10 of 2004 in Kalispell, Montana, to develop ideas for restoration, salvage and road management in areas affected by the Robert and Wedge Canyon Fires. The entire group came to agreement on the following statements; coordinate salvage entries with other rehabilitation treatments, protect sites as necessary with horizontal placement and retention of woody debris, complete salvage harvest in a timely manner to maximize economic return, utilize Best Management Practices to minimize soil erosion and protect water quality, and in some riparian areas, where INFISH rules can be met, salvage, restoration, rehabilitation, reforestation shall occur. The results of this collaborative process were used to guide the proposed action. The purpose of the proposal is to recover merchantable wood fiber affected by the Robert and Wedge Canyon Fires in a timely manner to support local communities, contribute to the long term yield of forest products and to rehabilitate areas within the fire perimeters to enhance site productivity.

The proposed action includes salvage harvest of approximately 4500 acres of fire killed or tree damaged by the fires and likely to die. An estimated 35 million board of timber would be available for harvest using tractor, cable, and helicopter logging systems. Planting of conifer seedlings would also be included.

Access for salvage would include the use of existing classified and unclassified roads. Ground based logging would require new temporary roads that would be recontoured or rehabilitated after logging activities. No new permanent roads would be constructed for salvage activities. The proposed action does not include timber harvest or temporary road construction in Inventoried Roadless Areas (IRAs).

The proposed action would include activities to modify wheeled motorized access within the Lower Whale and Canyon McGinnis grizzly bear subunits to improve grizzly bear security.

Approximately 5 miles of open yearlong/seasonally open road would be restricted yearlong and 16 miles of road would be decommissioned in both grizzly bear subunits. The Flathead Forest Plan has open motorized access, total motorized access, and security core standards that would be amended with a project specific amendment in this project.

More detailed scoping information and maps can be accessed on the Flathead National Forest Internet site at *http://www.fs.fed.us/rl/flathead/*.

This EIS will tier to the Flathead National Forest Land and Resource Management Plan and EIS of January 1986, and its subsequent amendments, which provides overall guidance for land management activities on the Flathead National Forest.

Preliminary issues and concerns with the proposal include potential impacts on threatened and endangered species such as grizzly bear, lynx, and bull trout, and on motorized access. Alternatives being considered at this time are this proposed action and the no action alternative.

The comment period on the draft environmental impact statement will be 45 days from the date the Environmental Protection Agency publishes the notice of availability in the **Federal Register**.

The Forest Service believes it is important to give reviewers notice at this early stage of several court rulings related to public participation in the environmental review process. First, reviewers of draft environmental impact statements 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 but that are not raised until after completion of the final environmental impact statement may be waived or dismissed by the courts. *Wisconsin Heritages, Inc.* v. *Harris*, 490 F. Supp. 1334, 1338 (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 them 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 statement. 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).

The Responsible Official is the Forest Supervisor of the Flathead National Forest, 1935 3rd Avenue East, Kalispell, Montana 59901. The Forest Supervisor will make a decision regarding this proposal considering the comments and responses, environmental consequences discussed in the final EIS, and applicable laws, regulations, and policies. The Responsible Official will decide whether or not to select the proposed action, and if so, what design features and/or mitigation measures would be applied to proposed activities. The decision and rationale for the decision will be documented in a Record of Decision. That decision will be subject to appeal under applicable Forest Service regulations.

Dated: January 22, 2004.

Cathy Barbouletos,

Forest Supervisor—Flathead National Forest.

[FR Doc. 04–1766 Filed 1–29–04; 8:45 am]

BILLING CODE 3410–11–M

DEPARTMENT OF AGRICULTURE

Forest Service

Nebraska National Forest—Bessey and Pine Ridge Ranger Districts, Samuel R. McKelvie National Forest, and Oglala National Grassland Nebraska; Travel Management-Nebraska and Samuel R. McKelvie National Forests and Oglala National Grassland

AGENCY: Forest Service, USDA.

ACTION: Notice of intent to prepare an environmental impact statement.

SUMMARY: The Nebraska National Forest—Bessey and Pine Ridge Ranger Districts, Samuel R. McKelvie National Forest, and Oglala National Grassland are proposing to manage travel, primarily, but not exclusively motorized travel, by implementing limitations on where and when various types of travel can take place on the national forests and national grassland in Nebraska.

Comments received during the recent Land and Resource Management Plan Revision made it clear that the existing travel policy of "open (to motorized travel) unless designated closed," is unacceptable to a significant segment of national forest and grassland visitors. Forest Service Chief, Dale Bosworth, recently identified unmanaged recreation, primarily Off-Highway Vehicle (OHV) use as one of four major threats to the national forests and grasslands.

In addition, forest budgets for road maintenance do not allow the existing road system to be maintained to the identified standards, and in some cases, negative impacts to resources can be attributed to motorized vehicle use.

The intended effect of implementing limitations on motorized travel on the national forests and grassland in Nebraska will be to reduce user conflicts, reduce road maintenance costs, and reduce resource degradation where it can be attributed to the use of motorized, or non-motorized travel.

DATES: To be considered in the process of determining the scope of the analysis and finalizing alternatives comments must be received by March 15, 2004. The draft environmental impact statement is expected to be available for review and comment June 2004 and the final environmental impact statement is expected in October 2004.

ADDRESSES: For additional information, or to send written comments, contact the Travel Management Team Leader, Nebraska National Forest, 125 North Main Street, Chadron, NE, 69337, Attention: Jerry Schumacher. Comments may also be provider electronically by sending them to: *comments-rocky-mountain-nebraska@fs.fed.us*

FOR FURTHER INFORMATION CONTACT: For questions or information specific to the Nebraska National Forest—Bessey Ranger District or Samuel R. McKelvie National Forest, contact Patti Barney, District Ranger, USDA Forest Service, Bessey Ranger District, PO Box 39, Halsey, NE 69142–0038, Ph. 308–533–2257. For questions or information specific to the Nebraska National Forest—Pine Ridge ranger District or Oglala National Grassland, contact Charlie Marsh, District Ranger, USDA Forest Service, Pine Ridge Range District, 1240 West 16th St., Chadron, NE 69337–7364. Ph. 308–432–4475.

SUPPLEMENTARY INFORMATION: The Record of Decision (ROD) for the Nebraska and Samuel R. McKelvie National Forests, Oglala, Buffalo Gap, and Fort Pierre National Grasslands Land and Resource Management Plan (LRMP) was signed on July 31, 2002.

The LRMP Record of Decision directed that motorized travel on the

Nebraska National Forest units change from "open unless designated closed," to "closed unless designated open." The ROD allowed off-road motorized travel "to continue in compliance with Forest Supervisor special orders for travel restrictions until site-specific analysis with public involvement has been accomplished for the purpose of designating permanent transportation facilities." (ROD, p. 43).

The Forest Leadership Team agreed to proceed with the analysis for those units located in Nebraska during fiscal year 2004, followed by those units located in South Dakota in FY 2005.

Comments provided during the planning process included many references to values of the public lands in promoting family activities associated with hunting and OHV riding as well as the economic values to neighboring communities from participation in these activities. Others point to the risk to environmental and historic resources. Many focus upon the experiences that are available, for the most part, only on national forests and grasslands. Motorized access contributes to the use and enjoyment of NFS lands to a greater or lesser extent for nearly all users.

Purpose and Need for Action

Need: The need for this Travel Management Plan is to protect the public's national forest and national grassland resources while providing quality outdoor experiences within the capability of the ecosystems and projects funding levels. The scope of the plan includes the Nebraska National Forest, the Samuel R. McKelvie National Forest and the Oglala National Grassland in Nebraska.

Purpose: The purpose of this Travel Management Plan is to identify routes, areas, and times where motorized and non-motorized travel will be allowed on the Nebraska National Forest, the Samuel R. McKelvie National Forest and the Oglala National Grassland in Nebraska.

Proposed Action

Alternative #2—Proposed Action

NNF, Pine Ridge Ranger District and Oglala National Grassland

Motorized Travel

Vehicles over 50″ width or licensed to travel on Nebraska's highways are allowed on all designated Forest System Roads (FSR) on the Pine Ridge Ranger District and Oglala National Grassland.

Vehicles under 50″ width are allowed on one trail on the Pine Ridge (approximately 12 miles) and no Forest System Roads on the Pine Ridge.

All motorized vehicles are allowed to travel off designated roads from january1 6 through August 14 annually on the Oglala National Grassland.

All motorized vehicles are allowed on all designated FSR roads on the Oglala National Grassland. Note: May require a Forest Service Special order.

ATV's as defined by state law are prohibited on those roads and highways under state or county jurisdiction. Those roads are:

FSR 926—Cemetery Road—Sioux County jurisdiction
FSR 904—Old Hwy 2 (Toadstool Road)—questions on jurisdiction (pvt., FS, Dawes, Sioux)
FSR 902—2.5W—Cottonwood Road—Dawes/Sioux County jurisdiction
FSR 905—Sand Creek Road—Sioux County jurisdiction
FSR 907—6.5S—Milo Road—Sioux County jurisdiction
FSR 914—Montrose Road—Sioux County jurisdiction
FSR 915—Edgemont Road—Sioux County jurisdiction
FSR 916—Indian Creek Road—Sioux County jurisdiction
FSR 918—Orella Road—Sioux County jurisdiction
FSR 919—Lone Tree/Snook Roads—Dawes County jurisdiction
FSR 934—McMeekin Road—Dawes County jurisdiction
State Hwy. 2/71, Dawes/Sioux Counties, State of Nebr. jurisdiction

Snow machines are allowed to travel cross-country on the national forest and national grassland except where motorized restrictions apply. They are not allowed on FSR's but may travel parallel to the road.

NNF, Pine Ridge and Oglala National Grassland

Other Travel Restrictions

All travel is prohibited on the trails south of the Cliffs Area between May 15 and July 15, annually.

FSR 733, which accesses Spotted Tail Trailheads, is open from sunrise to sunset only.

Mountain bike trail is allowed only on designated roads and trails outside of Soldier Creek Wilderness on the Pine Ridge.

Bison Trail is open to non-motorized travel only.

Existing FSR's To Be Closed in Part or in Total on the Pine Ridge

718—approximately two miles
725—all—approximately 3 miles
724—approximately one mile
726—approximately 1.5 miles
803—convert to non-motorized trail
804—convert to non-motorized trail

Existing FSR's To Be Closed in Part or in Total on the Oglala National Grassland

931—approximately one mile
929—approximately one mile
923—approximately 1.75 miles
913—approximately 1.75 miles

PINE RIDGE DISTRICT AND OGLALA NATIONAL GRASSLAND

[Total = 144,703 total acres]

Number of acres currently with non-motorized status:	
Soldier Creek Wilderness	7794
Management area 1.31 Backcountry non-motorized	1830
Pine Ridge NRA (MA 1.31a)	6600
Pine Ridge Trail	173
Special interest areas—non-motorized	2048
Administrative sites	126
Total non-motorized	18,571
Total motorized	126,132
Percent non-motorized	12.8

Alternative #2—Proposed Action

NNF, Bessey Ranger District and Samuel R. McKelvie National Forest

Motorized Travel—Bessey District

Vehicles over 50″ width or licensed for operation on state highways are allowed on:

FSR 201
FSR 203 (Circle Road),
FSR 2211
FSR 212 (Natick Road),
FSR 214
FSR 228
FSR 259 Gaston Road)
FSR 277 (Whitetail Road)

Motorized vehicles 50″ in width and under are the only methods of travel allowed on the Dismal River Trail

All motorized travel allowed on FSR 20a, 211, 214, and 228. May need a Forest Service Special order.

Areas Open to Off-Road Motorized Travel

Hill Climb area on FSR 214 in Section 25 of Stoltenberg Allotment. (10 acres approx.)

Dismal River Play Area between FSR 277 and the Dismal River by Whitetail Campground (10 acres approx.)

Other Travel Restrictions—Bessey Ranger District and Samuel R. McKelvie NF

Horse travel allowed everywhere except Bessey Recreation Complex, Scott Lookout National Recreation Trail, and Porcupine North Allotment.

Foot traffic only is allowed on the Scott Lookout National Recreation Trail. Wheel chairs or other mobility assistance devices required for normal daily activities are allowed.

Horse travel is allowed everywhere on the Samuel R. McKelvie NF except the Bluebird trail and within Steer Creek Campground.

Existing FSR's Closed in Part or in Total on the Bessey Ranger District

FSR 222—totally closed, approximately one mile
FSR 258—totally closed, approximately .75 miles
FSR 263—totally closed, approximately 5 miles
FSR 202—totally closed, approximately 2.5 miles

BESSEY RANGER DISTRICT

[Total acres (90,465)]

Number of acres currently in non-motorized status:	
Signal Hill Research Natural Area	504
Scott Lookout National Recreation Trail	22
Seasonal motorized restriction (Sept. 1—Nov. 30)	29,000
Total	29,526
Percent non-motorized	32.6

Motorized Travel—Samuel R. McKelvie National Forest

All motorized travel is allowed on:

FSR 601
FSR 602
FSR 603
FSR 604
FSR 605
FSR 621
FSR 626 to windmill #144 enclosure
Unclassified Road from FSR 603 by windmill #173 to FSR 602 by windmill #153
Unclassified Road from FSR 603 by windmill #223 to FSR 602 near windmill #203

Note: May require a special order. No off-road motorized travel is allowed.

Existing FSR's closed in part, or in total on the Samuel R. McKelvie NF—None.

SAMUEL R. MCKELVIE NF

[Total acres (116,079)]

Number of acres currently in non-motorized status:	
Steer Creek Research Natural Area	2500
Total	2500
Percent non-motorized	2.2

Possible Alternatives

The Forest Plan Record of Decision directs that "Motorized use is allowed to continue on existing travel routes until a site-specific analysis with public involvement has been accomplished for the purpose of designating the permanent transportation facilities."

Preliminary Alternative #1—Existing Condition

All areas are designated as open to travel under current conditions. Motorized travel is allowed wherever and whenever it is not currently restricted. Current restrictions on motorized travel include:

Nebraska National Forest, Pine Ridge District/Oglala National Grassland

Soldier Creek Management Unit—9600 acres
Pine Ridge National Recreation Area and adjacent "keyhole"—6900 acres approx.
Pine Ridge Trail
Bur Oak Enclosure SIA—3 acres
Hudson-Meng Bison Bonebed Special Interest Area (SIA)—40 acres
Toadstool Geologic Park SIA—2000 acres
Quaking Aspen Stand SIA—8 acres

Mechanized travel, such as mountain bikes or game carts, is prohibited in Soldier Creek Wilderness.

Nebraska National Forest, Bessey Ranger District/Samuel R. McKelvie National Forest

Motorized travel within the area enclosed by Circle road (FSR 203) and Natick Road (FSR 212) is allowed on those roads only from September 1 through November 30 annually.

ATV travel is prohibited on:

State Spur 86B
Circle Road (FSR 203)
Gaston Road (FSR 259)
Natick Road (FSR 212)
Whitetail Road (FSR 277) and
The area adjacent to Scott Fire Lookout Tower

Motorized travel is also prohibited in the 500-acre Signal Hill Research Natural Area (RNA)—Bessey Ranger District and the 2500-acre Steer Creek RNA—SR McKelvie NF, except on FSR 601 and 602.

Foot traffic only is allowed on the Scott Lookout National Recreation Trail.

Alternative #3—To Be Developed, if Needed, Upon Completion of Scoping

Responsible Official

There will be two Records of Decision that result from the analysis conducted in this EIS. The responsible official for the travel management decision relating to the Nebraska National Forest, Bessey Ranger District and Samuel R. McKelvie National Forest is District Ranger, Patti Barney, PO Box 39, Halsey, NE 69142–0038, Ph. 308–533–2257.

The responsible official for the decision relating to the Nebraska National Forest, Pine Ridge Ranger District and Oglala National Grassland is District Ranger, Charles R. Marsh, 1240 West 16th St., Chadron, NE 69337–7364, Ph. 308–432–4475.

Nature of Decision To Be Made

The decisions to be made will detail the permanent travel facilities for the Nebraska National Forest, Bessey and Pine Ridge Ranger Districts, Samuel R. McKelvie National Forest; and Oglala National Grassland in Nebraska.

The decisions will designate travelways and areas where specific types of travel are allowed, identify the uses allowed on those travelways/areas, and describe any timing limitations during which specific types of travel are not allowed.

Scoping Process

The scoping process will officially begin with publication of this Notice of Intent in the **Federal Register**. Prior to its publication, the forest revised its Land and Resource Management Plan (Record of Decision signed July 31, 2002) during the analysis of which there were comments directed toward the topic of travel management. The decision was made to address the topic separately from the Plan revision effort, but comments have been saved from that effort.

Additionally, the quarterly Schedule of Proposed Actions for September and December, 2003 indicated that travel management would be addressed, with a decision expected by October, 2004.

In the summer and fall of 2003, the affected national forest and grassland units began to distribute a contact response form to those forest visitors who wished to be provided with information about upcoming opportunities to participate in the public involvement process.

Six scoping meetings are scheduled across Nebraska at the following places and dates:

January 7, 2004, (5 p.m.–7 p.m. and 7 p.m.–9 p.m.), Chadron State College Student Center, Scottsbluff Room, 10th and Shelton Streets, Chadron, NE
January 8, 2004, (5 p.m.–7 p.m. and 7 p.m.–9 p.m.), Gering Civic Center, 1050 M St., Gering, NE
January 12, 2004, (5 p.m.–7 p.m. and 7 p.m.–9 p.m.), Howard Johnson's Riverside Inn, 3333 Ramada Drive, Grand Island, NE
January 13, 2004, (5 p.m.–7 p.m. and 7 p.m.–9 p.m.), Best Western Villager Courtyard and Gardens, 5200 O Street, Lincoln, NE

January 14, 2004, (5 p.m.–7 p.m. and 7 p.m.–9 p.m.), Lifelong Learning Center, 801 East Benjamin Avenue, Norfolk, NE
January 15, 2004, (5 p.m.–7 p.m. and 7 p.m.–9 p.m.), Holiday Inn Express, 803 East Highway 20, Valentine, NE
January 20, 2004, (5 p.m.–7 p.m. and 7 p.m.–9 p.m.), Stubb's Restaurant Meeting Room, Junction Highways 2 and 83, Thedford, NE
January 21, 2004, (5 p.m.–7 p.m. and 7 p.m.–9 p.m.), Sandhills Convention Center/Quality Inn and Suites, 2102 South Jeffers Street, North Platte, NE

Preliminary Issues

The current road and trail system cannot be maintained to established standards with the current and projected budget allocations.

Unrestricted motorized travel negatively affects the recreation experience of those who are seeking prefer a non-motorized experience. This relates primarily to big game hunting, and to a lesser extent upland hunting, judging from the comments received.

In a few locations, there is evidence that motorized travel is contributing to resource degradation.

The national forests and national grassland are essentially the only public areas in the state where motorized travel is allowed.

Restricting motorized travel could contribute to a decline in rural economies that rely in part upon motorized recreation participation on the national forests and grassland.

Comment Requested

This notice of intent initiates the scoping process which guides the development of the environmental impact statement. A detailed description of the proposed action and available maps can be accessed at *http://www.fs.fed.us/r2/nebraska*. Comments that are most helpful for the Forest Service in making adjustments to the proposed action are those that provide specific suggestions for changes and include reasons and/or scientific documentation to support the requested changes. Comments that support the proposed action also are most helpful if they clearly describe why the writer favors the actions proposed.

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 statement will be 45 days form the date the Environmental Protection Agency publishes the notice of availability in the **Federal Register**.

The Forest Service believes, at this early stage, it is important to give reviewers notice of several court rulings related to public participation in the environmental review process. First, reviewers of draft environmental impact statements 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 but that are not raised until after completion of the final environmental impact statement 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, 1338 (E.D. Wis. 1980). Because of these court rulings, it is very important and those interested in the 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 them 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 statement. 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: January 20. 2004.

Charlie Marsh,

District Ranger.

[FR Doc. 04–1988 Filed 1–29–04; 8:45 am]

BILLING CODE 3410–CA–M

DEPARTMENT OF AGRICULTURE

Forest Service

Alpine County, CA, Resource Advisory Committee (RAC)

AGENCY: Forest Service, USDA.

ACTION: Notice of meeting.

SUMMARY: Pursuant to the authorities in the Federal Advisory Committees Act (Pub. L. 92–463) and under the Secure Rural Schools and Community Self-Determination Act of 2000 (Pub. L. 106–393) the Alpine County Resource Advisory Committee (RAC) will meet on Monday, February 2, 2004, at 18:00 at the Diamond Valley School for business meetings. The purpose of the meeting is to discuss issues relating to implementing the Secure Rural Schools and Community Self-Determination Act of 2000 (Payment to States) and expenditure of Title II funds. The meetings are open to the public.

DATES: Monday, February 2, 2004, at 18:00 hours.

ADDRESSES: The meeting will be held at the Diamond Valley School (physical address, room and time). Send written comments to Franklin Pemberton, Alpine County RAC coordinator, c/o USDA Forest Service, Humboldt-Toiyabe N.F., Carson Ranger District 1536 So. Carson Street, Carson City, NV 89701.

FOR FURTHER INFORMATION CONTACT: Alpine Co. RAC Coordinator, Franklin Pemberton at (775) 884–8150; or Gary Schiff, Carson District Ranger and Designated Federal Officer, at (775) 884–8100, or electronically to *fpemberton@fs.fed.us*.

SUPPLEMENTARY INFORMATION: The Meeting is open to the public. Council discussion is limited to Forest Service staff and Council members. However, persons who wish to bring urban and community forestry matters to the attention of the council may file written statements with the Council staff before and after the meeting.

Dated: January 22, 2004.

Larry Randall,

Acting Carson District Ranger.

[FR Doc. 04–1904 Filed 1–29–04; 8:45 am]

BILLING CODE 3410–11–M

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 Procurement List.

SUMMARY: This action adds to the Procurement List services to be furnished by nonprofit agencies employing persons who are blind or have other severe disabilities, and deletes from the Procurement List products previously furnished by such agencies.

EFFECTIVE DATE: February 29, 2004.

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: Sheryl D. Kennerly, (703) 603–7740.

SUPPLEMENTARY INFORMATION:

Additions

On November 7 and December 5, 2003, the Committee for Purchase From People Who Are Blind or Severely Disabled published notice (68 F.R. 63057 and 68023) of proposed additions to the Procurement List.

After consideration of the material presented to it concerning capability of qualified nonprofit agencies to provide the services and impact of the additions on the current or most recent contractors, the Committee has determined that the 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 services to the Government.

2. The action will 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 added to the Procurement List.

End of Certification

Accordingly, the following services are added to the Procurement List:

Services

Service Type/Location: Custodial Services, VA Community Based Outpatient Clinic North Shore, Lynn, Massachusetts and VA Community Based Outpatient Clinic, Haverill, Massachusetts.

NPA: Morgan Memorial Goodwill Industries, Boston, Massachusetts

Contract Activity: VA Medical Center—Edith Nourse Rogers Memorial, Bedford, Massachusetts

Service Type/Location: Document Destruction

At the following Locations and for the Nonprofit Agencies Indicated: Camarillo Office, IRS (Including the Criminal Investigation Division), 751 Daily Drive, Camarillo, California

NPA: Goodwill Industries of Southern California, Los Angeles, CA, El Centro Office, IRS, 1699 W. Main Street, El Centro, California

NPA: Landmark Services, Inc., Santa Ana, California, El Monte Office, IRS (Including the Criminal Investigation Division), 9350 E. Flair Drive, El Monte, California

NPA: Goodwill Industries of Southern California, Los Angeles, California, El Segundo Office, IRS (Including the Criminal Investigation, Division), 222 N. Sepulveda Blvd., El Segundo, California

NPA: Goodwill Industries of Southern California, Los Angeles, California, Glendale Office, IRS (Including the Criminal Investigation Division), 225 W. Broadway, Glendale, California

NPA: Goodwill Industries of Southern California, Los Angeles, California, Laguna Niguel Office, IRS (Including the Criminal Investigation Division), 24000 Avila Road, Laguna Niguel, California

NPA: Landmark Services, Inc., Santa Ana, California, Long Beach Office, IRS (Including the Criminal Investigation Division), 501 W. Ocean Blvd., Long Beach, California

NPA: Landmark Services, Inc., Santa Ana, California, Los Angeles Office, IRS (Including the Criminal Investigation Division), 300 N. Los Angeles Street, Los Angeles, California

NPA: Goodwill Industries of Southern California, Los Angeles, California, Norwalk Office, IRS, 12440 E. Imperial Highway, Norwalk, California

NPA: Goodwill Industries of Southern California, Los Angeles, California, Palm Springs Office, IRS, 980 E. Tahquitz Canyon Way, Palm Springs, California

NPA: Goodwill Industries of Southern California, Los Angeles, California, San Bernardino Office, IRS (Including the Criminal Investigation Division), 290 N. "D" Street, San Bernardino, California

NPA: Goodwill Industries of Southern California, Los Angeles, California, San Diego Office, IRS (Including the Criminal Investigation Division), 880 Front Street, and 701 "B" Street, San Diego, California

NPA: Landmark Services, Inc., Santa Ana, California, San Marcos Office, IRS, 1 Civic Center Drive, San Marcos, California

NPA: Landmark Services, Inc., Santa Ana, California, Santa Ana Office, IRS (Including the Criminal Investigation Division), 34 Civic Center Plaza, Santa Ana, California

NPA: Landmark Services, Inc., Santa Ana, California, Van Nuys Office, IRS (Including the Criminal Investigation Division), 6230 Van Nuys Blvd., Van Nuys, California

NPA: Goodwill Industries of Southern California, Los Angeles, California, Woodland Hills Office, IRS, 6340 Variel Ave, Woodlands Hills, California

NPA: Goodwill Industries of Southern California, Los Angeles, California

Contract Activity: IRS-Western Area Procurement Branch-APFW, San Francisco, California

Service Type/Location: Mailing Services, Theodore Levin U.S. Courthouse, U.S. District Court, Eastern District of Michigan, Detroit, Michigan

NPA: Jewish Vocational Service and Community Workshop, Southfield, Michigan

Contract Activity: U.S. District Court, Detroit, Michigan

Deletions

On December 5, 2003 the Committee for Purchase From People Who Are Blind or Severely Disabled published notice (68 FR 68024) of proposed deletions to the Procurement List. After consideration of the relevant matter presented, the Committee has determined that the products 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 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 deleted from the Procurement List.

End of Certification

Accordingly, the following products are deleted from the Procurement List:

Products

Product/NSN: Detergent, General Purpose/ 7930–01–055–6121
NPA: Lighthouse for the Blind, St. Louis, MO
Contract Activity: GSA, Southwest Supply Center, Fort Worth, TX
Product/NSN: Holder, Desk Memorandum, 7520–00–139–3802
7520–00–290–6445
NPA: Dallas Lighthouse for the Blind, Inc., Dallas, TX
Contract Activity: Office Supplies & Paper Products Acquisition Ctr, New York, NY
Product/NSN: Sponge, Cellulose/7920–00–559–8462
NPA: Mississippi Industries for the Blind, Jackson, MS
Contract Activity: GSA, Southwest Supply Center, Fort Worth, TX
Product/NSN: Strap Set, Webbing/5342–00–922–2480
NPA: Huntsville Rehabilitation Foundation, Huntsville, AL
Contract Activity: Defense Supply Center Richmond, Richmond, VA

Sheryl D. Kennerly,
Director, Information Management.
[FR Doc. 04–1992 Filed 1–29–04; 8:45 am]
BILLING CODE 6353–01–P

COMMITTEE FOR PURCHASE FROM PEOPLE WHO ARE BLIND OR SEVERELY DISABLED

Redesignation of Services; Correction

In the document appearing on page 2565, FR Doc 04–1029, in the issue of January 16, 2004, in the first and second columns, the Committee published a redesignation of services currently on the Procurement List for Janitorial/ Custodial, Johnstown, Pennsylvania. The name of the Nonprofit Agency associated with this redesignation was misspelled. It should read Goodwill Industries of the Conemaugh Valley, Inc., Johnstown, Pennsylvania.

Sheryl D. Kennerly,
Director, Information Management.
[FR Doc. 04–1993 Filed 1–29–04; 8:45 am]
BILLING CODE 6353–01–P

DEPARTMENT OF COMMERCE

Bureau of the Census

[Docket Number 030829216–4023–02]

RIN 0607–AA40

Annual Trade Survey

AGENCY: Bureau of the Census, Commerce.

ACTION: Notice.

SUMMARY: The Bureau of the Census (Census Bureau) is expanding the 2003 Annual Trade Survey (ATS) to include manufacturers' sales branches and offices (MSBO). The Census Bureau makes this expansion at the request of the Bureau of Economic Analysis (BEA). The BEA considers this information vital to its accurate measurement of sales and inventories for wholesale trade. These data are important inputs to BEA's preparation of National Income and Product accounts and its annual input-output tables.

DATES: The Census Bureau adopts the expanded ATS as of January 30, 2004.

FOR FURTHER INFORMATION CONTACT: John Trimble, Chief, Annual Trade and Special Projects Branch, Service Sector Statistics Division, at (301) 763–7223 or by e-mail at *John Trimble@census.gov.*

SUPPLEMENTARY INFORMATION: The Census Bureau is authorized to take surveys necessary to furnish current data on the subjects covered by the major censuses authorized by Title 13, United States Code (U.S.C.), sections 182, 224, and 225. The expanded ATS will provide continuing and timely national statistical data on MSBO for the period between the five year economic censuses. These data ensure a sound statistical basis for the formation of policy by various government agencies. They also apply to a variety of public and business needs. These data are not available publicly on a timely basis from nongovernmental or other governmental sources.

On September 15, 2003 (68 FR 53959), the Census Bureau published in the **Federal Register** a notice and request for comment on the expansion of the ATS. We did not receive any comments on that notice. Accordingly, the Census Bureau is adopting without change, its proposal to include manufacturers' sales and offices in the 2003 Annual Trade Survey.

The previous ATS collected data only for merchant wholesalers. This new, expanded survey includes a selected sample of firms and operating establishments primarily selling goods that they manufacture in the United States. These data will be a vital source for accurately measuring sales, inventories, and operating expenses for wholesale trade. The BEA has made repeated requests for this information. The expanded ATS covers approximately 90 percent of sales from the wholesale sector and over 99 percent of its inventories compared to about 58 percent of sales and 85 percent of inventories in the previous ATS sample.

Beginning with the survey year 2003, the goal is to maximize industry coverage within our available resources. In order to establish reporting arrangements and reduce respondent burden, we will mail report forms to a sample of firms on a company basis and contact them in person, as well as by phone and mail. We will mail a survey introduction letter followed by report forms to the firms covered by this survey and require the report forms to be returned thirty days after receipt. The report forms will request similar data items, but different forms are needed to accommodate both merchant wholesale and MSBO companies, as well as both large and small firms. Later, as necessary, additional mail follow-ups and telephone follow-ups will be conducted.

The primary users of these data will be federal, state, and local government agencies, including the Census Bureau, BEA, and Environmental Protection Agency. Other users will include business firms, academics, trade associations, and research and consulting organizations.

Rulemaking Requirements

Executive Order 12866

This rule has been determined to be not significant for purposes of Executive Order 12866.

Regulatory Flexibility Act

The Chief Counsel for Regulation of the Department of Commerce certified to the Chief Counsel for Advocacy of the Small Business Administration that this rule would not have a significant economic impact on a substantial number of small entities. The factual basis for this certification was published in the proposed rule. No comments were received regarding the economic impact of this rule. As a result, no final regulatory flexibility analysis was prepared.

Paperwork Reduction Act

Notwithstanding any other provision of law, no person is required to respond to, nor shall a person be subject to a penalty for failure to comply with, a collection of information subject to requirements of the Paperwork Reduction Act (PRA), unless that collection of information displays a current, valid Office of Management and Budget (OMB) control number. In accordance with the PRA (44 U.S.C. 3501 *et seq.*), OMB approved on January 9, 2004, with control number 0607–0195, the collection of all information associated with this rule. We estimate the number of additional respondents to be 1,600 and estimate an additional 713 annual burden hours with this expanded data collection. Also, we estimate that the time for the additional responses associated with this data collection will be approximately 27 minutes. We will furnish report forms to organizations included in the survey, and additional copies will be available on written request to the Director, U.S. Census Bureau, Washington, DC 20233–0101.

Dated: January 26, 2004.

Charles Louis Kincannon,

Director, Bureau of the Census.

[FR Doc. 04–1979 Filed 1–29–04; 8:45 am]

BILLING CODE 3510–07–P

DEPARTMENT OF COMMERCE

Bureau of Industry and Security

Transportation and Related Equipment Technical Advisory Committee; Notice of Open Meeting

The Transportation and Related Equipment Technical Advisory Committee will meet on February 17, 2004, 9:30 a.m., at the Herbert C. Hoover Building, Room 3884, 14th Street between Pennsylvania & Constitution Avenues, NW., Washington, DC. The Committee advises the Office of the Assistant Secretary for Export Administration with respect to technical questions which affect the level of export controls applicable to transportation and related equipment or technology.

Agenda

1. Opening remarks and introductions.
2. Review of Wassenaar Arrangement and Technical Working Group issues.
4. Review of Missile Technology Control Regime issues.
5. Update on Export Administration Regulations.
6. Update on status of US Munitions List.
7. Update on status of current TransTAC proposals.
8. Discussion of Commerce Control List entries needing review for revalidation or change proposals.
9. Presentation of papers, proposals and comments by the public.

The meeting will be open to the public and a limited number of seats will be available. Reservations are not accepted. To the extent time permits, members of the public may present oral statements to the Committee. Written statements may be submitted at any time before or after the meeting. However, to facilitate distribution of public presentation materials to Committee members, the Committee suggests that you forward your public presentation materials two weeks prior to the meeting to the following address: Ms. Lee Ann Carpenter, BIS/EA MS: 1099D, U.S. Department of Commerce, 14th & Constitution Avenue, NW., Washington, DC 20230.

For more information call Lee Ann Carpenter on (202) 482–2583.

Dated: January 27, 2004.

Lee Ann Carpenter,

Committee Liaison Officer.

[FR Doc. 04–1990 Filed 1–29–04; 8:45 am]

BILLING CODE 3510–JT–M

DEPARTMENT OF COMMERCE

International Trade Administration

[A–570–867]

Notice of Extension of Time Limit for the Preliminary Results of the Antidumping Duty Administrative Review: Certain Automotive Replacement Glass Windshields From the People's Republic of China

AGENCY: Import Administration, International Trade Administration, Department of Commerce.

ACTION: Notice of extension of time limit for the preliminary results of antidumping duty administrative review of Certain Automotive Replacement Glass Windshields from China.

SUMMARY: The Department of Commerce ("the Department") is extending the time limit for the preliminary results of the antidumping duty review of automotive replacement glass windshields from the People's Republic of China. This review covers the period September 19, 2001 through March 31, 2003.

EFFECTIVE DATE: January 30, 2004.

FOR FURTHER INFORMATION CONTACT: Robert Bolling or Jonathan Herzog, AD/CVD Enforcement, Group III, Office 9, Import Administration, International Trade Administration, U.S. Department of Commerce, 14th Street and Constitution Avenue NW., Washington DC 20230; telephone: (202) 482–3434 and (202) 482–4271, respectively.

Background

On April 7, 2003, the Department published a notice of opportunity to request an administrative review of the antidumping duty order on automotive replacement glass windshields ("ARG") from the People's Republic of China ("PRC") for the period September 19, 2001 through March 31, 2003. *See Antidumping or Countervailing Duty Order, Finding, or Suspended Investigation: Opportunity to Request Administrative Review*, 68 FR 16761 (April 7, 2003). On April 15, 2003, Dongguan Kongwan Automobile Glass Limited and Peaceful City Limited, requested an administrative review of their sales to the United States during the period of review ("POR"). On April 21, 2003, an importer, Pilkington North America requested an administrative review of the sales of Changchun Pilkington Safety Glass Company Limited, Guilin Pilkington Safety Glass Company Limited, Shanghai Yaohua Pilkington Autoglass Company Limited, and Wuhan Yaohua Pilkington Safety Glass Company Limited to the United States during the POR. On April 22, 2003, TCG International Inc. ("TCGI"), requested an administrative review of its sales to the United States during the POR. On April 30, 2003, Xinyi Automotive Glass (Shenzhen) Company, Limited ("Xinyi"), Shenzhen CSG Automotive Glass Company, Limited (reported to be the former company Shenzhen Benxun Auto Glass Company, Limited) ("Benxun"), and Fuyao Glass Industry Group Company, Limited requested an administrative review of their sales to the United States during the POR. On May 21, 2003, the Department published in the **Federal Register** a notice of the initiation of the antidumping duty administrative review of ARG from the PRC for the period September 19, 2001 through March 31, 2003. *See Initiation of Antidumping and Countervailing Duty Administrative Reviews and Request for Revocation in Part*, 68 FR 27781 (May 21, 2003). On September 8, 2003, the Department published a notice in the **Federal Register** rescinding the administrative reviews of TCGI, Xinyi, and Benxun.[1] *See Certain Automotive Replacement Glass Windshields from the People's Republic of China: Notice of Partial Rescission of the Antidumping Duty Administrative Review*, 68 FR 52893 (September 8, 2003). On October 24, 2003, the Department published a notice in the **Federal Register** extending the time limit for the preliminary results of review by 60 days. *See Certain Automotive Replacement Glass Windshields from the People's Republic of China: Extension of Time Limit for Preliminary Results of Antidumping Duty Administrative Review*, 68 FR 60911 (October 24, 2003). The preliminary results of review are currently due no later than February 29, 2004.

[1] Because Bexun withdrew its request for review, the Department did not have the information necessary to make a successor-in-interest determination. Therefore the Department did not determine that Shenzhen CSG Automotive Glass

Extension of Time Limit of Preliminary Results

Section 751(a)(3)(A) of the Tariff Act of 1930, as amended ("the Act"), states that if it is not practicable to complete the review within the time specified, the administering authority may extend the statutory time limit of 245 days to issue its preliminary results by up to 120 days. Completion of the preliminary results of this review within the 245-day period is not practicable for the following reasons: (1) the review involves several complicated issues, such as affiliation, which require the Department to gather and analyze a significant amount of information pertaining to each company's sales practices, factors of production, and corporate relationships; and (2) due to the Chinese New Year, the Department has delayed the planned verification schedules and, therefore, will not have sufficient time to complete its preliminary results by the scheduled deadline of February 29, 2004.

Because it is not practicable to complete this review within the time specified under the Act, we are extending the time period for issuing the preliminary results of review by 60 days until April 29, 2004, in accordance with section 751(a)(3)(A) of the Act. The final results continue to be due 120 days after the publication of the preliminary results.

Dated: January 26, 2004.

Richard O. Weible,

Acting Deputy Assistant Secretary for Import Administration, Group III.

[FR Doc. 04–1987 Filed 1–29–04; 8:45 am]

BILLING CODE 3510–DS–P

DEPARTMENT OF COMMERCE

International Trade Administration

[C–122–839]

Certain Softwood Lumber Products from Canada: Final Results of Countervailing Duty New Shipper Review

AGENCY: Import Administration, International Trade Administration, Department of Commerce.

ACTION: Notice of Final Results of Countervailing Duty New Shipper Review.

SUMMARY: On October 31, 2003, the Department of Commerce (the Department) published in the **Federal Register** the preliminary results of the countervailing duty (CVD) new shipper review in Certain Softwood Lumber Products from Canada. *See Certain Softwood Lumber Products from Canada: Preliminary Results of New Shipper Countervailing Duty Review*, 68 FR 62055 (October 31, 2003) *(Preliminary Results)*.

The net subsidy rate in this *Final Results* does not differ from that indicated in the *Preliminary Results*. The final net subsidy rate for the reviewed company is listed below in the "Suspension of Liquidation" section of this notice.

EFFECTIVE DATE: January 30, 2004.

FOR FURTHER INFORMATION CONTACT: Jonathan McKernan at (202) 482–5973, Office of AD/CVD Enforcement VI, Group II, Import Administration, International Trade Administration, U.S. Department of Commerce, Room 4012, 14th Street and Constitution Avenue NW., Washington, DC 20230.

SUPPLEMENTARY INFORMATION

Background

On October 31, 2003, the Department published the *Preliminary Results* in the **Federal Register**. On December 9, 2003, the Department conducted verification of the questionnaire responses submitted by La Pointe & Roy Ltee. (La Pointe & Roy), the sole respondent subject to the new shipper review.

In accordance with 19 CFR 351.214(a), this new shipper review covers only those producers or exporters for which a review was specifically requested. Accordingly, this new shipper review covers subject merchandise produced and exported by La Pointe & Roy.

Scope of the Review

The products covered by this order are softwood lumber, flooring and siding (softwood lumber products). Softwood lumber products include all products classified under headings 4407.1000, 4409.1010, 4409.1090, and 4409.1020, respectively, of the Harmonized Tariff Schedule of the United States (HTSUS), and any softwood lumber, flooring and siding described below. These softwood lumber products include:

(1) Coniferous wood, sawn or chipped lengthwise, sliced or peeled, whether or not planed, sanded or finger-jointed, of a thickness exceeding six millimeters;

(2) Coniferous wood siding (including strips and friezes for parquet flooring, not assembled) continuously shaped (tongued, grooved, rabbeted, chamfered, v-jointed, beaded, molded, rounded or the like) along any of its edges or faces, whether or not planed, sanded or finger-jointed;

(3) Other coniferous wood (including strips and friezes for parquet flooring, not assembled) continuously shaped (tongued, grooved, rabbeted, chamfered, v-jointed, beaded, molded, rounded or the like) along any of its edges or faces (other than wood moldings and wood dowel rods) whether or not planed, sanded or finger-jointed; and

(4) Coniferous wood flooring (including strips and friezes for parquet flooring, not assembled) continuously shaped (tongued, grooved, rabbeted, chamfered, v-jointed, beaded, molded, rounded or the like) along any of its edges or faces, whether or not planed, sanded or finger-jointed.

Although the HTSUS subheadings are provided for convenience and customs purposes, the written description of the merchandise subject to this order is dispositive.

As specifically stated in the Issues and Decision Memorandum accompanying the Notice *of Final Determination of Sales at Less Than Fair Value: Certain Softwood Lumber Products from Canada* (67 FR 15539; April 2, 2002) (*see* comment 53, item D, page 116, and comment 57, item B–7, page 126), available at *http://www.ia.ita.doc.gov,* drilled and notched lumber and angle cut lumber are covered by the scope of this order.

The following softwood lumber products are excluded from the scope of this order provided they meet the specified requirements detailed below:

(1) *Stringers* (pallet components used for runners): if they have at least two notches on the side, positioned at equal distance from the center, to properly accommodate forklift blades, properly classified under HTSUS 4421.90.98.40.

(2) *Box-spring frame kits:* if they contain the following wooden pieces—two side rails, two end (or top) rails and varying numbers of slats. The side rails and the end rails should be radius-cut at both ends. The kits should be individually packaged, they should contain the exact number of wooden components needed to make a particular box spring frame, with no further processing required. None of the components exceeds 1″ in actual thickness or 83″ in length.

(3) *Radius-cut box-spring-frame components,* not exceeding 1″ in actual thickness or 83″ in length, ready for assembly without further processing. The radius cuts must be present on both ends of the boards and must be substantial cuts so as to completely round one corner.

(4) *Fence pickets* requiring no further processing and properly classified under HTSUS heading 4421.90.70, 1″ or less in actual thickness, up to 8″ wide,

---

Company, Limited is entitled to receive the same antidumping cash deposit rate accorded Benxun.

6′ or less in length, and have finials or decorative cuttings that clearly identify them as fence pickets. In the case of dog-eared fence pickets, the corners of the boards should be cut off so as to remove pieces of wood in the shape of isosceles right angle triangles with sides measuring 3/4 inch or more.

(5) *U.S. origin lumber* shipped to Canada for minor processing and imported into the United States, is excluded from the scope of this order if the following conditions are met: (1) The processing occurring in Canada is limited to kiln-drying, planing to create smooth-to-size board, and sanding, and (2) if the importer establishes to the Bureau of Customs and Border Protection's (CBP) satisfaction that the lumber is of U.S. origin.

(6) *Softwood lumber products contained in single family home packages or kits,*[1] regardless of tariff classification, are excluded from the scope of this order if the importer certifies to items 6 A, B, C, D, and requirement 6 E is met:

A. The imported home package or kit constitutes a full package of the number of wooden pieces specified in the plan, design or blueprint necessary to produce a home of at least 700 square feet produced to a specified plan, design or blueprint;

B. The package or kit must contain all necessary internal and external doors and windows, nails, screws, glue, sub floor, sheathing, beams, posts, connectors, and if included in the purchase contract, decking, trim, drywall and roof shingles specified in the plan, design or blueprint.

C. Prior to importation, the package or kit must be sold to a retailer of complete home packages or kits pursuant to a valid purchase contract referencing the particular home design plan or blueprint, and signed by a customer not affiliated with the importer;

D. Softwood lumber products entered as part of a single family home package or kit, whether in a single entry or multiple entries on multiple days, will be used solely for the construction of the single family home specified by the home design matching the entry.

E. For each entry, the following documentation must be retained by the importer and made available to the CBP upon request:

i. A copy of the appropriate home design, plan, or blueprint matching the entry;

ii. A purchase contract from a retailer of home kits or packages signed by a customer not affiliated with the importer;

iii. A listing of inventory of all parts of the package or kit being entered that conforms to the home design package being entered;

iv. In the case of multiple shipments on the same contract, all items listed in E(iii) which are included in the present shipment shall be identified as well.

Lumber products that the CBP may classify as stringers, radius cut box-spring-frame components, and fence pickets, not conforming to the above requirements, as well as truss components, pallet components, and door and window frame parts, are covered under the scope of this order and may be classified under HTSUS subheadings 4418.90.45.90, 4421.90.70.40, and 4421.90.97.40.

Finally, as clarified throughout the course of the investigation, the following products, previously identified as Group A, remain outside the scope of this order. They are:

1. Trusses and truss kits, properly classified under HTSUS 4418.90;
2. I-joist beams;
3. Assembled box spring frames;
4. Pallets and pallet kits, properly classified under HTSUS 4415.20;
5. Garage doors;
6. Edge-glued wood, properly classified under HTSUS item 4421.90.98.40;
7. Properly classified complete door frames;
8. Properly classified complete window frames;
9. Properly classified furniture.

In addition, this scope language has been further clarified to now specify that all softwood lumber products entered from Canada claiming non-subject status based on U.S. country of origin will be treated as non-subject U.S.-origin merchandise under the countervailing duty order, provided that these softwood lumber products meet the following condition: upon entry, the importer, exporter, Canadian processor and/or original U.S. producer establish to CBP's satisfaction that the softwood lumber entered and documented as U.S.-origin softwood lumber was first produced in the United States as a lumber product satisfying the physical parameters of the softwood lumber scope.[2] The presumption of non-subject status can, however, be rebutted by evidence demonstrating that the merchandise was substantially transformed in Canada.

Analysis of Comments Received

We received no comments from interested parties regarding our *Preliminary Results.*

A description of our calculation of the net subsidy rate is addressed in the "Issues and Decision Memorandum" (Decision Memorandum) dated January 22, 2004, which is hereby adopted by this notice. Attached to this notice is Appendix I, which contains an outline of the Decision Memorandum. Parties can find a complete copy of the Decision Memorandum, a public document, in room B–099 of the Main Commerce Building. In addition, a complete version of the Decision Memorandum can be accessed directly on the World Wide Web at *http://www.ia.ita.doc.gov,* under the heading "**Federal Register** Notices." The paper copy and electronic version of the Decision Memorandum are identical in content.

Suspension of Liquidation

In accordance with 19 CFR 351.214(a), we have calculated an individual rate for La Pointe & Roy. We determine the net subsidy rate for La Pointe & Roy to be as follows:

Producer/Exporter	Net subsidy rate
La Pointe & Roy Ltee.	.0.08 percent *ad valorem.*

As provided for in 19 CFR 351.106(c)(1), any rate less than 0.5 percent *ad valorem* in a new shipper review is *de minimis.* Accordingly, no countervailing duties will be assessed on La Pointe & Roy. The Department will instruct the CBP to liquidate, without regard to countervailing duties, shipments of the subject merchandise produced and exported by La Pointe & Roy that were entered, or withdrawn from warehouse, for consumption on or after May 22, 2002, the date on which entries of subject merchandise were suspended under this order, and on or before December 31, 2002. In addition, the cash deposit rate for this company will be set at zero, prospectively.

Return or Destruction of Proprietary Information

This notice will serve as the only reminder to parties subject to Administrative Protective Order (APO)

---

[1] To ensure administrability, we clarified the language of exclusion number 6 to require an importer certification and to permit single or multiple entries on multiple days as well as instructing importers to retain and make available for inspection specific documentation in support of each entry.

[2] *See* the scope clarification message (# 3034202), dated February 3, 2003, to the CBP, regarding treatment of U.S. origin lumber on file in the Central Records Unit, Room B–099 of the main Commerce Building.

of their responsibility concerning the destruction of proprietary information disclosed under APO in accordance with 19 CFR 351.305(a)(3). Failure to comply is a violation of the APO.

This determination is published pursuant to section 777(i) of the Act.

Dated: January 22, 2004.

James J. Jochum,

Assistant Secretary for Import Administration.

Appendix I—Issues and Decision Memorandum

Analysis of Programs

I. Programs Determined to Be Countervailable
A. Private Forest Development Program (PFDF)
II. Programs Determined to Be Not Used
A. Provincial Stumpage Program
B. Export Assistance under the Societe de Developpement Industrial du Quebec (SDI)/Investissement Quebec (IQ)
C. Assistance under Articles 7 and 28 of the SDI
D. Assistance from the Societe de Recuperation d'Exploitation et de Developpement Forestiers du Quebec (Rexfor)
III. Total Ad Valorem Rate
IV. Recommendation

[FR Doc. 04–1989 Filed 1–29–04; 8:45 am]

BILLING CODE 3510–DS–P

DEPARTMENT OF COMMERCE

International Trade Administration

United States Travel and Tourism Promotion Advisory Board

AGENCY: International Trade Administration, Department of Commerce.

ACTION: Notice of open meeting.

Date: February 11, 2004.

Time: 10 a.m.–12 p.m .

Place: Loews L'Enfant Plaza Hotel, 480 L'Enfant Plaza East, Washington, DC 20001.

SUMMARY: The United States Travel and Tourism Promotion Advisory Board ("Board") will hold a Board meeting on February 11, 2004 at the Loews L'Enfant Plaza Hotel.

The Board will discuss the design, development and subsequent implementation of an international advertising and promotional campaign, which will seek to encourage individuals from select countries to travel to the United States for the express purpose of engaging in tourism. The meeting will be open to the public. Time will be permitted for public comment. To sign up for public comment, please contact Julie Heizer by 5 p.m. EST Monday, February 9, 2004. She may be contacted at U.S. Department of Commerce, 1401 Constitution Avenue, NW., Room 7025, Washington, DC 20230; via fax at (202) 482–2887; or, via e-mail at *promotion@tinet.ita.doc.gov.*

Written comments concerning Board affairs are welcome anytime before or after the meeting. Written comments should be directed to Julie Heizer. Minutes will be available within 30 days of this meeting.

The Board is mandated by Public Law 108–7, Section 210. As directed by Public Law 108–7, Section 210, the Secretary of Commerce shall design, develop and implement an international advertising and promotional campaign, which seeks to encourage individuals to travel to the United States. The Board shall recommend to the Secretary of Commerce the appropriate coordinated activities for funding. This campaign shall be a multi-media effort that seeks to leverage the Federal dollars with contributions of cash and in-kind products unique to the travel and tourism industry. The Board was chartered in August of 2003 and will expire on August 8, 2005.

FOR FURTHER INFORMATION CONTACT: Julie Heizer, Office of Travel and Tourism Industries (OTTI), International Trade Administration, U.S. Department of Commerce at (202) 482–4904. This meeting is physically accessible to people with disabilities. Requests for sign language interpretation or other auxiliary aids should be directed to OTTI.

Dated: January 16, 2004.

Julie Heizer,

Deputy Director for Industry Relations, Office of Travel and Tourism Industries.

[FR Doc. 04–1980 Filed 1–29–04; 8:45 am]

BILLING CODE 3510–25–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

[Docket No. 040114019–4019–01; I.D. 121903C]

Endangered and Threatened Wildlife and Plants; 90–Day Finding for a Petition to List Winter Flounder and Cunner as Threatened or Endangered

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

ACTION: Notice of petition finding.

SUMMARY: NMFS has received a petition to add winter flounder (*Pseudopleuronectes americanus*) and cunner (*Tautogolabrus adspersus*) from western Long Island Sound to the list of threatened and endangered wildlife under the Endangered Species Act (ESA) of 1973, as amended. NMFS has determined that the petition does not present substantial scientific or commercial information indicating that the petitioned action may be warranted at this time.

DATES: This finding becomes effective on March 1, 2004.

ADDRESSES: Comments or questions concerning this petition finding should be sent to Mary Colligan, NMFS, Protected Resources Division, One Blackburn Drive, Gloucester, MA 01930.

FOR FURTHER INFORMATION CONTACT: Kim Damon-Randall, NMFS Northeast Region, 978–281–9328 ext. 6535, or Marta Nammack, NMFS Office of Protected Resources, 301–713–1401, ext. 180.

SUPPLEMENTARY INFORMATION:

Background and Analysis of Petition

Under Section 4(b)(3)(A) of the ESA, to the maximum extent practicable, within 90 days after receiving a petition to list a species under the ESA, the Secretary of Commerce (Secretary) must make a finding whether the petition presents substantial scientific or commercial information indicating that the petitioned action may be warranted. This finding must be promptly published in the **Federal Register**. In determining whether a petition contains substantial information, NMFS takes into account information submitted with and referenced in the petition and all other information readily available in NMFS' files. NMFS' ESA implementing regulations at 50 CFR 424.14(b)(1) define "substantial information" as the amount of information that would lead a reasonable person to believe that the measure proposed in the petition may be warranted. If the petition is found to present such information, the Secretary must conduct a status review of the involved species and make a determination whether the petitioned action is warranted within 12 months of receipt of the petition. In making a finding on a petition to list a species, the Secretary must consider whether such a petition (i) clearly indicates the administrative measure recommended and gives the scientific and any common name of the species involved; (ii) contains detailed narrative justification for the recommended measure, describing, based on available information, past and present numbers and distribution of the species involved and any threats faced by the species;

(iii) provides information regarding the status of the species over all or a significant portion of its range; and (iv) is accompanied by the appropriate supporting documentation in the form of bibliographic references, reprints of pertinent publications, copies of reports or letters from authorities, and maps (50 CFR 424.14(b)(2)).

On May 27, 2003, the Assistant Administrator received a petition dated May 15, 2003, from Arthur Glowka to list the western Long Island Sound populations of winter flounder and cunner as endangered or threatened under the ESA. The information contained in the petition focuses on the results of the Environmental Protection Agency's (EPA) efforts to restore water quality in the Sound. It is the petitioner's contention that EPA's efforts to reduce nutrient loading through the implementation of Total Maximum Daily Loads (TMDL) for various pollutants has starved the plankton in the Sound, thereby affecting the entire food web and resulting in declines in the number, size, and robustness of many sport fish.

Under the ESA, a listing determination can address a species, subspecies, or distinct population segment (DPS) of a species (16 U.S.C. 1532(15)). A DPS is, in short, a vertebrate population that is discrete in relation to the remainder of the species to which it belongs and significant to the species to which it belongs (61 FR 4722; February 7, 1996). The petitioner requested listing both winter flounder and cunner from western Long Island Sound only. The petitioner states, "we feel that the population of winter flounder and cunner in western Long Island Sound have decreased to such low numbers that they may never recover and are good candidates for endangered/threatened status." The information contained in the petition focuses on impacts to these species that occur in the western portion of the Sound. As such, NMFS first attempted to identify the boundary or boundaries of the population that includes the fish from western Long Island Sound and assess whether available information indicated that the population may warrant listing under the ESA.

NMFS evaluated whether the information provided or cited in the petition met the ESA's standard for "substantial information." We reviewed information that is readily available to NMFS scientists and consulted fisheries experts from the state of Connecticut to determine whether the petitioned action may be warranted and if available information supports the identification of DPSs for these species in western Long Island Sound.

Cunner

Cunner are widespread along the Atlantic coast and offshore banks of North America, from the eastern coast of Northern Newfoundland, southward in abundance to New Jersey, and as far south as the mouth of the Chesapeake Bay (Collette and Klein-MacPhee 2002). While the petitioner presents some anecdotal evidence which suggests that there may have been a decline in the number of cunner in Long Island Sound, there is not sufficient scientific or commercial information available to support the petition. There is little to no information available about the population structure and genetics of the species. As such, NMFS finds that the petition does not present substantial scientific or commercial information indicating that listing of cunner in western Long Island Sound may be warranted.

Winter Flounder

Winter flounder are managed federally as three separate stocks the Gulf of Maine, southern New England/ Middle Atlantic, and Georges Bank. The petitioner defines western Long Island Sound as "a line drawn north to south from Norwalk, CT to Eaton's Neck, Long Island, NY and the waters which lie to the west to the Throgs Neck Bridge in New York City." Winter flounder from this area are currently included in the southern New England/Middle Atlantic stock.

Genetic, morphometric, and life history information support these broad-scale divisions. Dr. Isaac Wirgin from the Nelson Institute of Environmental Medicine, New York University School of Medicine, used microsatellite analysis of nuclear DNA in an attempt to verify that these stock divisions were appropriate (Wirgin 2003). According to Wirgin (2003), the overall results showed that stocks south of Cape Cod were usually genetically distinct from the stock at Georges Bank. Two of the three areas sampled north of Cape Cod exhibited significant genetic differences from fish sampled from Georges Bank. Therefore, preliminary evidence suggests genetic discreteness for fish from the Gulf of Maine, Georges Bank, and Southern New England/Middle Atlantic regions. Also, according to Collette and Klein-MacPhee (2002), winter flounder may be separated into different local races based on varying characteristics such as fin ray counts and maximum size. Fish from Georges Bank have been documented to have a greater number of dorsal and anal fin rays, larger maximum sizes, different coloration, and different spawning seasons as fish from other parts of this species' range. The best available information supports the broad scale stock divisions currently employed by Federal fishery managers.

Available data also indicate the possibility of smaller divisions within the New England/Middle Atlantic stock. Most, but not all, collections that were taken south of Cape Cod were genetically distinct from those sampled in nearby areas to the south and north (Wirgin 2003). According to Dr. Wirgin (2003), collections from Peconic Bay, NY were significantly different from samples taken in Mt. Hope Bay, RI, and Jamaica Bay, NY. Highly significant genetic differences were also found among many, but not all, estuaries south of Cape Cod. In many cases, significant differences were found between geographically adjacent collections.

However, no significant differences were found among the three estuaries sampled in Long Island Sound the Connecticut River, New Haven Harbor, and Manhasset Bay. Samples from the collection from Mt. Hope Bay, Rhode Island (the nearest sampling site to the north) were significantly different from those samples from the Connecticut River. According to Dr. Wirgin, "this suggests that reproductive isolation among estuaries in western Long Island Sound (west of the Connecticut) may be weak and that young life stages may mix or that homing fidelity in the area is not great." This information is preliminary and, according to Dr. Wirgin, more areas should be sampled and larger sample sizes should be taken before a definitive conclusion regarding the genetic distinctness of fish from western Long Island Sound can be proven. Also, in order to determine if most individual estuaries are genetically distinct or if fish in estuaries in different geographic regions are separate genetic units, it is necessary to sample more immediately contiguous estuaries (Wirgin 2003).

The petition asserts that the winter flounder populations in western Long Island Sound should be listed as either threatened or endangered. By specifying the populations in western Long Island Sound, the petitioner attempts to distinguish between fish from the western portion of the Sound and the remainder of Long Island Sound, which is all part of the southern New England/ Middle Atlantic stock. However, current scientific data do not suggest that fish from the western portion of the Sound are discrete from fish from the remainder of the Sound because, as discussed above, the samples taken near the Connecticut River were genetically similar to those from areas farther west in the Sound. Also, current information is insufficient to conclude whether fish from Long Island Sound as a whole represent a discrete population and, therefore, should be considered separate from fish from the remainder of the Southern New England/Middle Atlantic stock. As such, we will consider the Southern New England/Middle Atlantic stock to be a separate stock for the purposes of this petition. Information on the status of the Southern New England/ Middle Atlantic stock will be considered to determine whether it should be listed as threatened or endangered under the ESA. If the available information were to indicate that the status of this stock may be threatened or endangered, NOAA Fisheries would need to do a thorough analysis in the status review to show that this stock meets the criteria for a DPS because under the ESA, only species, subspecies, and DPSs of vertebrate species can be listed.

Southern New England/Middle Atlantic Population

To assess whether there is sufficient information to indicate that listing this stock may be warranted, NMFS will consider available information on threats and status of winter flounder from the New England/Middle Atlantic region.

The petitioner asserts that EPA's program to reduce nutrient loading to the Sound has resulted in significant reductions in primary production resulting in declines in abundance and size of once numerous sport fish, including winter flounder and cunner. Available information does not indicate that the New England/Middle Atlantic stock of cunner and winter flounder are limited by primary production. In fact the EPA's program has most likely benefited the species. According to the EPA, total nitrogen loads from point sources to the waters of the Sound have decreased significantly over the last ten years as sewage treatment plants (STPs) have implemented more stringent controls. In the summer, hypoxia has had a significant adverse impact on the aquatic habitat and residents of the Sound. Hypoxia is generally most severe in bottom waters. Winter flounder are demersal and as such, they may encounter areas with depleted oxygen concentrations. A reduction in hypoxia would result in an increase in the amount of habitat available for this and other demersal species.

EPA has indicated that although there has been a reduction in the areal extent and duration of hypoxic events since the late 1980s in Long Island Sound, summer hypoxia still represents a significant impairment to the water quality of the Sound and still continues to adversely affect the living marine resources present (EPA 2002). As such, the states of Connecticut and New York have completed and the EPA has approved a TMDL plan for nitrogen. It is assumed that this program will result in a reduction in anthropogenic inputs of nitrogen to the Sound (EPA 2002).

The Magnuson-Stevens Fishery Conservation and Management Act (MSFCMA), as amended by the Sustainable Fisheries Act in 1996, requires that the regional fishery management councils describe and identify essential fish habitat (EFH), identify actions to conserve and enhance that EFH, and minimize the adverse effects of fishing on EFH to the extent practicable. EFH has been defined by Congress as "those waters and substrate necessary to fish for spawning, breeding, feeding or growth to maturity." EFH has been identified for all life stages of winter flounder in Long Island Sound and many other bays and estuaries located in the Southern New England/Middle Atlantic region. As such, actions that affect the habitat in these areas are subject to EFH consultation. The available information suggests that the regulatory mechanisms to conserve existing habitat and restore areas within this region are sufficient to protect this species.

The petitioner asserts that predation has not had a significant role in the decline in winter flounder in western Long Island Sound. Available information and that contained in the petition is not sufficient to conclude that an increase in predation has resulted in the decline in winter flounder abundance.

According to the Connecticut Department of Environmental Protection (CT DEP), the new winter flounder index for the spring obtained from the 2003 Long Island Sound Trawl Survey is 21.12 fish/tow which is down from 25.5 fish/tow in 2002. However, the geometric mean increased from 6.31 kg/ tow in 2002 to 6.56 kg/tow in 2003 (Pers. Comm. Kurt Gottschall, CT DEP 2003). This indicates that the average size of winter flounder in Long Island may be increasing.

According to the information in the petition, winter flounder historically were the basis of a significant spring and fall recreational fishery. However, currently, there are no spring or fall winter flounder fishing tournaments due to the decline in abundance and size of fish caught. The 2002 stock assessment for winter flounder states that the Southern New England/Mid-Atlantic winter flounder stock complex is overfished and overfishing is occurring. According to the 2002 stock assessment for winter flounder, "spawning stock biomass declined substantially from 13,000–14,000 metric tons (mt) during the early 1980s to only 2,700 mt during 1994–1996, but has increased since the mid 1990s to about 7,600 mt in 2001 due to reduced fishing mortality rates since 1997. The arithmetic average recruitment from 1981 to 2001 is 23.9 million age–1 fish, with a median of 18.9 million fish. Recent recruitment to the stock has been below average since 1989. The 2001 year class, at only 5.6 million fish, is the smallest in the 22–year time series." Therefore, while recruitment may be decreasing, the spawning stock biomass of the New England/Middle Atlantic stock of winter flounder seems to be increasing.

Petition Finding

After reviewing the information contained in the petition, as well as information readily available to NMFS' scientists, NMFS has determined that the petition does not present substantial scientific or commercial information indicating that the petitioned action may be warranted. For cunner, sufficient scientific or commercial information to support conducting a status review of cunner in western Long Island Sound is not currently available. For winter flounder, recent studies on nuclear DNA are not sufficient to support the contention that winter flounder from western Long Island Sound are a DPS, or that winter flounder from Long Island Sound are a DPS. While the petition states that winter flounder catches have declined in western Long Island Sound to such an extent that the population will not recover, NMFS does not believe that the information presented is substantial enough to warrant a status review at this time. This finding is supported by information contained within the 2002 stock assessment for winter flounder, which has shown an increase in spawning stock biomass of the Southern New England/Mid-Atlantic stock as a result of reduced fishing mortality rates. If new information becomes available to suggest that cunner and winter flounder may in fact warrant listing under the ESA, NMFS will reconsider conducting species status reviews.

References

Atlantic States Marine Fisheries Commission. 2003. Public information document for Amendment I to the Interstate Fishery Management Plan for Inshore Stocks of Winter Flounder.

Prepared by Lydia Munger, Fishery Managment Plan Coordinator. 1444 Eye Street, NW, 6th Floor, Washington, DC 20005.

Collette, B. B. and G. Klein-MacPhee, editors. 2002. Bigelow and Schroeder's Fishes of the Gulf of Maine. Smithsonian Institution Press, Washington DC.

Connecticut Department of Environmental Protection. 2002. A study of marine recreational fisheries in Connecticut. Federal Aid in Sport Fish Restoration. F–54–R–21 Annual Performance Report. March 1, 2001–February 28, 2002.

Connecticut Department of Environmental Protection. 2003. Marine Finfish Survey. Draft report in prep.

Environmental Protection Agency. 2002. The 2001 CCMP Implementation Tracking Report for January - December 2001. The Comprehensive Conservation and Management Plan - Long Island Sound Study.

Gottschall, K. 2003. Personal Communication. Connecticut Department of Environmental Protection, Marine Fisheries Division. Old Lyme, CT 06371.

Meise, C., J.S. Collie, J. Widman, P. Howell. 1999. Growth and mortality of juvenile winter flounder in two New England estuaries. Estuaries 22(2A):297–303.

Northeast Fisheries Science Center. 2003. Report of the 36th Northeast Regional Stock Assessment Workshop (36th SAW): Stock Assessment Review Committee (SARC)

Consensus Summary of Assessments. National Marine Fisheries Serv., Woods Hole Lab., 166 Water St., Woods Hole, MA 02543. Pp. 139–163.

Pereira, J.J., R. Goldberg, J.J. Ziskowski, P.L. Berrien, W.W. Morse, and D.L. Johnson. Essential fish habitat source document: winter flounder, *Pseudopleuronectes americanus*, life history and habitat characteristics. NOAA Technical Memorandum NMFS-NE–138. September 1999.

Wirgin, I. 2003. Stock identification and mixed stock analyses of winter flounder (*Pleuronectes americanus*). NYSG Completion Report. Submitted March 17, 2003.

Authority: 16 U.S.C. 1531 *et seq.*.

Dated: January 22, 2004.

Rebecca Lent,

Deputy Assistant Administrator for Regulatory Programs, National Marine Fisheries Service.

[FR Doc. 04–1978 Filed 1–29–04; 8:45 am]

BILLING CODE 3510–22–S

COMMITTEE FOR THE IMPLEMENTATION OF TEXTILE AGREEMENTS

Request for Public Comments on Commercial Availability Request under the African Growth and Opportunity Act (AGOA) and the Andean Trade Promotion and Drug Eradication Act (ATPDEA)

January 28, 2004.

AGENCY: The Committee for the Implementation of Textile Agreements

ACTION: Request for public comments concerning a request for a determination that two patented fusible interlining fabrics, used in the construction of waistbands, cannot be supplied by the domestic industry in commercial quantities in a timely manner under the AGOA and the ATPDEA.

SUMMARY: On January 20, 2004, the Chairman of CITA received a petition from Levi Strauss and Co. alleging that a certain ultra-fine Lycra crochet material cannot be supplied by the domestic industry in commercial quantities in a timely manner. The petition requests that apparel containing waistbands of such fabrics be eligible for preferential treatment under the AGOA and the ATPDEA. CITA hereby solicits public comments on this request, in particular with regard to whether such fabrics can be supplied by the domestic industry in commercial quantities in a timely manner. Comments must be submitted by February 17, 2004, to the Chairman, Committee for the Implementation of Textile Agreements, Room 3001, United States Department of Commerce, 14th and Constitution Avenue, N.W. Washington, DC 20230.

FOR FURTHER INFORMATION CONTACT: Richard Stetson or Martin Walsh, International Trade Specialists, Office of Textiles and Apparel, U.S. Department of Commerce, (202) 482-3400.

SUPPLEMENTARY INFORMATION:

Authority: Section 112(b)(5)(B) of the AGOA; Section 1 of Executive Order No. 13191 of January 17, 2001; Presidential Proclamations 7350 of October 4, 2000; Section 204 (b)(3)(B)(ii) of the ATPDEA, Presidential Proclamation 7616 of October 31, 2002, Executive Order 13277 of November 19, 2002, and the United States Trade Representative's Notice of Further Assignment of Functions of November 25, 2002.

Background

The AGOA and the ATPDEA provide for quota- and duty-free treatment for qualifying textile and apparel products. Such treatment is generally limited to products manufactured from yarns and fabrics formed in the United States or a beneficiary country. The AGOA and the ATPDEA also provide for quota- and duty-free treatment for apparel articles that are both cut (or knit-to-shape) and sewn or otherwise assembled in one or more beneficiary countries from fabric or yarn that is not formed in the United States, if it has been determined that such fabric or yarn cannot be supplied by the domestic industry in commercial quantities in a timely manner. In Executive Order No. 13191 (66 FR 7271) and pursuant to Executive Order No. 13277 (67 FR 70305) and the United States Trade Representative's Notice of Redelegation of Authority and Further Assignment of Functions (67 FR 71606), CITA has been delegated the authority to determine whether yarns or fabrics cannot be supplied by the domestic industry in commercial quantities in a timely manner under the AGOA or the ATPDEA. On March 6, 2001, CITA published procedures that it will follow in considering requests (66 FR 13502).

On January 20, 2004, the Chairman of CITA received a petition from Levi Strauss and Co. alleging that certain ultra-fine Lycra crochet outer-fusible material with a fold line that is knitted into the fabric and a fine Lycra crochet inner-fusible material with an adhesive coating that is applied after going through a finishing process to remove all shrinkage from the product, classified under item 5903.90.2500 of the Harmonized Tariff Schedule of the United States (HTSUS), for use in apparel articles (waistbands), cannot be supplied by the domestic industry in commercial quantities in a timely manner and requesting quota- and duty-free treatment under the AGOA and the ATPDEA for apparel articles that are both cut and sewn in one or more AGOA or ATPDEA beneficiary countries utilizing such fabrics.

The two fabrics at issue are:

Fusible Interlining 1 -

An ultra-fine Lycra crochet outer-fusible material with a fold line that is knitted into the fabric. A patent is pending for this fold-line fabric.

The fabric is a 45mm wide base substrate, crochet knitted in narrow width, synthetic fiber based (49% polyester/43% elastane/8% nylon with a weight of 4.4 oz., a 110/110 stretch and a dull yarn), stretch elastomeric material with adhesive coating that has the following characteristics:

(a) The 45mm is divided as follows: 34mm solid followed by a 3mm seam allowing it to fold over followed by 8mm of solid.

(b) In the length it exhibits excellent stretch and recovery properties at low extension levels.

(c) It is delivered pre-shrunk with no potential for relaxation shrinkage during high temperature washing or fusing and deliveredlap laid, i.e., tension free adhesion level will be maintained or improved through garment processing temperatures of up to 350 degrees and dwell times of 20 minute durations.

(d) The duration and efficacy of the bond will be such that the adhesive will not become detached from the fabric or base substrate during industrial washing or in later garment wear or after-care of 50 home washes.

In summary, the desired fabric will be an interlining fabric with the above properties. The finished interlining fabric is a fabric that has been coated with an adhesive coating after going through a finishing process to remove all shrinkage from the product and impart a stretch to the fabric. This finishing process of imparting stretch to fabrics is patented, U.S. Patent 5,987,721.

Fusible Interlining 2 -

A fine Lycra crochet inner-fusible material with an adhesive coating that is applied after going through a finishing process to remove all shrinkage from the product. (Sample ι2) This finishing process of imparting stretch to fabrics is patented, U.S. Patent 5,987,721. Specifically, the fabric is a 40mm synthetic fiber based stretch elastomeric fusible (80% nylon type 6/20% spandex with a weight of 4.4 oz., a 110/110 stretch and a dull yarn), with the following characteristics:

(a) It is supplied pre-coated with an adhesive that will adhere to 100% cotton and other composition materials such as polyester/cotton blends during fusing at a temperature of 180 degrees.

(b) The adhesive is of a melt flow index which will not strike back through the interlining substrate or strike through the fabric to which it is fused and whose adhesion level will be maintained or improved through garment processing temperatures of up to 350 degrees and dwell times of 20 minute durations.

(c) The duration and efficacy of the bond will be such that the adhesive will not become detached from the fabric or base substrate during industrial washing or in later garment wear or after-care of 50 home washes.

(d) Delivered on rolls of more than 350 yards or lap laid in boxes.

Both interlining fabrics are classifiable under 5903.90.2500, HTSUS. The adhesive coating adds approximately 25% - 30% weight to the fusible interlining 1 and adds approximately 20% - 25% weight to the fusible interlining 2.

The fusible interlining fabrics are used in the construction of waistbands in pants, shorts, skirts, and other similar products that have waistbands.

Fusible interlining 1 reinforces the twill pant fabric and also exclusively contributes to the "stretch ability" of the twill pant fabric in the waistband area. Fusible interlining 2 is used on the underside of the waistband lining fabric. This interlining reinforces the waistband lining, which is made from pocketing-type fabric, and also exclusively contributes to that fabric's "stretch ability." It also serves to "firm up" the seam area of the waistband lining so that the fabric will not rip or otherwise be damaged during the assembly/sewing process.

CITA is soliciting public comments regarding this request, particularly with respect to whether these fabrics can be supplied by the domestic industry in commercial quantities in a timely manner. Also relevant is whether other fabrics that are supplied by the domestic industry in commercial quantities in a timely manner are substitutable for these fabrics for purposes of the intended use. Comments must be received no later than February 17, 2004. Interested persons are invited to submit six copies of such comments or information to the Chairman, Committee for the Implementation of Textile Agreements, room 3100, U.S. Department of Commerce, 14th and Constitution Avenue, N.W., Washington, DC 20230.

If a comment alleges that these fabrics can be supplied by the domestic industry in commercial quantities in a timely manner, CITA will closely review any supporting documentation, such as a signed statement by a manufacturer of the fabrics stating that it produces the fabrics that are the subject of the request, including the quantities that can be supplied and the time necessary to fill an order, as well as any relevant information regarding past production.

CITA will protect any business confidential information that is marked business confidential from disclosure to the full extent permitted by law. CITA will make available to the public non-confidential versions of the request and non-confidential versions of any public comments received with respect to a request in room 3100 in the Herbert Hoover Building, 14th and Constitution Avenue, N.W., Washington, DC 20230. Persons submitting comments on a request are encouraged to include a non-confidential version and a non-confidential summary.

James C. Leonard III,

Chairman, Committee for the Implementation of Textile Agreements.

[FR Doc. 04–2068 Filed 1–28–04; 3:11 pm]

BILLING CODE 3510–DR–S

COMMITTEE FOR THE IMPLEMENTATION OF TEXTILE AGREEMENTS

Request for Public Comments on Commercial Availability Request under the African Growth and Opportunity Act (AGOA), the United States-Caribbean Basin Trade Partnership Act (CBTPA), and the Andean Trade Promotion and Drug Eradication Act (ATPDEA)

January 28, 2004.

AGENCY: The Committee for the Implementation of Textile Agreements

ACTION: Request for public comments concerning a request for a determination that three patented fusible interlining fabrics, used in the construction of waistbands, cannot be supplied by the domestic industry in commercial quantities in a timely manner under the AGOA, the CBTPA, and the ATPDEA.

SUMMARY: On January 20, 2004, the Chairman of CITA received a petition from Levi Strauss and Co. alleging that a certain fusible composition material, of the specifications detailed below, classified in subheading 5903.90.2500 of the Harmonized Tariff Schedule of the United States (HTSUS) cannot be supplied by the domestic industry in commercial quantities in a timely manner. The petition requests that apparel containing waistbands of such fabrics be eligible for preferential treatment under the AGOA, the CBTPA, and the ATPDEA. CITA hereby solicits public comments on this request, in particular with regard to whether such fabrics can be supplied by the domestic industry in commercial quantities in a timely manner. Comments must be submitted by February 17, 2004, to the Chairman, Committee for the Implementation of Textile Agreements, Room 3001, United States Department of Commerce, 14th and Constitution Avenue, NW. Washington, DC 20230.

FOR FURTHER INFORMATION CONTACT: Richard Stetson or Martin Walsh, International Trade Specialists, Office of Textiles and Apparel, U.S. Department of Commerce, (202) 482-3400.

SUPPLEMENTARY INFORMATION:

Authority: Section 112(b)(5)(B) of the AGOA; Section 213(b)(2)(A)(v)(II) of the Caribbean Basin Economic Recovery Act, as added by Section 211(a) of the CBTPA; Sections 1 and 6 of Executive Order No. 13191 of January 17, 2001; Presidential Proclamations 7350 and 7351 of October 4, 2000; Section 204 (b)(3)(B)(ii) of the ATPDEA, Presidential Proclamation 7616 of October 31, 2002, Executive Order 13277 of November 19, 2002, and the United States Trade Representative's Notice of Further Assignment of Functions of November 25, 2002.

Background

The AGOA, the CBTPA, and the ATPDEA provide for quota- and duty-free treatment for qualifying textile and apparel products. Such treatment is generally limited to products manufactured from yarns and fabrics formed in the United States or a beneficiary country. The AGOA, the CBTPA, and the ATPDEA also provide for quota- and duty-free treatment for apparel articles that are both cut (or knit-to-shape) and sewn or otherwise assembled in one or more beneficiary countries from fabric or yarn that is not formed in the United States, if it has been determined that such fabric or yarn cannot be supplied by the domestic industry in commercial quantities in a timely manner. In Executive Order No. 13191 (66 FR 7271) and pursuant to Executive Order No. 13277 (67 FR 70305) and the United States Trade Representative's Notice of Redelegation of Authority and Further Assignment of Functions (67 FR 71606), CITA has been delegated the authority to determine whether yarns or fabrics cannot be supplied by the domestic industry in commercial quantities in a timely manner under the AGOA, the CBTPA, or the ATPDEA. On March 6, 2001, CITA published procedures that it will follow in considering requests (66 FR 13502).

On January 20, 2004, the Chairman of CITA received a petition from Levi Strauss and Co. alleging that certain fusible composition material, of the specifications detailed below, classified in HTSUS subheading 5903.90.2500, for use in waistbands of apparel articles, cannot be supplied by the domestic industry in commercial quantities in a timely manner and requesting quota- and duty-free treatment under the AGOA, the CBTPA, and the ATPDEA for apparel articles that are both cut and sewn in one or more beneficiary countries utilizing such fabrics.

The three fabrics at issue are:

Fusible A - Composition

A knitted outer-fusible material. The fusible width variance is not less the 3/4 inches wide (18 to 20 mm) or more the 6 inches (153 to 155 mm) wide. The fabric substrate is, synthetic fiber based (made of 49 percent polyester / 43 percent elastomeric filament / 8 percent nylon with an average weight of 4.4 ounces, not greater than 5 ounces, a 110/110 stretch, and a dull yarn), stretch elastomeric material with an adhesive (thermoplastic resin) coating. This fusible may have a fiber variance of up to 3 percent for each fiber.

Fusible B - Composition

A knitted inner and outer fusible material with an adhesive (thermoplastic resin) coating that is applied after going through a finishing process to remove all shrinkage from the product. The fabric is a synthetic fiber based stretch elastomeric fusible consisting of 80 percent nylon type 6 / 20 percent elastomeric filament with a weight of 4.4 ounces, not greater than 5 ounces, a 110/110 stretch, and a dull yarn. The fusible width variance is not less the 3/4 inches wide (18 to 20 mm) or more than 6 inches (153 to 155 mm) wide. This fusible may have a fiber variance of up to 3 percent for each fiber.

Fusible C - Composition

A knitted fusible material used to shape countour waistbands and is applied on top of the main fusible only as a reinforcement. The fusible width variance is not less than 1/4 inches wide (5 to 6 mm) or more than 1 inch (25 to 27 mm) wide. The fabric is 11.2 percent nylon / 34.4 percent polyester / 54.4 percent elastomeric at a weight of 300 grams to not greater than 400 grams per square meter. This fusible may have a fiber variance of up to 3 percent for each fiber.

With each of these, the following applies:

(a) In the length it exhibits excellent stretch and recovery properties at low extension levels.

9b) It is delivered pre-shrunk with no potential for relaxation shrinkage during high temperature washing or fusing and delivered lap laid, i.e., tension free.

(c) It is supplied pre-coated with an adhesive that will adhere to 100 percent cotton and other composition materials such polyester/cotton blend during fusing at a temperature of 180 degrees Celsius.

(d) The adhesive is of a melt flow index which will not strike back through the interlining substrate or strike through the fabric to which it is fused and whose adhesion level will be maintained or improved through garment processing temperatures of up to 350 degrees Fahrenheit and dwell times of 20 minute durations.

(e) The duration and efficacy of the bond will be such that the adhesive will not, during industrial washing, later garment wear or after-care of 30 home washes, become detached from the fabric or base substrate.

The finished interlining fabric is a fabric that has been coated with an adhesive coating after going through a finishing process to remove all shrinkage from the product and impart a stretch to the fabric. This finishing process of imparting stretch to fabric is patented, U.S. Patent 5,987,721.

CITA is soliciting public comments regarding this request, particularly with respect to whether these fabrics can be supplied by the domestic industry in commercial quantities in a timely manner. Also relevant is whether other fabrics that are supplied by the domestic industry in commercial quantities in a timely manner are substitutable for these fabrics for purposes of the intended use. Comments must be received no later than February 17, 2004. Interested persons are invited to submit six copies of such comments or information to the Chairman, Committee for the Implementation of Textile Agreements, room 3100, U.S. Department of Commerce, 14th and Constitution Avenue, NW., Washington, DC 20230.

If a comment alleges that these fabrics can be supplied by the domestic industry in commercial quantities in a timely manner, CITA will closely review any supporting documentation, such as a signed statement by a manufacturer of the fabrics stating that it produces the fabrics that are the subject of the request, including the quantities that can be supplied and the time necessary to fill an order, as well as any relevant information regarding past production.

CITA will protect any business confidential information that is marked business confidential from disclosure to the full extent permitted by law. CITA will make available to the public non-confidential versions of the request and non-confidential versions of any public comments received with respect to a request in room 3100 in the Herbert Hoover Building, 14th and Constitution Avenue, N.W., Washington, DC 20230. Persons submitting comments on a request are encouraged to include a non-confidential version and a non-confidential summary.

James C. Leonard III,

Chairman, Committee for the Implementation of Textile Agreements.

[FR Doc. 04–2069 Filed 1–28–04; 3:11 pm]

BILLING CODE 3510–DR–S

COMMODITY FUTURES TRADING COMMISSION

Sunshine Act Meetings

TIME AND DATE: 10 a.m., Wednesday, February 4, 2004.

PLACE: 1155 21st Street, NW., Washington, DC, Room 1012 Room.

STATUS: Open.

MATTERS TO BE CONSIDERED: The Commission will hold a public meeting to consider the application of the U.S. Futures Exchange, LLC, for contact market designation.

FOR FURTHER INFORMATION CONTACT: Jean A. Webb, 202–418–5100 or *http://www.cftc.gov.*

Catherine D. Dixon,

Assistant Secretary of the Commission.

[FR Doc. 04–2012 Filed 1–28–04; 8:58 am]

BILLING CODE 6351–01–M

DEPARTMENT OF DEFENSE

Department of the Air Force

Proposed Collection; Comment Request

AGENCY: Office of Admissions, Headquarters United States Air Force Academy Department of the Air Force, Department of Defense.

ACTION: Notice.

In compliance with Section 3506(c)(2)(A) the Paperwork Reduction Act of 1995, the Office of the Secretary of Defense announces the proposed reinstatement of a public 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 unity; (b) the accuracy of the agency's estimate of the burden 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 by March 30, 2004.

ADDRESSES: Written comments and recommendations on the proposed information collection should be sent to Office of Admissions, 2304 Cadet Drive, Suite 236, USAF Academy, CO 80840. Point of Contact is Ms. Shawn Hordemann, telephone 719–333–7291.

FOR FURTHER INFORMATION CONTACT: To request more information on this proposed information collection or to obtain a copy of the proposed and associated collection instruments, please write to the above address.

Title, Associated Form, and OMB Number: United States Air Force Academy School Officials's Evaluation of Candidate, United States Air Force Academy Form 145 (Proposed), OMB Number (New, OMB number needs to be assigned).

Needs and Uses: The information collection requirement is necessary to obtain data on candidate's background and aptitude in determining eligibility and selection to the Air Force Academy.

Affected Public: Individuals or Households.

Annual Burden Hours: 4100.

Number of Respondents: 4100.

Responses Per Respondent: 1.

Average Burden For Respondent: 60 Minutes.

Frequency: On occasion.

SUPPLEMENTARY INFORMATION:

Summary of Information Collection

The information collected on this form is required by 10 U.S.C. 9346. The respondents are students who are applying for admission to the United States Air Force Academy. Each student's background and aptitude is reviewed to determine eligibility. If the information on this form is not collected, the individual cannot be considered for admittance to the Air Force Academy.

Pamela Fitzgerald,

Air Force Federal Register Liaison Officer.

[FR Doc. 04–1982 Filed 1–29–04; 8:45 am]

BILLING CODE 5001–05–P

DEPARTMENT OF DEFENSE

Department of the Air Force

Air Force Academy Board of Visitors Meeting

Pursuant to Section 9355, Title 10, United States Code, the Air Force Academy Board of Visitors will meet at the Rayburn House Office Building, Washington, DC, 3 February 2004. The purpose of the meeting is to consider morale and discipline, the curriculum, instruction, physical equipment, fiscal affairs, academic methods, and other matters relating to the Academy.

A portion of the meeting will be open to the public while other portions will be closed to the public to discuss matters listed in Paragraphs (2), (6), and Subparagraph (9)(B) of Subsection (c) of Section 552b, Title 5, United States Code. The determination to close certain sessions is based on the consideration that portions of the briefings and discussion will relate solely to the internal personnel rules and practices of the Board of Visitors or the Academy; involve information of a personal nature, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy; or involve discussions of information the premature disclosure of which would be likely to frustrate implementation of future agency action. Meeting sessions will be held in Room 2212 of the Rayburn Building.

For further information, contact Lieutenant Colonel Tom Joyce, Military Assistant, Office of the Deputy Assistant Secretary of the Air Force (Force Management and Personnel), SAF/MRM, 1660 Air Force Pentagon, Washington, DC, 20330–1660, (703) 693–9765.

Pamela D. Fitzgerald,

Air Force Federal Register Liaison Officer.

[FR Doc. 04–1986 Filed 1–29–04; 8:45 am]

BILLING CODE 5001–05–P

DEPARTMENT OF DEFENSE

Department of the Navy

Public Hearings for the Draft Environmental Impact Statement for Purchase of Land for a Naval Special Operations Forces Training Range, Hancock County, MS

AGENCY: Department of the Navy, DOD.

ACTION: Notice.

SUMMARY: Pursuant to Section (102)(2) of the National Environmental Policy Act of 1969, and the regulations implemented by the Council on Environmental Quality (40 CFR Parts 1500–1508), the Department of the Navy (Navy) has prepared and filed with the U.S. Environmental Protection Agency (EPA) a Draft Environmental Impact Statement (DEIS) on January 30, 2004, to evaluate the potential environmental consequences of purchasing 5,200 acres inside the northwestern acoustic buffer zone at the National Aeronautical and Space Administration's John C. Stennis Space Center (Stennis Space Center) in

Hancock County, MS. The acquired acreage would be used as a Naval Special Operations Forces Training Range where exercises using Short Range Training Ammunition (SRTA) could be conducted. The Navy will conduct two public hearings to receive oral and written comments on the DEIS. Federal, state, and local agencies and interested individuals are invited to be present or represented at the public hearings. Navy representatives will be available to clarify information related to the DEIS. This notice announces the dates and locations of the public hearings for this DEIS.

DATES AND ADDRESSES: Two public hearings will be held. The first public hearing will be on Tuesday, February 17, 2004, from 7 p.m. to 9 p.m. at Hancock County Court House, 150 Main St, Bay St. Louis, MS. The second hearing will be on Wednesday, February 18, 2004, from 7 p.m. to 9 p.m. at Slidell City Auditorium, 2055 2ND St, Slidell, LA.

FOR FURTHER INFORMATION CONTACT: Mr. Richard Davis, Southern Div., Naval Facilities Engineering Command, P.O. Box 190010, North Charleston, SC 29419–9010. Telephone (843) 820–5589, facsimile (843) 820–7472, or E-mail: *richard.a.davis1@navy.mil.*

SUPPLEMENTARY INFORMATION: A Notice of Intent to prepare this DEIS was published in the **Federal Register**, 68 FR 9998, March 3, 2003. Public scoping meetings were held on March 18, 2003, at the Hancock High School, Kiln, MS and on March 20, 2003, at the Slidell City Auditorium, Slidell, LA.

The proposed action is to purchase 5,200 acres of real estate to establish a riverine and jungle training range for Naval Special Operations Forces where short range training ammunition (SRTA) up to .50 caliber can be conducted. SRTA is a plastic, non-lead, non-explosive projectile with a limited flight profile.

Naval Special Operations Forces would conduct water-to-land SRTA fire training from the East Pearl River into the range and land-to-land SRTA fire would be conducted wholly inside the range perimeter. The following training activities would also occur within the range perimeter: land patrolling and reconnaissance by foot and passenger vehicles; equipment testing and evaluation; immediate action drills; communications drills; use of maritime unmanned aerial vehicles, unmanned riverine observation craft, and High Mobility Multi-purpose Wheeled Vehicles; and insertions and extractions via helicopter. The establishment of an interior range perimeter safety buffer and "no-fire" sectors along the East Pearl and Mikes Rivers would preclude impacts on adjacent land and water areas outside the range.

Alternatives considered in the DEIS include various sites in the vicinity of the Stennis Space Center. The preferred locational alternative is Alternative Range Location 3—Establishment of training areas along reaches of the East Pearl River and Mikes River. In addition, the DEIS evaluates three training alternatives that address the type and tempo of activities to be conducted on the range. Implementation of the proposed action is not expected to result in any significant short or long term impacts on physical, biological, or socioeconomic resources.

The DEIS has been distributed to various Federal, state, and local agencies, elected officials, and interested parties, and is available for public review at the following libraries: Hancock Public Library, Bay St. Louis Branch, 312 Hwy 90, Bay St. Louis, MS; and St. Tammany Parish Library, Slidell Branch, 555 Robert Blvd, Slidell, LA.

Oral statements presented at the public hearing will be heard and transcribed by a stenographer; however, to ensure the accuracy of the record, all statements should be submitted in writing. All statements, both oral and written, will become part of the public record on the DEIS and will be responded to in the Final Environmental Impact Statement (FEIS). Equal weight will be given to both oral and written statements.

In the interest of available time and to ensure that all who wish to give an oral statement have the opportunity to do so, each speaker's comments will be limited to three (3) minutes. If a longer statement is to be presented, it should be summarized at the public hearing and the full text submitted in writing either at the hearing or faxed or mailed to: SBT–22 Range EIS, c/o Commanding Officer, Southern Division, Naval Facilities Engineering Command, P.O. Box 190010, North Charleston, SC 29419–9010, Attn: Code ES12/RD (Richard A. Davis), telephone (843) 820–5589 or facsimile (843) 820–7472. All written comments postmarked by March 15, 2004, will become part of the official public record and will be responded to in the FEIS.

Dated: January 27, 2004.

J. T. Baltimore,

Lieutenant Commander, Judge Advocate General's Corps, U.S. Navy, Alternate Federal Register Liaison Officer.

[FR Doc. 04–1951 Filed 1–29–04; 8:45 am]

BILLING CODE 3810–FF–P

DEPARTMENT OF DEFENSE

Department of the Navy

Meeting of the Chief of Naval Operations (CNO) Executive Panel

AGENCY: Department of the Navy, DOD.

ACTION: Notice of closed meeting.

SUMMARY: The CNO Executive Panel is to report the recommendations of the Naval Special Warfare Study Group to the Chief of Naval Operations. This meeting will consist of discussions relating to Naval Special Warfare and its integration with conventional forces.

DATES: The meeting will be held on Monday, February 9, 2004, from 1 p.m. to 1:30 p.m.

ADDRESSES: The meeting will be held at the CNO's office, Room 4E540, 2000 Navy Pentagon, Washington, DC 20350–2000.

FOR FURTHER INFORMATION CONTACT: Lieutenant Commander Christopher Corgnati, CNO Executive Panel, 4825 Mark Center Drive, Alexandria, VA 22311, (703) 681–4909.

SUPPLEMENTARY INFORMATION: Pursuant to the provisions of the Federal Advisory Committee Act (5 U.S.C. App. 2), these matters constitute classified information that is specifically authorized by Executive Order to be kept secret in the interest of national defense and are, in fact, properly classified pursuant to such Executive Order. Accordingly, the Secretary of the Navy has determined in writing that the public interest requires that all sessions of the meeting be closed to the public because they will be concerned with matters listed in section 552b(c)(1) of title 5, United States Code.

Dated: January 27, 2004.

J.T. Baltimore,

Lieutenant Commander, Judge Advocate General's Corps, U.S. Navy, Alternate Federal Register Liaison Officer.

[FR Doc. 04–2048 Filed 1–29–04; 8:45 am]

BILLING CODE 3810–FF–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. IC04–580–000, FERC Form 580]

Commission Information Collection Activities, Proposed Collection; Comment Request Extension

January 22, 2004.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice.

SUMMARY: In compliance with the requirements of section 3506(c)(2)(a) of the Paperwork Reduction Act of 1995, 44 U.S.C. 3506(c)(2)(A), the Federal Energy Regulatory Commission (Commission) is soliciting public comment on the specifics of the information collection described below.

DATES: Comments on the collection of information are due by March 26, 2004.

ADDRESSES: Copies of the proposed collection of information can be obtained from Michael Miller, Office of the Executive Director, ED–30, 888 First Street, NE., Washington, DC 20426. Comments may be filed either in paper format or electronically. Those parties filing electronically do not need to make a paper filing. For paper filings, the original and 14 copies of such comments should be submitted to the Office of the Secretary, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426 and refer to Docket IC04–580–000.

Documents filed electronically via the Internet must be prepared in WordPerfect, MS Word, Portable Document Format, or ASCII format. To file the document, access the Commission's Web site at *http://www.ferc.gov* and click on "Make an E-filing," and then follow the instructions for each screen. First time users will have to establish a user name and password. The Commission will send an automatic acknowledgement to the sender's e-mail address upon receipt of comments.

All comments may be viewed, printed or downloaded remotely via the Internet through FERC's home page using the eLibrary link. For user assistance, contact *FERCOnlineSupport@ferc.gov* or toll-free at (866) 208–3676 or for TTY, contact (202) 502–8659.

FOR FURTHER INFORMATION CONTACT: Michael Miller may be reached by telephone at (202) 502–8415, by fax at (202) 273–0873, and by e-mail at *michael.miller@ferc.gov.*

SUPPLEMENTARY INFORMATION:

Description

The information collected under FERC Form No. 580, "Interrogatory on Fuel and Energy Purchase Practices, Docket No. IN79–6" (OMB Control No. 1902–0137) is used by the Commission to carry out its responsibilities in implementing the statutory provisions of the Federal Power Act (FPA). The FPA was amended by the Public Utility Regulatory Policies Act (49 Stat. 851; 16 U.S.C. 824d) to require the Commission to review "not less frequently than every two (2) years * * * of practices * * * to ensure efficient use of resources (including economical purchase and use of fuel and electric energy) * * *." The information is used to: (1) Review as mandated by statute, fuel purchase and cost recovery practices to insure efficient use of resources, including economical purchase and use of fuel and electric energy, under fuel adjustment clauses on file with the Commission; (2) evaluate fuel costs in individual rate filings; (3) to supplement periodic utility audits; and (4) to monitor changes and trends in the electric wholesale market. The information has also been used by the Energy Information Administration under a Congressional mandate to study various aspects of coal, oil, and gas transportation rates. Electric market participants and the public are using the information to assess the marketplace during its transition to a fully competitive regime.

Action: The Commission is requesting a three-year extension of the current expiration date, with no changes to the existing collection of data.

Burden Statement: Public reporting burden for this collection is estimated as:

Number of respondents annually (1)	Number of responses per respondent (2)	Average burden hours per response (3)	Total annual burden hours (1)×(2)×(3)
114	*59.5	64	3,648

(114 responses every two years)
Estimated cost burden to Respondents: 3,648 hours ÷ 2,080 hours per year × $107,185 = $196,231.

The reporting burden includes the total time, effort, or financial resources expended to generate, maintain, retain, disclose, or provide the information including: (1) Reviewing instructions; (2) developing, acquiring, installing, and utilizing technology and systems for the purposes of collecting, validating, verifying, processing, maintaining, disclosing and providing information; (3) adjusting the existing ways to comply with any previously applicable instructions and requirements; (4) training personnel to respond to a collection of information; (5) searching data sources; (6) completing and reviewing the collection of information; and (7) transmitting, or otherwise disclosing the information.

The estimate of cost for respondents is based upon salaries for professional clerical support, as well as direct and indirect overhead costs. Direct costs include all costs directly attributable to providing this information, such as administrative costs and the cost of information technology. Indirect or overhead costs are costs incurred by an organization in support of its mission. These costs apply to the activities which benefit the whole organization rather than any one particular function or activity.

Comments are invited on: (1) Whether the proposed collection of information is necessary for the proper performance of the functions of the Commission, including whether the information will have practical utility; (2) the accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used; (3) ways to enhance the quality, utility and clarity of the information to be collected; and (4) ways to minimize the burden of the collection of information on those who are to respond, including the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, *e.g.*, permitting electronic submission of responses.

Pubic Utility Regulatory Policies Act.

Magalie R. Salas,

Secretary.

[FR Doc. E4–147 Filed 1–29–04; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. RP04–142–000]

ANR Pipeline Company; Notice of Service Agreement Filing

January 22, 2004.

Take notice that on January 16, 2004, ANR Pipeline Company (ANR), tendered for filing and approval, one service agreement (Agreement) between ANR and Kaztex Energy Management Inc. pursuant to ANR's Rate Schedule FTS–1. ANR also tendered for filing as part of its FERC Gas Tariff, Second Revised Volume No. 1, Second Revised Sheet No. 190A, with an effective date of February 16, 2004.

ANR requests the Commission find that the Agreement contains acceptable material deviations from ANR's Form of Service Agreement and accept the attached tariff sheet which references the Agreement as non-conforming.

Any person desiring to be heard or to protest said filing should file a motion to intervene or a protest with the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, in accordance with Sections 385.214 or 385.211 of the Commission's Rules and Regulations. All such motions or protests must be filed in accordance with Section 154.210 of the Commission's Regulations. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceedings. Any person wishing to become a party must file a motion to intervene. This filing is available for review at the Commission in the Public Reference Room or may be viewed on the Commission's Web site at *http://www.ferc.gov* using the eLibrary. Enter the docket number excluding the last three digits in the docket number field to access the document. For assistance, please contact FERC Online Support at *FERCOnlineSupport@ferc.gov* or toll-free at (866) 208–3676, or TTY, contact (202) 502–8659. The Commission strongly encourages electronic filings. *See*, 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site under the e-Filing link.

Magalie R. Salas,

Secretary.

[FR Doc. E4–154 Filed 1–29–04; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. CP02–233–002]

Equitrans, L.P.; Notice of Compliance Filing

January 22, 2004.

Take notice that on January 15, 2004, Equitrans, L.P. (Equitrans) tendered for filing as part of its FERC Gas Tariff, Original Volume No. 1, the following tariff sheets to become effective on January 1, 2004:

Third Revised Revised Sheet No. 1
Substitute Eighth Revised Sheet No. 5
Substitute Eleventh Revised Sheet No. 6
Substitute Fourth Revised Sheet No. 11
Substitute First Revised Sheet No. 202
Substitute Second Revised Sheet No. 203
Substitute First Revised Sheet No. 204
Substitute First Revised Sheet No. 205

Equitrans states that the foregoing tariff sheets are being filed to comply with the Commission's Order, issued herein on December 31, 2003.

Equitrans further states that its filing is being served on all parties to this proceeding, on all of Equitrans' existing customers, and upon the Pennsylvania Office of Consumer Advocate, Pennsylvania Public Utility Commission and the West Virginia Public Service Commission.

Any person desiring to protest said filing should file a protest with the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, in accordance with section 385.211 of the Commission's rules and regulations. All such protests must be filed in accordance with section 154.210 of the Commission's regulations. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceedings. This filing is available for review at the Commission in the Public Reference Room or may be viewed on the Commission's Web site at *http://www.ferc.gov* using the eLibrary link. Enter the docket number excluding the last three digits in the docket number field to access the document. For assistance, please contact FERC Online Support at *FERCOnlineSupport@ferc.gov* or toll-free at (866) 208–3676, or TTY, contact (202) 502–8659. The Commission strongly encourages electronic filings. *See*, 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site under the e-Filing link.

Magalie R. Salas,

Secretary.

[FR Doc. E4–145 Filed 01–29–04; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. CP02–233–001]

Equitrans, L.P.; Notice of Compliance Filing

January 22, 2004.

Take notice that on January 15, 2004, Equitrans, L.P. (Equitrans) tendered for filing as part of its FERC Gas Tariff, Original Volume No. 1, First Revised Sheet No. 0, to become effective on January 1, 2004.

Equitrans states that the foregoing tariff sheet is being filed to comply with the Commission's Order, issued herein on December 31, 2003.

Equitrans further states that its filing is being served on all parties to this proceeding, on all of Equitrans' existing customers, and upon the Pennsylvania Office of Consumer Advocate, Pennsylvania Public Utility Commission and the West Virginia Public Service Commission.

Any person desiring to protest said filing should file a protest with the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, in accordance with section 385.211 of the Commission's rules and regulations. All such protests must be filed in accordance with section 154.210 of the Commission's regulations. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceedings. This filing is available for review at the Commission in the Public Reference Room or may be viewed on the Commission's Web site at *http://www.ferc.gov* using the eLibrary link. Enter the docket number excluding the last three digits in the docket number field to access the document. For assistance, please contact FERC Online Support at *FERCOnlineSupport@ferc.gov* or toll-free at (866) 208–3676, or TTY, contact (202) 502–8659. The Commission strongly encourages electronic filings. *See*, 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site under the e-Filing link.

Magalie R. Salas,
Secretary.
[FR Doc. E4–155 Filed 1–29–04; 8:45 am]
BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. RP03–628–001]

Iroquois Gas Transmission System, L.P.; Notice of Proposed Changes in FERC Gas Tariff

January 22, 2004.

Take notice that on January 15, 2004, Iroquois Gas Transmission System, L.P. (Iroquois) tendered for filing as part of its FERC Gas Tariff, First Revised Volume No. 1 Sub. Twelfth Revised Sheet No. 4A. The proposed effective date of this revised tariff sheet is November 1, 2003.

Iroquois states that due to an inadvertent omission the credit for the Zone 2 (MFV) rate under the TCRA section entitled "ER/ED Commodity" is now being reinstated on Sub. Twelfth Revised Sheet No. 4A. Such credit will continue to be consistent with the other credits associated with the ER/ED service under the TCRA section.

Iroquois states that copies of its filing were served on all jurisdictional customers and interested State commissions.

Any person desiring to protest said filing should file a protest with the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, in accordance with section 385.211 of the Commission's rules and regulations. All such protests must be filed in accordance with section 154.210 of the Commission's regulations. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceedings. This filing is available for review at the Commission in the Public Reference Room or may be viewed on the Commission's Web site at *http://www.ferc.gov* using the eLibrary link. Enter the docket number excluding the last three digits in the docket number field to access the document. For assistance, please contact FERC Online Support at *FERCOnlineSupport@ferc.gov* or toll-free at (866) 208–3676, or TTY, contact (202) 502–8659. The Commission strongly encourages electronic filings. *See* 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site under the e-Filing link.

Magalie R. Salas,
Secretary.
[FR Doc. E4–153 Filed 1–29–04; 8:45 am]
BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. ER03–1345–000]

Midwest Independent Transmission System Operator, Inc.; Notice of Technical Conference

January 22, 2004.

Take notice that a technical conference will be held on Thursday, February 5, 2004, at 9 a.m. in room 3M–1, at the offices of the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426.

The technical conference will address the Midwest Independent Transmission System Operator, Inc.'s proposed revision to Attachment C of its Open Access Transmission Tariff, FERC Electric Tariff, Second Revised Volume 1 relating to the calculation of Available Flowgate Capacity, as proposed in its filing in the above docket.

Further details of the conference, including the agenda, will be specified in a subsequent notice. All interested persons and Staff are permitted to attend the conference, and registration is not required.

There will be no transcript of the conference and there will be no telephone link communications. For more information about the conference, please contact Nat Davis at (202) 502–6171 or *nathaniel.davis@ferc.gov.*

Magalie R. Salas,
Secretary.
[FR Doc. E4–146 Filed 01–29–04; 8:45 am]
BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. RP04–51–000]

Paiute Pipeline Company; Notice of Technical Conference

January 22, 2004.

In its Order issued December 4, 2003,[1] the Commission directed that a technical conference be held to better understand several aspects of Paiute Pipeline Company's November 7, 2003 tariff filing pertaining to segmentation and backhaul transportation.

[1] Paiute Pipeline Company, 105 FERC ¶ 61,271 (2003).

A technical conference will be held on Wednesday, February 18, 2004 at 10 a.m., in a room to be designated at the offices of the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426.

The conference will focus on the issues raised by the protesters in the proceeding. These issues include: (1) Whether Paiute's proposed tariff provisions would contradict the mandates of Order No. 637, which require pipelines to permit segmentation to the extent operationally feasible; (2) whether the proposal regarding backhaul transactions contains either unjustified or unclear restrictions on service; (3) an explanation as to why the proposal does not include any proposed rates for backhaul service; (4) whether backhaul nominations are available to shippers with interruptible contracts, or whether they are limited to shippers with firm transportation contracts; (5) whether there is an estimated date for when backhaul and segmentation transactions could be offered; and (6) the proposed gas scheduling computer system related to these issues.

All interested persons and staff are permitted to attend. Parties that wish to participate by phone should contact Sharon Dameron at (202) 502–8410 or at *sharon.dameron@ferc.gov* no later than Wednesday, February 11, 2004.

Magalie R. Salas,
Secretary.
[FR Doc. E4–144 Filed 01–29–04; 8:45 am]
BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. RP03–489–002]

Vector Pipeline L.P.; Notice of Request to Place Substitute Tariff Sheets Into Effect

January 22, 2004.

Take notice that on January 16, 2004, Vector Pipeline L.P. (Vector) filed pursuant to part 154 of the Commission(s regulations a request to substitute six revised tariff sheets for tariff sheets that were accepted by Commission Order issued January 14, 2004.

Vector states that the revised tariff sheets correct textual errors in the accepted tariff sheets. The proposed revised tariff sheets are:

2nd Sub Seventh Revised Sheet No. 118
2nd Sub Second Revised Sheet No. 132
2nd Sub Third Revised Sheet No. 153
2nd Sub Third Revised Sheet No. 154
2nd Sub Second Revised Sheet No. 204
2nd Substitute Original Sheet No. 274

The tariff sheets are proposed to be effective December 1, 2003.

Vector states that copies of this filing are being served on all jurisdictional customers, applicable state commissions, and participants in Docket No. RP03–489–000.

Any person desiring to protest said filing should file a protest with the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, in accordance with section 385.211 of the Commission's rules and regulations. All such protests must be filed in accordance with section 154.210 of the Commission's regulations. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceedings. This filing is available for review at the Commission in the Public Reference Room or may be viewed on the Commission's Web site at *http://www.ferc.gov* using the eLibrary link. Enter the docket number excluding the last three digits in the docket number field to access the document. For assistance, please contact FERC Online Support at *FERCOnlineSupport@ferc.gov* or toll-free at (866) 208–3676, or TTY, contact (202) 502–8659. The Commission strongly encourages electronic filings. *See* 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site under the e-Filing link.

Magalie R. Salas,
Secretary.
[FR Doc. E4–152 Filed 1–29–04; 8:45 am]
BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. RP03–323–001]

Williston Basin Interstate Pipeline Company; Notice of Negotiated Rates

January 22, 2004.

Take notice that on January 16, 2004, Williston Basin Interstate Pipeline Company (Williston Basin) tendered for filing with the Commission a negotiated Rate Schedule FT–1 service agreement associated with its Grasslands Pipeline Project in Docket Nos. CP02–37–000, *et al.*

Any person desiring to be heard or to protest said filing should file a motion to intervene or a protest with the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, in accordance with sections 385.214 or 385.211 of the Commission's rules and regulations. All such motions or protests must be filed in accordance with section 154.210 of the Commission's regulations. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceedings. Any person wishing to become a party must file a motion to intervene. This filing is available for review at the Commission in the Public Reference Room or may be viewed on the Commission's Web site at *http://www.ferc.gov* using the eLibrary. Enter the docket number excluding the last three digits in the docket number field to access the document. For assistance, please contact FERC Online Support at *FERCOnlineSupport@ferc.gov* or toll-free at (866) 208–3676, or TTY, contact (202) 502–8659. The Commission strongly encourages electronic filings. *See* 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site under the e-Filing link.

Magalie R. Salas,
Secretary.
[FR Doc. E4–151 Filed 1–29–04; 8:45 am]
BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. EC04–56–000, et al.]

Hardee Power Partners Limited, et al.; Electric Rate and Corporate Filings

January 23, 2004.

The following filings have been made with the Commission. The filings are listed in ascending order within each docket classification.

1. Hardee Power Partners Limited, and GTCR Golder Rauner, LLC

[Docket No. EC04–56–000]

Take notice that on January 22, 2004, Hardee Power Partners Limited (HPP) and GTCR Golder Rauner, LLC (GTCR) (collectively, Applicants), tendered for filing with the Commission, pursuant to section 203 of the Federal Power Act and part 33 of the Commission's regulations, an application for authorization to reorganize GTCR's interest in HPP. Pursuant to 18 CFR 33.9 (2003), the Applicants seek privileged treatment for Exhibites C–2 and C–4 of the Application.

Comment Date: February 12, 2004.

2. New York Municipal Power Agency v. New York State Electric & Gas Corporation

[Docket No. EL04–56–000]

On January 16, 2004, the New York Municipal Power Authority, on behalf of its affected member municipal systems (NYMPA) filed a complaint concerning certain elements of the Transmission Service Charge currently assessed by the New York State Electric & Gas Corporation (NYSEG) under Attachment H of the Open Access Transmission Tariff of the New York Independent System Operator, Inc. A notice of complaint was issued on January 20, 2004. Subsequently, on January 20, 2004, NYMPA and NYSEG filed a proposed stipulation and agreement that would, if approved by the Commission, resolve all issues raised by the complaint.

NYMPA and NYSEG also filed a joint motion requesting that the Commission suspend the time for filing answers to the original complaint which the issuance of this superceding notice resolves.

Comment Date: February 9, 2004.

3. Denver City Energy Associates, LP

[Docket No. ER97–4084–009]

Take notice that on January 14, 2004, Denver City Energy Associates, L.P. submitted a compliance filing in response to the Commission's Order issued December 15, 2003, in Docket No. ER97–4084–000 to incorporate the Market behavior rules adopted by the Commission in the November 17, 2003, Order Amending Market-based Rate Tariffs and Authorizations, in Docket Nos. EL01–118–000 and 001.

Comment Date: January 30, 2004.

4. Camden Cogen, LP, Capital District Energy Center, Cogeneration Associates, Cogen Technologies NJ Venture, Front Range Power Company, LLC, Pawtucket Power Associates Limited Partnership, and Vandolah Power Company, LLC

[Docket Nos. ER01–2756–003, ER02–579–002, ER02–1486–002, ER02–1173–002, ER02–580–002, and ER02–1336–002]

Take notice that on January 12 and 14, 2004, the above referenced companies filed amendments to their filings of December 17, 2003, that were submitted in compliance with Commission's Order issued November 17, 2003, in Docket Nos. EL01–118–000 and 001.

Comment Date: January 30, 2004.

5. California Independent System Operator Corporation

[Docket No. ER03–942–003]

Take notice that on January 15, 2004, the California Independent System Operator Corporation (ISO) submitted a filing to comply with the order issued in Docket No. ER03–942–000 on December 15, 2003, 105 FERC 61,284. The ISO states that the compliance filing has been served on all parties to these proceedings.

Comment Date: February 5, 2004.

6. MxEnergy Electric Inc.

[Docket No. ER04–170–002]

Take notice that on January 15, 2004, MxEnergy Electric Inc. submitted a compliance filing in response to the Commission's January 12, 2004, Order in Docket Nos. ER04–170–000 and 001 to incorporate the market behavior rules adopted by the Commission in the November 17, 2003, Order Amending Market-based Rate Tariffs and Authorizations, in Docket Nos. EL01–118–000 and 001.

Comment Date: January 30, 2004.

7. Great Bay Hydro Corporation

[Docket No. ER04–183–001]

Take notice that on January 16, 2004, Great Bay Hydro Corporation (Great Bay Hydro) tendered for filing a revised market-based rate tariff in compliance with the Commission's December 19, 2003, Letter Order in Docket No. ER04–183–000 to incorporate the market behavior rules adopted by the Commission in the November 17, 2003, Order Amending Market-based Rate Tariffs and Authorizations in Docket Nos. EL01–118–000 and 001. Great Bay Hydro requests an effective date of December 17, 2003.

Great Bay Hydro states that a copy of the filing was served on the New Hampshire Public Utilities Commission.

Comment Date: January 30, 2004.

8. California Independent System Operator Corporation

[Docket No. ER04–286–001]

Take notice that on January 16, 2004, the California Independent System Operator Corporation (ISO) submitted an informational filing in accordance with Article IX, section B of the offer of settlement filed in Docket Nos. ER98–441–000, *et al.*, on April 2, 1999, concerning a notice the ISO received from an RMR Owner on December 30, 2003, stating that the RMR Owner wished to retract a notice that the ISO had submitted in the December 12, 2003, filing submitted in the captioned proceeding. ISO states that as required by Article IX, section B of the Stipulation and Agreement approved by the Commission on May 28, 1999, California Independent System Operator Corporation, 87 FERC ¶ 61,250, the ISO has provided notice of the changes described in the December 30, 2003, notice (subject to the applicable Non-Disclosure and Confidentiality Agreement in the RMR Contract) to the designated RMR contact persons at the California Agencies, the applicable responsible utility, and the relevant RMR Owner.

Comment Date: February 6, 2004.

9. International Transmission Company

[Docket Nos. ER03–343–003 and EC03–40–000]

Take notice that on December 17, 2003, International Transmission Company (ITC) filed a status report with the Commission. ITC states that in approving the transfer of interstate transmission assets from Detroit Edison Company (Detroit Edison) to ITC in an Order issued February 20, 2003, in Docket Nos. ER03–343–000 and EC03–40–000, the Commission limited the term of ITC's service level agreements with Detroit Edison to one year (March 1, 2003, through February 29, 2004) and otherwise conditioned the replacement of the service level agreements. ITC states that the purpose of the instant filing is to report to the Commission that ITC will replace the service level agreements with internal company resources and new contracts with independent third parties on or before the March 1, 2004, deadline.

ITC states that it has served copies of this filing upon the parties on the official service list and the Michigan Public Service Commission. ITC further states that it also filed confidential materials with the Commission under separate cover in this filing and it will make the confidential materials available to any party upon the execution of a confidentiality agreement.

Comment Date: February 3, 2004.

10. Wisconsin Public Service Corporation

[Docket No. ER04–354–001]

Take notice that on January 15, 2004, Wisconsin Public Service Corporation (WPSC) tendered for filing a redesignated revised rate schedule sheet (Redesignated Revised Sheet) in Exhibit G to WPSC's Second Revised Rate Schedule FERC No. 51 with the City of Marshfield. WPSC states the Redesignated Revised Sheet has been modified to reflect the appropriate designations.

WPSC respectfully requests that the Commission allow the Redesignated Revised Sheet to become effective on January 1, 2004, the same date WPSC requested in its December 31, 2003, filing in this proceeding.

WPSC further states that copies of this filing have been served on the Commission's official service list, the City of Marshfield and the Public Service Commission of Wisconsin.

Comment Date: February 5, 2004.

11. PJM Interconnection, LLC

[Docket No. ER04–367–001]

Take notice that on January 12, 2004, PJM Interconnection, LLC (PJM) and Commonwealth Edison Company and Commonwealth Edison Company of Indiana, Inc. (ComEd) filed four corrected revised sheets to the PJM Open Access Transmission tariff (Tariff) to replace sheets submitted with their December 31, 2003, filing in Docket No. ER04–367–000.

PJM and ComEd stated that, consistent with the effective date requested in the December 31 filing, they request that the submitted sheets become effective on May 1, 2004.

PJM states that copies of this filing were served on all PJM members, the utility regulatory commissions in the PJM region, and all persons on the service list for this proceeding.

Comment Date: February 2, 2004.

12. Southern California Edison Company

[Docket No. ER04–409–000]

Take notice that on January 16, 2004, Southern California Edison Company (SCE) tendered for filing a revision to its Transmission Owner Tariff, FERC Electric Tariff, Second Revised Volume No. 6, Appendix III to reflect the annual update of the Transmission Access Charge Balancing Account Adjustment. SCE requests that the filing be made effective February 1, 2004.

SCE states that copies of this filing were served upon the Public Utilities Commission of the State of California, the California Independent System Operator, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and the Cities of Anaheim, Azusa, Banning, Reiverside, and Vermon, California.

Comment Date: February 6, 2004.

Standard Paragraph

Any person desiring to intervene or to protest this filing should file with the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, in accordance with rules 211 and 214 of the Commission's rules of practice and procedure (18 CFR 385.211 and 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. All such motions or protests should be filed on or before the comment date, and, to the extent applicable, must be served on the applicant and on any other person designated on the official service list. This filing is available for review at the Commission or may be viewed on the Commission's Web site at *http://www.ferc.gov*, using the "FERRIS" link. Enter the docket number excluding the last three digits in the docket number filed to access the document. For assistance, call (202) 502–8222 or TTY, (202) 502–8659. Protests and interventions may be filed electronically via the Internet in lieu of paper; *see* 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site under the "e-Filing" link. The Commission strongly encourages electronic filings.

Magalie R. Salas,

Secretary.

[FR Doc. E4–156 Filed 1–29–04; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project Nos. 2516–026–WV, and 2517–012–WV]

Allegheny Energy Supply Company, LLC; Dam No. 4 Hydro Station Project and Dam No. 5 Hydro Station Project; Notice of Availability of Environmental Assessment

January 23, 2004.

In accordance with the National Environmental Policy Act of 1969 and the Federal Energy Regulatory Commission's (Commission) regulations, 18 CFR part 380 (Order No. 486; 52 FR 47897), the staff of the Office of Energy Projects (staff) has reviewed the applications for a new license for the Dam No. 4 Hydro Station Project No. 2516 and a subsequent license for the Dam No. 5 Hydro Station Project No. 2517, located on the Potomac River in West Virginia, and has prepared an Environmental Assessment (EA) for the projects. The Dam No. 4 Hydro Station Project is located near the town of Shepherdstown, West Virginia, in Berkeley and Jefferson Counties. The Dam No. 5 Hydro Station Project is located near the town of Hedgesville, in Berkeley County. The project dams and reservoirs are owned by the United States and operated by the National Park Service.

The EA contains the staff's analysis of the potential environmental impacts of the projects and concludes that licensing the projects, with appropriate environmental protective measures, would not constitute major Federal actions that would significantly affect the quality of the human environment.

A copy of the EA is available for review at the Commission in the Public Reference Room, located at 888 First Street, NE., Room 2A, Washington, DC 20426, or may be viewed on the Commission's Web site at *http://www.ferc.gov* using the "eLibrary" link (formerly, "FERRIS" link). Enter the docket number excluding the last three digits in the docket number field to access the document. For assistance, contact FERC Online Support at *FERCOnlineSupport@ferc.gov* or toll-free at 1–866–208–3676, or for TTY, (202) 502–8659.

You may also register online at *http://www.ferc.gov/esubscribenow.htm* to be notified via email of new filings and issuances related to this or other pending projects.

Because staff intends this to be the only EA prepared for these projects, any comments on this EA should be filed within 30 days from the date of this notice and should be addressed to: Magalie R. Salas, Secretary, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426. Please affix "Dam No. 4 Project No. 2516–026" or "Dam No. 5 Project No. 2517–012" to all comments. For further information, contact Peter Leitzke at (202) 502–6059 or *peter.leitzke@ferc.gov*.

Comments may be filed electronically via the Internet in lieu of paper. The Commission strongly encourages electronic filings. *See* 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site *http://www.ferc.gov* under the "e-Filing" link.

Magalie R. Salas,

Secretary.

[FR Doc. E4–161 Filed 1–29–04; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 2233–043 Oregon]

Portland General Electric Company; Notice of Availability of Draft Environmental Assessment

January 23, 2004.

In accordance with the National Environmental Policy Act of 1969 and the Federal Energy Regulatory Commission's (Commission) regulations, 18 CFR part 380 (Order No. 486, 52 F.R. 47897), the Office of Energy Projects has reviewed the application for license for the Willamette Falls Hydroelectric Project, located on the Willamette River near Oregon City, Oregon, and has prepared a Draft Environmental Assessment (DEA) for the project.

The DEA contains the staff's analysis of the potential environmental impacts of the project and concludes that licensing the project, with appropriate environmental protective measures, would not constitute a major Federal action that would significantly affect the quality of the human environment.

A copy of the DEA is available for review at the Commission in the Public Reference Room or may be viewed on the Commission's Web site at *http://www.ferc.gov* using the "eLibrary" link. Enter the docket number P–2233 to access the document. For assistance, contact FERC Online Support at *FERCOnlineSupport@ferc.gov* or toll-free at 1–866–208–3676, or for TTY, (202) 502–8659.

You may also register online at *http://www.ferc.gov/docs-filing/esubscription.asp* to be notified via email of new filings and issuances related to this or other pending projects. For assistance, contact FERC Online Support.

Any comments should be filed within 45 days from the date of this notice and should be addressed to Magalie R. Salas, Secretary, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426. Please affix Project No. P–2233 to all comments. Comments may be filed electronically via the Internet in lieu of paper. The Commission strongly encourages electronic filings. See 18 CFR 385.2001(a) (1)(iii) and the instructions on the Commission's Web site (*http://www.ferc.gov*) under the "e-Filing" link.

FOR FURTHER INFORMATION CONTACT: John Blair (202) 502–6092.

Magalie R. Salas,

Secretary.

[FR Doc. E4–160 Filed 01–29–04; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 2213–009–Washington]

Public Utility District No. 1 of Cowlitz County; Notice of Availability of Draft Environmental Assessment

January 23, 2004.

In accordance with the National Environmental Policy Act of 1969, as amended, and the Federal Energy Regulatory Commission's (Commission) regulations (18 CFR Part 380), Commission staff have reviewed plans, filed September 3, 2003 and supplemented November 17, 2003 and December 10, 2003, to repair the Swift No. 2 Project's power canal, tailrace, and switchyard. The project is located on the North Fork Lewis River in Washington.

The project licensee (Public Utility District No. 1 of Cowlitz County) proposes to repair and reconstruct the damage to the Swift No. 2 Project's power canal, tailrace, and switchyard following an April 21, 2002 canal breach and washout. Under Section 10(c) of the FPA, the licensee is obligated to maintain the project works in a good state of repair. The licensee has proposed a reasonable schedule for the work. In the draft EA, Commission staff has analyzed the probable environmental effects of the proposed work and has concluded that approval, with appropriate environmental measures, would not constitute a major Federal action significantly affecting the quality of the human environment.

Copies of the draft EA are available for review in Public Reference Room 2–A of the Commission's offices at 888 First Street, NE., Washington, DC. The draft EA also may be viewed on the Commission's Internet Web site (*http://www.ferc.gov*) using the "eLibrary" link. Additional information about the project is available from the Commission's Office of External Affairs, at (202) 502–6088 or on the Commission's Web site using the eLibrary link. Click on the eLibrary link, enter the docket number excluding the last three digits in the Docket Number field. Be sure you have selected an appropriate date range. For assistance, contact *FERCOnlineSupport@ferc.gov*or call toll-free at (866) 208–3676, or for TTY contact (202) 502–8659.

Anyone may file comments on the draft EA. The public, federal and state resource agencies are encouraged to provide comments. Any comments on the draft EA should be filed within 15 days of the date of this notice and should be addressed to: Magalie R. Salas, Secretary, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426. Please reference "Swift No. 2 Project, FERC Project No. 2213–009" on all comments. Comments may be filed electronically via the Internet in lieu of paper. See 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site under the "e-Filing" link.

Magalie R. Salas,

Secretary.

[FR Doc. E4–159 Filed 1–29–04; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. CP93–541–013]

Young Gas Storage Company, Ltd.; Notice of Intent to Prepare an Environmental Assessment for the Proposed Young Storage Project and Request for Comments on Environmental Issues

January 23, 2004.

The staff of the Federal Energy Regulatory Commission (FERC or Commission) will prepare an environmental assessment (EA) that will discuss the environmental impacts of the Young Storage Project involving construction and operation of facilities by Young Gas Storage Company, Ltd (Young) in Morgan County, Colorado.[1] These facilities would consist of:

- 3 horizontally drilled injection/withdrawal wells (Wells 43, 44, and 45);
- Facilities associated with each well that include a surface wellhead and associated filters/separators, orifice meter, catalytic heater, and methanol injection/storage tanks with concrete footers;
- 600 feet of 6-inch-diameter steel gas pipeline;
- 1,090 feet of 4-inch-diameter steel gas pipeline;
- 1,090 feet of 2-inch-diameter poly instrument pipeline; and
- 1,090 feet of 2-inch-diameter fiberglass drainline pipeline.

This EA will be used by the Commission in its decision-making process to determine whether the project is in the public convenience and necessity.

If you are a landowner receiving this notice, you may be contacted by a pipeline company representative about the acquisition of an easement to construct, operate, and maintain the proposed facilities. The pipeline company would seek to negotiate a mutually acceptable agreement. However, if the project is approved by the Commission, that approval conveys with it the right of eminent domain. Therefore, if easement negotiations fail to produce an agreement, the pipeline company could initiate condemnation proceedings in accordance with State law.

A fact sheet prepared by the FERC entitled "An Interstate Natural Gas Facility On My Land? What Do I Need To Know?" was attached to the project notice Young provided to landowners. This fact sheet addresses a number of typically asked questions, including the use of eminent domain and how to participate in the Commission's proceedings. It is available for viewing on the FERC Internet Web site (*http://www.ferc.gov*).

Summary of the Proposed Project

Young has analyzed the operation of the Young Storage Field and determined that water has been displaced and produced from the storage field during the 8 years of its operation. This has increased the pore space available for gas storage. The increased space has caused storage pressures to decrease below the pressure contemplated when the field was designed. The storage field has also expanded into areas that cannot be effectively drained by the existing wells. The reduced pressure and reservoir expansion have reduced deliverability from the field.

Young wants to drill there injection/withdrawal wells to better access certain areas within the existing Young Storage Field. It would also construct pipeline and related facilities to connect these new wells to its existing storage field pipeline system. The storage capacity and withdrawal capability of the Young Storage Field would not be increased above the presently certificated volumes (10 billion cubic feet and 198,813 thousand cubic feet per day, respectively) by construction and operation of the proposed facilities. Young also proposes to expand the protection zone for the storage field.

[1] Young's application was filed with the Commission under section 7 of the Natural Gas Act and part 157 of the Commission's regulations.

Young would also reclassify two existing injection/withdrawal wells (Wells 24 and 39) as observation wells.

Young also proposes to conduct a reservoir testing program to evaluate the possibility of increasing gas deliverability from the storage field as it drills the proposed new injection/withdrawal wells.

The location of the project facilities is shown in appendix 1.[2]

Land Requirements for Construction

Construction of the proposed facilities would require about 6.8 acres of land. Following construction, about 2.2 acres would be maintained for operation of the new facilities. The remaining 4.6 acres of land would be restored and allowed to revert to its former use.

The EA Process

The National Environmental Policy Act (NEPA) requires the Commission to take into account the environmental impacts that could result from an action whenever it considers the issuance of a Certificate of Public Convenience and Necessity. NEPA also requires us[3] to discover and address concerns the public may have about proposals. This process is referred to as "scoping". The main goal of the scoping process is to focus the analysis in the EA on the important environmental issues. By this notice of intent, the Commission requests public comments on the scope of the issues it will address in the EA. All comments received are considered during the preparation of the EA. State and local government representatives are encouraged to notify their constituents of this proposed action and encourage them to comment on their areas of concern.

The EA will discuss impacts that could occur as a result of the construction and operation of the proposed project under these general headings:

- Geology and soils;
- Land use;
- Ground water;
- Cultural resources;
- Vegetation and wildlife;
- Air quality and noise;
- Endangered and threatened species;
- Public safety.

We will not discuss impacts to the following resource areas since they are not present in the project area, or would not be affected by the proposed facilities.

- Surface water;
- Wetlands;
- Fisheries;
- Residential areas;
- Federal, State, or local parks, forests, trails, scenic highways, wild and scenic rivers, nature preserves, wildlife refuges, wilderness areas, game management areas, or other designated natural, recreational, or scenic areas registered as natural landmarks;
- Native American reservations, or
- Coastal zone management areas.

We will also evaluate possible alternatives to the proposed project or portions of the project, and make recommendations on how to lessen or avoid impacts on the various resource areas.

Our independent analysis of the issues will be in the EA. Depending on the comments received during the scoping process, the EA may be published and mailed to Federal, State, and local agencies, public interest groups, interested individuals, affected landowners, newspapers, libraries, and the Commission's official service list for this proceeding. A comment period will be allotted for review if the EA is published. We will consider all comments on the EA before we make our recommendations to the Commission.

To ensure your comments are considered, please carefully follow the instructions in the public participation section below.

Currently Identified Environmental Issues

We have already identified several issues that we think deserve attention based on a preliminary review of the proposed facilities and the environmental information provided by Young. This preliminary list of issues may be changed based on your comments and our analysis.

- A total of 6.77 acres of agricultural land and pasture would be affected by the project.
- Three horizontally drilled wells would be constructed.

Public Participation

You can make a difference by providing us with your specific comments or concerns about the project. By becoming a commentor, your concerns will be addressed in the EA and considered by the Commission. You should focus on the potential environmental effects of the proposal, alternatives to the proposal including alternative well locations and pipeline routes, and measures to avoid or lessen environmental impact. The more specific your comments, the more useful they will be. Please carefully follow these instructions to ensure that your comments are received in time and properly recorded:

- Send an original and two copies of your letter to: Magalie R. Salas, Secretary, Federal Energy Regulatory Commission, 888 First St., NE., Room 1A, Washington, DC 20426.
- Label one copy of the comments for the attention of Gas Branch 2.
- Reference Docket No. CP93–541–013.
- Mail your comments so that they will be received in Washington, DC on or before February 23, 2004.

Please note that we are continuing to experience delays in mail deliveries from the U.S. Postal Service. As a result, we will include all comments that we receive within a reasonable time frame in our environmental analysis of this project. However, the Commission strongly encourages electronic filing of any comments or interventions or protests to this proceeding. *See* 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site at *http://www.ferc.gov* under the "e-Filing" link and the link to the User's Guide. Before you can file comments you will need to create a free account which can be created on-line.

We may mail the EA for comment. If you are interested in receiving it, please return the Information Request (appendix 4). If you do not return the Information Request, you will be taken off the mailing list.

Becoming an Intervenor

In addition to involvement in the EA scoping process, you may want to become an official party to the proceeding known as an "intervenor". Intervenors play a more formal role in the process. Among other things, intervenors have the right to receive copies of case-related Commission documents and filings by other intervenors. Likewise, each intervenor must provide 14 copies of its filings to the Secretary of the Commission and must send a copy of its filings to all other parties on the Commission's service list for this proceeding. If you want to become an intervenor you must file a motion to intervene according to rule 214 of the Commission(s rules of practice and procedure (18 CFR 385.214) (*see* appendix 2).[4] Only

[2] The appendices referenced in this notice are not being printed in the **Federal Register**. Copies are available on the Commission's Internet Web site (*http://www.ferc.gov*) at the "eLibrary" link or from the Commission's Public Reference and Files Maintenance Branch at (202) 502–8371. For instructions on connecting to eLibrary refer to the last page of this notice.

[3] "We", "us", and "our" refer to the environmental staff of the Office of Energy Projects (OEP).

[4] Interventions may also be filed electronically via the Internet in lieu of paper. *See* the previous discussion on filing comments electronically.

intervenors have the right to seek rehearing of the Commission's decision.

Affected landowners and parties with environmental concerns may be granted intervenor status upon showing good cause by stating that they have a clear and direct interest in this proceeding which would not be adequately represented by any other parties. You do not need intervenor status to have your environmental comments considered.

Environmental Mailing List

An effort is being made to send this notice to all individuals, organizations, and government entities interested in and/or potentially affected by the proposed project. This includes all landowners who are potential right-of-way grantors, whose property may be used temporarily for project purposes, or who own homes within distances defined in the Commission's regulations of certain aboveground facilities. By this notice we are also asking governmental agencies, especially those in appendix 3, to express their interest in becoming cooperating agencies for the preparation of the EA.

Additional Information

Additional information about the project is available from the Commission's Office of External Affairs, at 1–866–208–FERC or on the FERC Internet Web site (*http://www.ferc.gov*) using the eLibrary link. Click on the eLibrary link, click on "General Search" and enter the docket number excluding the last three digits in the Docket Number field. Be sure you have selected an appropriate date range. For assistance with eLibrary, the eLibrary helpline can be reached at 1–866–208–3676, TTY (202) 502–8659, or at *FERConlinesupport@ferc.gov*. The eLibrary link on the FERC Internet Web site also provides access to the texts of formal documents issued by the Commission, such as orders, notices, and rulemakings.

In addition, the Commission now offers a free service called eSubscription which allows you to keep track of all formal issuances and submittals in specific dockets. This can reduce the amount of time you spend researching proceedings by automatically providing you with notification of these filings, document summaries and direct links to the documents. Go to *http://www.ferc.gov/esubscribenow.htm*.

Finally, public meetings or site visits will be posted on the Commission's calendar located at *http://www.ferc.gov/Event Calendar/EventsList.aspx* along with other related information.

Magalie R. Salas,
Secretary.
[FR Doc. E4–163 Filed 1–29–04; 8:45 am]
BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 2207–009]

Mosinee Paper Corporation ; Notice of Settlement Agreement and Soliciting Comments

January 22, 2004.

Take notice that the following settlement agreement has been filed with the Commission and is available for public inspection.

a. *Type of Application*: Settlement agreement.

b. *Project No.*: 2207–009.

c. *Date Filed*: January 7, 2004.

d. *Applicant*: Mosinee Paper Corporation.

e. *Name of Project*: Mosinee Hydroelectric Project.

f. *Location*: On the Wisconsin River in the town of Mosinee, Marathon County, Wisconsin. The project does not utilize Federal lands.

g. *Filed Pursuant to*: Rule 602 of the Commission's rules of practice and procedures, 18 CFR 385.602.

h. *Applicant Contact*: Mr. Jeff Verdoorn, Mosinee Paper Corporation, 100 Main Street, Mosinee, Wisconsin 54455 (715) 693–2111.

i. *FERC Contact*: Michael Spencer, *michael.spencer@ferc.gov*, (202) 502–6093.

j. *Deadline for Filing Comments*: The deadline for filing comments on the Settlement Agreement is 20 days from the date of this notice. The deadline for filing reply comments is 30 days from the date of this notice. All documents (original and eight copies) should be filed with: Magalie R. Salas, Secretary, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426.

Under the Commission(s rules of practice, intervenors in the relicensing proceeding filing documents with the Commission must serve a copy of that document on each person on the official service list for the project. Further, if an intervenor files comments or documents with the Commission relating to the merits of an issue that may affect the responsibilities of a particular resource agency, they must also serve a copy of the document on that resource agency.

Comments may be filed electronically via the Internet in lieu of paper. *See* 18 CFR 385.2001(a)(1)(iii) and the instructions of the Commission's Web site (*http://www.ferc.gov*) under the "e-filing" link.

k. Mosinee Paper Corporation filed the final Settlement Agreement on behalf of itself and the State of Wisconsin. The purpose of the Settlement Agreement is to resolve, among the signatories, all water resource related issues of Mosinee Paper Corporation pending application for new license for the Mosinee Hydroelectric Project. The relicensing issues resolved through the settlement include requirements for flashboards, recreation issues, operations, fish passage and fish protection, minimum flows, headwater and tailwater elevation monitoring, and land management practices.

l. A copy of the Settlement Agreement is available for review at the Commission in the Public Reference Room or may be viewed on the Commission's Web site at *http://www.ferc.gov*, using the eLibrary link. Enter the docket number, excluding the last three digits in the docket number field to access the document. For assistance, contact FERC Online Support at *FERCOnlineSupport@ferc.gov* or toll-free at 1–866–208–3676, or for TTY, (202) 502–8659. A copy is also available for inspection and reproduction at the address in item h above.

You may also register online at *http://www.ferc.gov/esubscribenow.htm* to be notified via e-mail of new filings and issuances related to this or other pending projects. For assistance, contact FERC Online Support. To view upcoming FERC events, go to *www.ferc.gov* and click on "View Entire Calendar".

Magalie R. Salas,
Secretary.
[FR Doc. E4–149 Filed 1–29–04; 8:45 am]
BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Notice of Application for Non-Project Use of Project Lands and Waters and Soliciting Comments, Motions To Intervene, and Protests

January 22, 2004.

Take notice that the following application has been filed with the Commission and is available for public inspection:

a. *Application Type:* Non-project use of project lands and waters.
b. *Project No.:* 2503–077.
c. *Date Filed:* October 2, 2003.
d. *Applicant:* Duke Power, a Division of Duke Energy Corporation.
e. *Name of Project:* Keowee-Jocassee Hydroelectric Project.
f. *Location:* On Lake Keowee at Water's Edge Subdivision in Oconee County, South Carolina.
g. *Filed Pursuant to:* Federal Power Act, 16 U.S.C. 791 (a) 825(r) and 799 and 801.
h. *Applicant Contact:* Mr. Joe Hall, Lake Management Representative, Duke Energy Corporation, P.O. Box 1006, Charlotte, NC, 28201–1006, (704) 382–8576.
i. *FERC Contacts:* Any questions on this notice should be addressed to Ms. Jean Potvin at (202) 502–8928, or e-mail address: *jean.potvin@ferc.gov.*
j. *Deadline for filing comments and or motions:* February 23, 2004.

All documents (original and eight copies) should be filed with: Ms. Magalie R. Salas, Secretary, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426. Please include the project number (P–2503–077) on any comments or motions filed. Comments, protests, and interventions may be filed electronically via the internet in lieu of paper. *See*, 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site under the "e-Filing" link. The Commission strongly encourages e-filings.

k. *Description of Request:* Duke Power is requesting Commission approval to lease 0.908 acre of land within the project boundary to Mr. Danny Cisson for a commercial/residential marina. The marina will consist of 2 cluster docks with 28 boat slips and 8 end ties for a total of 36 boat docking locations, a boat ramp with courtesy dock, and shoreline stabilization for access to the reservoir for residents of the Water's Edge Subdivision located in Oconee County, South Carolina. The docks will be constructed of high quality treated wood, steel, and encapsulated Styrofoam (Formex) for floatation. The docks will be constructed off site and floated into place. The concrete boat launching ramp will be 12 feet in width and 120 feet in length and constructed of 6 inch thick welded wire mesh reinforced concrete. The shoreline stabilization will consist of 436 linear feet of rip rap material. Approximately 50 cubic yards of fill material and approximately 705 cubic yards of rip rap will be deposited around the slip areas to provide for shoreline stabilization by either truck or barge.

l. *Location of the Applications:* The filings are available for review at the Commission in the Public Reference Room, located at 888 First Street, NE., Room 2A, Washington, DC 20426, or may be viewed on the Commission's Web site at *http://www.ferc.gov* using the "eLibrary" link. Enter the docket number excluding the last three digits in the docket number field to access the document. For assistance, please call the Helpline at (866) 208–3676 or contact *FERCOnLineSupport@ferc.gov.* For TTY, contact (202) 502–8659.

m. Individuals desiring to be included on the Commission's mailing list should so indicate by writing to the Secretary of the Commission.

n. *Comments, Protests, or Motions to Intervene*—Anyone may submit comments, a protest, or a motion to intervene in accordance with the requirements of rules of practice and procedure, 18 CFR 385.210, .211, .214. In determining the appropriate action to take, the Commission will consider all protests or other comments filed, but only those who file a motion to intervene in accordance with the Commission's Rules may become a party to the proceeding. Any comments, protests, or motions to intervene must be received on or before the specified comment date for the particular application.

o. *Filing and Service of Responsive Documents*—Any filings must bear in all capital letters the title "COMMENTS", "RECOMMENDATIONS FOR TERMS AND CONDITIONS", "PROTEST", OR "MOTION TO INTERVENE", as applicable, and the Project Number of the particular application to which the filing refers. A copy of any motion to intervene must also be served upon each representative of the Applicant specified in the particular application.

p. *Agency Comments*—Federal, State, and local agencies are invited to file comments on the described applications. A copy of the applications may be obtained by agencies directly from the Applicant. If an agency does not file comments within the time specified for filing comments, it will be presumed to have no comments. One copy of an agency's comments must also be sent to the Applicant's representatives.

q. Comments, protests and interventions may be filed electronically via the Internet in lieu of paper. *See*, 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site at *http://www.ferc.gov* under the "e-Filing" link.

Magalie R. Salas,
Secretary.
[FR Doc. E4–150 Filed 1–29–04; 8:45 am]
BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. PF04–1–000]

Golden Pass LNG LP and Golden Pass Pipeline LP; Notice of Meeting Attendance

January 23, 2004.

The staff of the Federal Energy Regulatory Commission (FERC) will attend Golden Pass LNG LP and Golden Pass Pipeline LP's Open House meetings for the Golden Pass LNG and Pipeline Project. The meetings will be held from 5 to 7 p.m. at the following locations and on the identified dates:

January 27, 2004

Sabine Pass School, 5641 S. Gulfway Drive, Sabine Pass, Texas.

January 28, 2004

Carl A. Parker Multi-Purpose Building, Lamar University State College, 1800 Lake Shore Drive, Port Arthur, Texas.

February 3, 2004

VFW Hall, Starks, Louisiana.

We will be conducting a site visit of the project on Wednesday, January 28, 2004. We will meet at 8 a.m. at Skeeter's Restaurant, 5553 Dowling Road, Sabine Pass, Texas. We will view various portions of the project by traveling northward from the meeting point through Jefferson, Orange, and Newton Counties, Texas, and Calcasieu Parish, Louisiana. Interested persons must provide their own transportation.

For additional information about these meetings, please contact Karen Bailey, ExxonMobil, 281–654–7821.

Any interested persons may attend.

Magalie R. Salas,
Secretary.
[FR Doc. E4–162 Filed 1–29–04; 8:45 am]
BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Notice of FERC Staff Attendance at Meeting of Board of Directors of Southwest Power Pool

January 22, 2004.

The Federal Energy Regulatory Commission hereby gives notice that members of its staff will attend the January 27, 2004, meeting of the Board of Directors of the Southwest Power Pool (SPP). The staff's attendance is part of the Commission's ongoing outreach efforts.

The discussions may address matters at issue in the following proceedings:

Docket No. RM01–12–000, *Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design*; and

Docket Nos. RT04–1–000 and ER04–48–000, *Southwest Power Pool, Inc.*

The meeting will take place on January 27, 2004, and is expected to begin at approximately 10 a.m. The meeting will take place at the Marriott New Orleans, 555 Canal Street, New Orleans, LA 70130. The meeting is open to the public.

For more information, contact Tony Ingram, Office of Markets, Tariffs and Rates, Federal Energy Regulatory Commission at (202) 502–8938 or *tony.ingram@ferc.gov*.

Magalie R. Salas,
Secretary.
[FR Doc. E4–148 Filed 1–29–04; 8:45 am]
BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. RM98–1–000]

Records Governing Off-the Record Communications; Public Notice

January 23, 2004.

This constitutes notice, in accordance with 18 CFR 385.2201(b), of the receipt of exempt and prohibited off-the-record communications.

Order No. 607 (64 FR 51222, September 22, 1999) requires Commission decisional employees, who make or receive an exempt or prohibited off-the-record communication relevant to the merit's of a contested on-the-record proceeding, to deliver a copy of the communication, if written, or a summary of the substance of any oral communication, to the Secretary.

Prohibited communications will be included in a public, non-decisional file associated with, but not a part of, the decisional record of the proceeding. Unless the Commission determines that the prohibited communication and any responses thereto should become a part of the decisional record, the prohibited off-the-record communication will not be considered by the Commission in reaching its decision. Parties to a proceeding may seek the opportunity to respond to any facts or contentions made in a prohibited off-the-record communication, and may request that the Commission place the prohibited communication and responses thereto in the decisional record. The Commission will grant such a request only when it determines that fairness so requires. Any person identified below as having made a prohibited off-the-record communication shall serve the document on all parties listed on the official service list for the applicable proceeding in accordance with Rule 2010, 18 CFR 385.2010.

Exempt off-the-record communications will be included in the decisional record of the proceeding, unless the communication was with a cooperating agency as described by 40 CFR 1501.6, made under 18 CFR 385.2201(e)(1)(v).

The following is a list of prohibited and exempt communications recently received in the Office of the Secretary. The communications listed are grouped by docket numbers. These filings are available for review at the Commission in the Public Reference Room or may be viewed on the Commission's Web site at *http://www.ferc.gov* using the eLibrary (FERRIS) link. Enter the docket number excluding the last three digits in the docket number field to access the document. For Assistance, please contact FERC, Online Support at *FERCOnlineSupport@ferc.gov* or toll free at (866) 208–3676, or for TTY, contact (202) 502–8659.

Exempt

Docket number	Date filed	Presenter or requester
1. CP01–409–000.	1–13–04	Charles Brown/James Elbling
2. ER04–316–000.	1–14–04	Hon. Christopher Cox
3. CP03–75–000.	1–21–04	Miles M. Croom
4. CP04–4–000.	1–22–04	Shannon Jones/Kerri Roberts/Helen Hight

Magalie R. Salas,
Secretary.
[FR Doc. E4–157 Filed 1–29–04; 8:45 am]
BILLING CODE 6717–01–P

ENVIRONMENTAL PROTECTION AGENCY

[OECA–2003–0029; FRL–7615–9]

Agency Information Collection Activities; Submission for OMB Review and Approval; Comment Request; NESHAP for Mineral Wool Production, EPA ICR Number 1799.03, OMB Number 2060–0362

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: In compliance with the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*), this document announces that an Information Collection Request (ICR) has been forwarded to the Office of Management and Budget (OMB) for review and approval. This is a request to renew an existing approved collection. This ICR is scheduled to expire on January 31, 2004. Under OMB regulations, the Agency may continue to conduct or sponsor the collection of information while this submission is pending at OMB. This ICR describes the nature of the information collection and its estimated burden and cost.

DATES: Additional comments may be submitted on or before March 1, 2004.

ADDRESSES: Submit your comments, referencing docket ID number OECA–2003–0029, to (1) EPA online using EDOCKET (our preferred method), by email to *docket.oeca@epa.gov,* or by mail to: EPA Docket Center (EPA/DC), Enforcement and Compliance Docket and Information Center, Mail Code 2201T, 1200 Pennsylvania Avenue, NW., Washington, DC 20460, and (2) OMB at: Office of Information and Regulatory Affairs, Office of Management and Budget (OMB), Attention: Desk Officer for EPA, 725 17th Street, NW., Washington, DC 20503.

FOR FURTHER INFORMATION CONTACT: Gregory Fried, Compliance Assessment and Media Programs Division, Office of Compliance, Mail Code 2223A, Environmental Protection Agency, 1200 Pennsylvania Avenue, NW., Washington, DC 20460; telephone number: (202) 564–7016; fax number: (202) 564–0050; e-mail address: *fried.gregory@epa.gov.*

SUPPLEMENTARY INFORMATION: EPA has submitted the following ICR to OMB for review and approval according to the procedures prescribed in 5 CFR 1320.12. On May 19, 2003 (68 FR 27059), EPA sought comments on this ICR pursuant to 5 CFR 1320.8(d). EPA received no relevant comments.

EPA has established a public docket for this ICR under Docket ID No. OECA–2003–0029, which is available for public viewing at the Enforcement and Compliance Docket and Information Center in the EPA Docket Center (EPA/DC), EPA West, Room B102, 1301 Constitution Ave., NW., Washington, DC. The EPA Docket Center Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Reading Room is (202) 566–1744, and the telephone number for the Enforcement and Compliance Docket and Information Center is: (202) 566–1752. An electronic version of the public docket is available through EPA Dockets (EDOCKET) at http://www.epa.gov/edocket. Use EDOCKET to submit or view public comments, access the index listing of the contents of the public docket, and to access those documents in the public docket that are available electronically. When in the system, select "search," then key in the docket ID number identified above.

Any comments related to this ICR should be submitted to EPA and OMB within 30 days of this notice. EPA's policy is that public comments, whether submitted electronically or in paper, will be made available for public viewing in EDOCKET as EPA receives them and without change, unless the comment contains copyrighted material, Confidential Business Information (CBI), or other information whose public disclosure is restricted by statute. When EPA identifies a comment containing copyrighted material, EPA will provide a reference to that material in the version of the comment that is placed in EDOCKET. The entire printed comment, including the copyrighted material, will be available in the public docket. Although identified as an item in the official docket, information claimed as CBI, or whose disclosure is otherwise restricted by statute, is not included in the official public docket, and will not be available for public viewing in EDOCKET. For further information about the electronic docket, *see* EPA's **Federal Register** notice describing the electronic docket at 67 FR 38102 (May 31, 2002), or go to *http://www.epa.gov/edocket.*

Title: NESHAP for Mineral Wool Production (40 CFR Part 63, Subpart DDD).

Abstract: The Administrator has judged that particulate matter (PM) and hazardous air pollutant (HAP) emissions from mineral wool production plants cause or contribute to air pollution that may reasonably be anticipated to endanger public health or welfare. Owners/operators of mineral wool production plants subject to NESHAP for Mineral Wool Production (40 CFR part 63, subpart DDD) must provide notifications to EPA of construction, modification, startups, shut downs, date and results of initial performance tests and provide semiannual reports of excess emissions. Owners/operators of mineral wool production plants are required to install fabric filter bag leak detection systems and then initiate corrective action procedures in the event of an operating problem. Owners/operators of mineral wool production plants subject to NESHAP subpart DDD must also continuously monitor and record: (1) The operating temperature of each thermal incinerator; (2) cupola production (melt) rate; and (3) for each curing oven, the formaldehyde content of each binder formulation used to manufacture bonded products.

In order to ensure compliance with the standards promulgated to protect public health, adequate reporting and recordkeeping are necessary. In the absence of such information, enforcement personnel would be unable to determine whether the standards are being met on a continuous basis, as required by the Clean Air Act.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB Control Number. The OMB Control Numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9, and are identified on the form and/or instrument, if applicable.

Burden Statement: The annual public reporting and recordkeeping burden for this collection of information is estimated to average 126 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; 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.

Respondents/Affected Entities: Mineral Wool Production Facilities.

Estimated Number of Respondents: 12.

Frequency of Response: Initial and semiannual.

Estimated Total Annual Hour Burden: 3,018 hours.

Estimated Total Annual Costs: $199,906 which includes $0 annualized capital/startup costs, $9,000 annual O&M costs, and $190,906 labor costs.

Changes in the Estimates: There is decrease of 2,761 hours in the total estimated burden currently identified in the OMB Inventory of Approved ICR Burdens. This decrease is due to the fact that the compliance date of June 2, 2002, has passed and all existing facilities have already submitted all required notifications and completed all required performance testing. Therefore, the remaining burden on the industry is primarily the operation and maintenance of the control equipment (*e.g.*, baghouse leak detection systems) and the semiannual reporting.

Dated: January 22, 2004.

Doreen Sterling,

Acting Director, Collection Strategies Division.

[FR Doc. 04–1975 Filed 1–29–04; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[OECA–2003–0031; FRL–7615–8]

Agency Information Collection Activities; Submission for OMB Review and Approval; Comment Request; NESHAP for Off-Site Waste and Recovery Operations (40 CFR part 63, subpart DD), EPA ICR Number 1717.04, OMB Control Number 2060–0313

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: In compliance with the Paperwork Reduction Act, this document announces that an Information Collection Request (ICR) has been forwarded to the Office of Management and Budget (OMB) for review and approval. This is a request to renew an existing approved collection. This ICR is scheduled to expire on January 31, 2004. Under OMB regulations, the Agency may continue to conduct or sponsor the collection of information while this submission is pending at OMB. This ICR describes the nature of the information collection and its estimated burden and cost.

DATES: Additional comments may be submitted on or before March 1, 2004.

ADDRESSES: Submit your comments, referencing docket ID number OECA–2003–0031, to (1) EPA online using EDOCKET (our preferred method), by email to *docket.oeca@epa.gov*, or by mail to: EPA Docket Center, Environmental Protection Agency, Enforcement and Compliance Docket and Information Center, Mail Code 2201T, 1200 Pennsylvania Avenue, NW., Washington, DC 20460, and (2) OMB at: Office of Information and Regulatory Affairs, Office of Management and Budget (OMB), Attention: Desk Officer for EPA, 725 17th Street, NW., Washington, DC 20503.

FOR FURTHER INFORMATION CONTACT: Learia Williams, Compliance Assessment and Media Programs Division, Mail Code 2223A, Office of Compliance, Environmental Protection Agency, 1200 Pennsylvania Avenue, NW., Washington, DC 20460; telephone number: (202) 564–4113; fax number: (202) 564–0050; e-mail address: *williams.learia@epa.gov*.

SUPPLEMENTARY INFORMATION: EPA has submitted the following ICR to OMB for review and approval according to the procedures prescribed in 5 CFR 1320.12. On May 19, 2003 (68 FR 27059), EPA sought comments on this ICR pursuant to 5 CFR 1320.8(d). EPA received no comments.

EPA has established a public docket for this ICR under Docket ID Number OECA–2003–0031, which is available for public viewing at the Enforcement and Compliance Docket and Information Center in the EPA Docket Center (EPA/DC), EPA West, Room B102, 1301 Constitution Avenue, NW., Washington, DC. The EPA Docket Center Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Reading Room is (202) 566–1744, and the telephone number for the Enforcement and Compliance Docket and Information Center is (202) 566–1752. An electronic version of the public docket is available through EPA Dockets (EDOCKET) at *http://www.epa.gov/edocket*. Use EDOCKET to submit or view public comments, access the index listing of the contents of the public docket, and to access those documents in the public docket that are available electronically. When in the system, select "search," then key in the docket ID number identified above.

Any comments related to this ICR should be submitted to EPA and OMB within 30 days of this notice. EPA's policy is that public comments, whether submitted electronically or in paper, will be made available for public viewing in EDOCKET as EPA receives them and without change, unless the comment contains copyrighted material, Confidential Business Information (CBI), or other information whose public disclosure is restricted by statute. When EPA identifies a comment containing copyrighted material, EPA will provide a reference to that material in the version of the comment that is placed in EDOCKET. The entire printed comment, including the copyrighted material, will be available in the public docket. Although identified as an item in the official docket, information claimed as CBI, or whose disclosure is otherwise restricted by statute, is not included in the official public docket, and will not be available for public viewing in EDOCKET. For further information about the electronic docket, *see* EPA's **Federal Register** notice describing the electronic docket at 67 FR 38102 (May 31, 2002), or go to *http://www.epa.gov/edocket*.

Title: NESHAP for Off-Site Waste and Recovery Operations (40 CFR Part 63, Subpart DD) (Renewal).

Abstract: The National Emission Standards for Hazardous Air Pollutants (NESHAP), were proposed on October 13, 1994, and promulgated on July 1, 1996. These standards provide for control of hazardous air pollutants (HAP) emissions from selected facilities involved in waste management and recovery operations that are not subject to Federal air standards under other subparts in part 63 commencing construction, modification or reconstruction after the date of proposal if the facility is a "major source" of HAP emissions as defined in general provisions to 40 CFR part 63 or the facility potential to emit is more than 10 tons per year for a single HAP or more than 25 tons per year for multiple HAP. In addition, subpart DD cross-references control requirements to be applied to specific types of affected sources: Tanks-level 1, containers, surface impoundments, individual drain systems, oil-water separators and organic water separators, loading, transfer, and storage systems. This information is being collected to assure compliance with 40 CFR part 63, subpart DD. Organic HAP emissions are the pollutants regulated under this subpart.

Owners or operators of the affected facilities described must make one-time-only notifications. Owners or operators are also required to maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility, or any period during which the monitoring system is inoperative. Semiannual reports of excess emissions (or reports certifying that no exceedances have occurred) are required. These notifications, reports, and records are essential in determining compliance; and are required, in general, of all sources subject to NESHAP.

These standards rely on the control of organic HAP emissions by control technology. The required notifications are used to inform the Agency or delegated authority when a source becomes subject to the standard. The reviewing authority may then inspect the source to check if the pollution control devices are properly installed and operated, leaks are being detected and repaired and the standard is being met. Performance test reports are needed as these are the Agency's record of a source's initial capability to comply with the emission standard, and serve as a record of the operating conditions under which compliance was achieved.

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 are listed in 40 CFR part 9 and 48 CFR chapter 15, and are identified on the form and/or instrument, if applicable.

Burden Statement: The annual public reporting and recordkeeping burden for this collection of information is estimated to average 218 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; 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.

Respondents/Affected Entities: Off-site waste and recovery operations.

Estimated Number of Respondents: 236.

Frequency of Response: On occasion and semiannually.

Estimated Total Annual Hour Burden: 154,306 hours.

Estimated Total Cost: $9,928,000, which includes zero annualized capital/

startup costs, $5,000 annual O&M costs, and $9,923,000 annual labor costs.

Changes in the Estimates: There is a decrease of 7,744 hours in the total estimated burden currently identified in the OMB Inventory of Approved ICR Burdens. This is due to a decrease in the number of sources.

Dated: January 22, 2004.

Doreen Sterling,

Acting Director, Collection Strategies Division.

[FR Doc. 04–1976 Filed 1–29–04; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[ER–FRL–6647–8]

Environmental Impact Statements; Notice of Availability

Responsible Agency: Office of Federal Activities, General Information (202) 260–5073 or (202) 260–5075.

Weekly receipt of Environmental Impact Statements

Filed January 19, 2004, through January 23, 2004

Pursuant to 40 CFR 1506.9.

EIS No. 040025, DRAFT EIS, USN, MS, Purchase of Land in Hancock County, Mississippi, for a Naval Special Operations Forces Training Range, To Improve Riverine and Jungle Training Available, John C. Stennis Space Center, Hancock County, MS, Comment Period Ends: March 15, 2004, Contact: Richard Davis (843) 820–5587.

EIS No. 040026, FINAL EIS, AFS, WY, Medicine Bow National Forest Revised Draft Land and Resource Management Plan, Implementation, Albany, Carbon and Laramie Counties, WY, Wait Period Ends: March 1, 2004, Contact: Mary Peterson (307) 745–2300.

EIS No. 040027, DRAFT EIS, IBR, NB, CO, WY, Programmatic EIS—Platte River Recovery Implementation Program, Assessing Alternatives, Cooperative, Endangered Species Recovery Program, The Four Target Species are Whooping Crane, Interior Least Tern, Piping Plover and Pallid Sturgeon, NB, WY and CO, Comment Period Ends: April 2, 2004, Contact: Curt Brown (303) 445–2096.

This document is available on the Internet at: *http://www.platteriver.org.*

EIS No. 040028, DRAFT EIS, FHW, PA, U.S. 202, Section ES1 Improvements Project, To Relieve Traffic Congestion and Improve the Corridor, Funding and U.S. Army COE Section 404 Permit, Delaware and Chester Counties, PA, Comment Period Ends: April 9, 2004, Contact: James A. Cheatham (717) 221–3461.

EIS No. 040029, FINAL SUPPLEMENT, AFS, CA, NV, Sierra Nevada Forest Plan Amendment Project, Implementation, several counties, CA and NV, Wait Period Ends: March 1, 2004, Contact: Kathleen Morse (707) 562–8822.

EIS No. 040030, FINAL EIS, AFS, AL, Alabama National Forests Revised Land and Resource Management Plan, Implementation, Bankhead National Forest, Lawrence, Winston and Franklin Counties, AL, Wait Period Ends: March 1, 2004, Contact: Felicia Humphrey (334) 832–4470.

This document is available on the Internet at: *http://www.southenregion.fs.fed.us/planning/sap/sap-docs/shtm.*

EIS No. 040031, FINAL EIS, AFS, VA, KY, WV, Jefferson National Forest Revised Land and Resource Management Plan, Implementation, Mount Rogers National Recreation Area, Clinch, Glenwood, New Castle, and New River Valley Rangers Districts, VA, WV and KY, Wait Period: March 1, 2004, Contact: Nancy Ross (540) 265–5172.

EIS No. 040032, DRAFT EIS, AFS, CO, WY, Southern Rockies Canada Lynx Amendment, Incorporating Management Direction for Canada Lynx Habitat by Amending Land and Resource Management Plans for Arapaho-Roosevett, Pike-San Isabel, Grand Mesa-Uncompahgre-Gunnison, San Juan, Rio Grande and Medicine Bow-Routt National Forests, Implementation, C0 and WY, Comment Period Ends: April 29, 2004, Contact: Lois Poppert (559) 359–7023.

This document is available on the Internet at: *http://www.fs.fed.us/r2/lynx.*

EIS No. 040033, DRAFT EIS, UAF, WV, Aircraft Conversion for the 167th Air Wing (167 AW) of the West Virginia Air National Guard, Converting C–13OH Transport Aircraft to the Larges C–5 Transport Aircraft, Acquisition of Land via Lease, and Construction of Facilities on existing and acquired Parcel, Berkely County, WV, Comment Period Ends: March 15, 2004, Contact: Lt. Col. Tammy Mitwik (301) 836–8636.

EIS No. 040034, FINAL EIS, IBR, CA, Programmatic EIS—Environmental Water Account Project, Water Management Strategy to Protect the At-Risk Native Delta-Dependent Fish Species and Water Supply Improvements, U.S. Fish and Wildlife Service Endangered Species Act Section 7 and U.S. Army Corps Section 10 Permits Issuance, CA, Wait Period Ends: March 1, 2004, Contact: Sammie Cervantes (916) 978–5104.

EIS No. 040035, FINAL EIS, FHW, PA, Mon/Fayette Transportation Project, Improvements from PA–51 to I–376 in Monroeville and Pittsburgh, Funding, US Coast Guard Bridge Permit and U.S. Army COE Section 404 Permit Issuance, Allegheny County, PA, Wait Period Ends: April 06, 2004, Contact: Karyn E. Vandervoort (717) 221–2276.

EIS No. 040036, FINAL EIS, FRC, FL, Tractebel Calypso Pipeline Project, Natural Gas Transportation Service for 832,000 dekatherms/day to South Florida, Construction and Operation, Right-of-Way Grant and U.S. Army COE Section 10 and 404 Permits Issuance, Exclusive Economic Zone (EEZ) with the Bahamas, Fort Lauderdale, Broward County, FL, Wait Period Ends: March 1, 2004, Contact: Thomas Russo (202) 502–8371.

This document is available on the Internet at: *http://www.ferc.gov.*

EIS No. 040037, FINAL EIS, AFS, CO, North Fork of the South Platte and the South Platte Rivers, Wild and Scenic River Study, To Determine their Suitability for Inclusion into the National Wild and Scenic Rivers System, Pike and San Isabel National Forests, Comache and Cimarron National Grasslands, Douglas, Jefferson, Park and Teller Counties, CO, Wait Period Ends: April 2, 2004, Contact: John Hill (719) 553–1414.

EIS No. 040038, FINAL EIS, AFS, TN, Cherokee National Forest Revised Land and Resource Management Plan, Implementation, Carter, Cocke, Greene, Johnson, McMinn, Monroe, Polk, Sullivan and Unicoi, TN, Wait Period Ends: March 1, 2004, Contact: Robert T. Jacobs (404) 347–4177.

EIS No. 040039, FINAL EIS, AFS, SC, Sumter National Forest Revised Land and Resource Management Plan, Implementation, Oconee, Chester, Fairfield, Laurens, Newberry, Union-Abbeville, Edgefield, Greenwood, McCormick and Saluda Counties, SC, Wait Period Ends: March 1, 2004, Contact: Jerome Thomas (803) 561–4000.

This document is available on the Internet at: *http://www.fs.fed.us/r8/fms.*

EIS No. 040040, DRAFT SUPPLEMENT, NOA, FL, MS, TX, AL, LA, Reef Fish Management Plan Amendment 22, To Set Red Snapper Sustainable Fisheries Act Targets and Thresholds, Set a Rebuilding Plan, and Establish Bycatch Reporting Methodologies for the Reef Fish Fishery, Gulf of Mexico, Comment Period Ends: March 15, 2004, Contact: Dr. Roy E. Crabtree (301) 713–1622.

EIS No. 040041, DRAFT EIS, HUD, NY, Generic EIS—World Trade Center Memorial and Redevelopment Plan, To Remember, Rebuild and Renew what was lost on September 11, 2001, Construction in the Borough of Manhattan, New Year County, NY, Comment Period Ends: March 15, 2004, Contact: William H. Kelley (212) 962–2300.

This document is available on the Internet at: *http://www.renewnyc.com/plan_des_dev/frm_ comments.asp.*

EIS No. 040042, FINAL EIS, NRC, NY, Generic—License Renewal for R.E. Ginna Nuclear Power Plant, Supplement 14, NUREG–1437, Implementation, Wayne County, NY, Wait Period Ends: March 1, 2004, Contact: Robert Schaaf (301) 415–1312.

This document is available on the Internet at: *http://www.nrc.gov/reading-rm.html.*

EIS No. 040043, FINAL EIS, AFS, GA, Chattahoochee-Oconee National Forests Revised Land and Resource Management Plan, Implementation, several Counties, GA, Wait Period Ends: March 1, 2004, Contact: Robert T. Jacob (404) 347–4177.

This document is available on the Internet at: *http://www.fs.fed.us/conf.*

Amended Notices

EIS No. 030501, DRAFT EIS, IBR, CA, Lake Berryessa Visitor Services Plan, Future Use and Operation, Solano Project Lake Berryessa, Napa County, CA, Comment Period Ends: March 22, 2004, Contact: Stephen Rodgers (707) 966–2111.

Revision of **Federal Register** Notice Published on 11/7/2003: CEQ Comment Period Ending 2/4/2004 has been Extended to 3/22/2004.

EIS No. 040001, DRAFT EIS, BLM, CA, King Range National Conservation Area (KRNCA) Resource Management Plan, Implementation, Humboldt and Mendocino Counties, CA, Comment Period Ends: April 16, 2004, Contact: Lynda J. Roush (707) 825–2300.

Revision of **Federal Register** Notice Published FR 1–16–04, Correction to Web site Address: *http://www.ca.blm.gov/arcata/.*

EIS No. 040002, DRAFT EIS, BLM, AK, Alpine Satellite Development Plan, Proposal to Construct and Operate Five Oil Production Pads, Associated Well, Roads, Airstrips, Pipelines and Powerlines, Northeast Corner of the National Petroleum Reserve-Alaska, Colville River Delta, North Slope Borough, AK, Comment Period Ends: March 1, 2004, Contact: James H. Ducker (907) 271–3130.

Revision of **Federal Register** Notice Published FR–01–16–04, Correction Web site Address: *http://www.alpine-satellites-eis.com.*

EIS No. 040021, DRAFT SUPPLEMENT, NOA, HI, GU, AS, Pelagic Fisheries of the Western Pacific Region, Fishery Management Plan, Regulatory Amendment, Management Measures to Implement New Technologies for the Western Pacific Pelagic Longline Fisheries, Hawaii, American Samoa, Guam and Commonwealth of the Northern Mariana Island, Comment Period Ends: February 23, 2004, Contact: Alvin Katekaru (808) 973–2937.

Revision of **Federal Register** Notice Published on 1/23/2004: Correction to Web site Address, it should be: *http//swr.nmfs.noaa.gov/pir/,* and Correction to Wavier Granted Under § 1506.10(d) to Alternative Procedures Granted by CEQ Under § 1502.9(c)(4).

Dated: January 27, 2004.

Ken Mittelholtz,

Environmental Protection Specialist, Office of Federal Activities.

[FR Doc. 04–2008 Filed 1–29–04; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[ER–FRL–6647–9]

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 the **Federal Register** dated April 4, 2003 (68 FR 16511).

Draft EISs

ERP No. DNRS–L31004–ID Rating LO, Little Wood River Irrigation District, Gravity Pressurized Delivery System Construction, Funding and U.S. Army COE Section 404 Permit, Townships of 1 North, 1 South and 2 South of Range 21 East of the Boise Merridan, City of Carey, Blaine County, ID.

Summary: EPA recommended that wetland mitigation plans include descriptions of potential off-site mitigation areas, assurances that appropriate hydrology exists and that monies slated for mitigation be bonded until it is demonstrated that wetlands values and function have been adequately replaced. EPA requested that the final EIS include additional information on Environmental Justice analyses and Tribal consultations.

Final EISs

ERP No. F–FHW–F40398–IN Indianapolis Northeast Corridor Transportation Connections Study to Identify Actions to Reduce Expected Year 2025 Traffic Congestion and Enhance Mobility, Between I–69: from I–465 to IN–328; I–465: from U.S. 31 to I–70; I–70: from I–65 to I–465: IN–37 from I–69 to Allisonville Road (Noblesville), Marion and Hamilton Counties, IN.

Summary: EPA has no objections to the preferred alternative. EPA does request that the Record of Decision provide clarification on monitoring spawning fish and wetland mitigation.

ERP No. F–FHW–G40175–TX TX–45 Highway Southeast Study, I–35 south at Farm-to-Market Road-1327 to TX–130/US 183, Local Regional Enhancements to the National Transportation Systems, Funding and Right-of-Way Permit Issuance, Travis County, TX.

Summary: EPA has no objections to the selection of the preferred alternative.

ERP No. FS–NRC–E06014–SC Generic EIS—License Renewal of Nuclear Plants, Supplement 13 regarding H.B. Robinsion Steam Electric Plant, Unit No. 2, Operating License Renewal for 20–Years, Site Specific, on the Shore of Lake Robinsion, Darlington and Chesterfield Counties, SC.

Summary: EPA expressed environmental concerns, and agreed with the NRC's proposal to require radiological monitoring of all plant effluents, and appropriate storage and disposition of radiological waste.

Dated: January 27, 2004.

Ken Mittelholtz,

Environmental Specialist, Office of Federal Activities.

[FR Doc. 04–2009 Filed 1–29–04; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–7615–5]

Teleconference Meeting of the National Drinking Water Advisory Council: Conference Call To Continue Discussion of the Formation of a Water Security Working Group

AGENCY: Environmental Protection Agency.

ACTION: Notice.

SUMMARY: The U.S. Environmental Protection Agency (EPA) is announcing a teleconference meeting to continue discussion on the formation of a Water Security Working Group of the National Drinking Water Advisory Council (NDWAC). The EPA is designated as the lead agency for the security of the nation's drinking water and wastewater sectors. To assist these sectors in becoming more secure against terrorist threats, the Agency is proposing to develop best security practices for drinking water and wastewater facilities. The National Drinking Water Advisory Council (NDWAC) was established to provide practical and independent advice, consultation and recommendations to the Agency on the activities, functions and policies related to the implementation of the Safe Drinking Water Act. During the November 19–20, 2003, meeting, the NDWAC decided to forgo an official vote on the formation of the Water Security Working Group (WSWG) until there was an official charge before the members. It was decided that once members of NDWAC had the opportunity to review the charge for the proposed working group, a conference call would be held to continue discussion on the formation of the Water Security Working Group.

Subsequently, a draft charge for the Water Security Working Group was drawn up for NDWAC's consideration, as follows: To provide recommendations to the full NDWAC to: (1) Identify and prioritize a suite of best security practices for water utilities to improve security; (2) propose incentives to help facilitate a broad and receptive response amongst the water sector to implement these best practices; and (3) recommend mechanisms to recognize and measure the implementation of these best security practices. Upon completion of the charge, the WSWG will make recommendations to the full NDWAC.

EPA is hereby giving notice that a NDWAC teleconference meeting has been scheduled to review and discuss the draft charge, and to decide on the formation of the Water Security Working Group.

DATES: The conference call is scheduled to take place at 11 a.m., Eastern Time, on February 10, 2004.

ADDRESSES: Council members teleconference into Room 2123 of the EPA East Building, which is physically located at 1201 Constitution Avenue, NW., Washington, DC.

FOR FURTHER INFORMATION CONTACT: Interested participants from the public should contact Marc Santora, Designated Federal Officer, U.S. Environmental Protection Agency, Office of Ground Water and Drinking Water, Water Security Division (Mail Code 4601–M), 1200 Pennsylvania Avenue, NW., Washington, DC, 20460. Please contact Marc Santora at *santora.marc@epa.gov* or call (202) 564–1597 to register and receive pertinent details such as the the telephone number and extension to participate in the conference call.

SUPPLEMENTARY INFORMATION: The Council encourages the public's participation. A limited number of additional phone lines may be available for members of the public that are outside of the Washington, DC, metropolitan commuting area and are unable to attend in person. Any additional teleconferencing lines that are available will be reserved on a first-come, first-serve basis by the Designated Federal Officer. To ensure adequate time for public involvement, oral statements will be limited to five minutes, and it is preferred that only one person present the statement on behalf of a group or organization. Any person who wishes to file a written statement can do so before or after a Council meeting. Written statements received prior to the meeting will be distributed to all members of the Council before any final discussion or vote is completed. Any statements received after the meeting will become part of the permanent meeting file and will be forwarded to the Council members for their information. Any person needing special accommodations at this meeting, including wheelchair access, should contact the Designated Federal Officer, at the number or e-mail listed under the **FOR FURTHER INFORMATION CONTACT** section, at least five business days before the meeting so that appropriate arrangements can be made.

Dated: January 23, 2004.

Cynthia C. Dougherty,

Director, Office of Ground Water and Drinking Water.

[FR Doc. 04–1968 Filed 1–29–04; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–7615–6]

Draft Toxicological Review of Dichlorobenzenes and Integrated Risk Information System (IRIS) Summary for 1,2-DCB, 1,3-DCB and 1,4-DCB

AGENCY: Environmental Protection Agency.

ACTION: Notice of external peer-review panel meeting.

SUMMARY: The U.S. Environmental Protection Agency (EPA) is announcing an external peer-review panel meeting to review the external review draft documents entitled, "Toxicological Review of Dichlorobenzenes and IRIS Summary for 1,2-DCB, 1,3-DCB and 1,4-DCB" (NCEA–S–1618). The document was prepared by EPA's National Center for Environmental Assessment (NCEA) of the Office of Research and Development. EPA will use comments and recommendations from the expert panel meeting to finalize the draft document.

DATES: The peer-review panel workshop will begin on Thursday, February 12, 2004, at 8 a.m. and ends at 5 p.m Eastern Standard Time. The 30-day public comment period begins January 30, 2004, and ends March 1, 2004. Technical comments must be postmarked by March 1, 2004.

ADDRESSES: The external peer-review panel meeting will be held at the Andrew W. Briedenbach Environmental Research Center, U.S. EPA, 26 W. Martin Luther King Dr., Cincinnati, OH 45268. Under an Interagency Agreement with EPA and the Department of Energy, the Oak Ridge Institute for Science and Education (ORISE) is organizing, convening, and conducting the peer-review panel meeting. To attend the meeting, register by February 5 by calling Ms. Rachel Smith, ORISE, PO Box 117, MS 17, Oak Ridge, TN 37831–0117; at 865–241–6428 or by facsimile at 865–241–3168. She may also be reached via e-mail at *smithr@orau.gov*. Interested parties may also register on-line at: *http://www.orau.gov/dichlorobenzenereview*. Space is limited, and reservations will be accepted on a first-come, first-served basis.

The document is available primarily on the NCEA web site at www.epa.gov/ncea under the What's New and Publications menus. A limited number of paper copies are available by contacting the IRIS Hotline at 202–566–1676; facsimile: 202–566–1749. If you are requesting a paper copy, please provide your name, mailing address, and the document title and number, "Draft Toxicological Review of Dichlorobenzenes and IRIS Summary for 1,2-DCB, 1,3-DCB, and 1,4-DCB" (NCEA–S–1618). Copies are not available from ORISE. Comments may be submitted electronically, by mail, by facsimile, or by hand delivery/courier. Please follow the detailed instructions as provided in the **SUPPLEMENTARY INFORMATION** section.

FOR FURTHER INFORMATION CONTACT: Questions regarding registration and logistics should be directed to Ms. Rachel Smith, ORISE, PO Box 117, MS 17, Oak Ridge, TN 37831–0117; telephone: 865–241–6428; facsimile at 865–241–3168. She may also be reached via e-mail at *smithr@orau.gov*.

If you have questions about the document, contact Chandrika Moudgal, National Center for Environmental Assessment, U.S. EPA, 26 W. Martin Luther King Dr., Cincinnati, OH 45268; phone: 513–569–7078; facsimile: 513–569–7475; email: *moudgal.chandrika@epa.gov*.

SUPPLEMENTARY INFORMATION:

I. Information on the Document

The draft report is a reassessment of the chronic health effects of dichlorobenzenes which were first entered into the IRIS data base in 1989 (1,2-DCB), 1990 (1,3-DCB), and 1994 (1,4-DCB). The report provides the scientific basis for deriving or not deriving an oral reference dose (RfD) and inhalation reference concentration (RfC) for the noncancer health risk from exposure to each of the three DCB isomers. A cancer assessment for each is also included in the draft report.

IRIS is a data base that contains scientific Agency consensus positions on potential adverse human health effects that may result from chronic (or lifetime) exposure to specific chemical substances found in the environment. The data base (available on the internet at *http://www.epa.gov/iris)* contains qualitative and quantitative health effects information for more than 500 chemical substances that may be used to support the first two steps (hazard identification and dose-response evaluation) of the risk assessment process. When supported by available data, the data base provides RfDs and RfCs for chronic health effects, and oral slope factors and inhalation unit risks for carcinogenic effects. Combined with specific exposure information, government and private entities use IRIS to help characterize public health risks of chemical substances in a site-specific situation and thereby support risk management decisions designed to protect public health.

Dichlorobenzenes (CAS Nos. 95–50–1, 541–73–1, and 106–46–7) are produced in an isomeric mixture from the reaction of liquid benzene with chlorine gas in the presence of a catalyst at moderate temperature and atmospheric pressure. Individual isomers of Dichlorobenzene are used primarily as reactants in chemical synthesis, as process solvents, and as formulation solvents. 1,2-Dichlorobenzene is used in the production of 3,4-dichloroaniline, a base material for herbicides; as a solvent for waxes, gums, resins, tars, rubbers, oils, and asphalts; as an insecticide for termites and locust borers; as a degreasing agent for metals, leather, paper, dry-cleaning, bricks, upholstery, and wool; as an ingredient in metal polishes; in motor oil additive formulations; and in paints. 1,3-Dichlorobenzene is used in the production of herbicides, insecticides, pharmaceuticals, and dyes. 1,4-Dichlorobenzene is used as an air freshener, as a moth repellent in moth balls or crystals, and in other pesticide applications. 1,4-Dichlorobenzene is also used in the manufacture of 2,5-dichloroaniline and pharmaceuticals, polyphenylene sulfide resins, and in the control of mildew.

II. How To Submit Technical Comments

EPA has established an official public docket for this action under Docket ID No. ORD–2004–0002. The official public docket consists of the document referenced in this notice and a list of charge questions that have been submitted to the external peer reviewers. Both documents are available on the Internet at *http://www.epa.gov/edocket/*. Once in the system, select "search," then key in the appropriate docket identification number.

Submit your comments, identified by docket ID number ORD–2004–0002, online at *http://www.epa.gov/edocket* (EPA's preferred method); by e-mail to *ord.docket@epa.gov*; by mail to EPA Docket Center, U.S. Environmental Protection Agency (mail code 2822T), 1200 Pennsylvania Ave., NW., Washington, DC 20460–0001; or by hand delivery or courier to EPA Docket Center, EPA West, Room B102, 1301 Constitution Ave., NW., Washington, DC, between 8:30 a.m. and 4:30 p.m. Monday through Friday, excluding legal holidays. Comments on a disk or CD–ROM should be formatted in Wordperfect or ASCII file, avoiding the use of special characters and any form of encryption.

EPA's policy is that public comments, whether submitted electronically or in paper, will be made available for public viewing in EPA's electronic public docket as EPA receives them and without change, unless the comment contains copyrighted material, confidential business information (CBI), or other information whose disclosure is restricted by statute.

Dated: January 23, 2004.

Peter W. Preuss,

Director, National Center for Environmental Assessment.

[FR Doc. 04–1973 Filed 1–29–04; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–7615–7]

Proposed Administrative Settlement Under the Comprehensive Environmental Response, Compensation, and Liability Act

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice; request for public comment.

SUMMARY: The U.S. Environmental Protection Agency is proposing to enter into a *de minimis* settlement pursuant to section 122(g)(4) of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended ("CERCLA"), 42 U.S.C. 9622(g)(4). This proposed settlement is intended to resolve the liability under CERCLA of Materia Medica, Inc., formerly known as Polysciences, Inc. ("Settling Party") for response costs incurred and to be incurred at the Malvern TCE Superfund Site, East Whiteland and Charlestown Townships, Chester County, Pennsylvania, relating to the Malvern TCE Superfund Site ("Site").

DATES: Comments must be provided on or before March 1, 2004.

ADDRESSES: Comments should be addressed to Suzanne Canning, Docket Clerk, U.S. Environmental Protection Agency, Region III, 1650 Arch Street, Philadelphia, PA 19103–2029, and should refer to the Malvern TCE Superfund Site, East Whiteland Township, Chester County, Pennsylvania.

FOR FURTHER INFORMATION CONTACT: Joan A. Johnson (3RC41), 215/814–2619, U.S.

Environmental Protection Agency, 1650 Arch Street, Philadelphia, Pennsylvania 19103–2029.

SUPPLEMENTARY INFORMATION: Notice of *de minimis* Settlement: In accordance with section 122(i)(1) of CERCLA, 42 U.S.C. 122(i)(1), notice is hereby given of a proposed administrative settlement concerning the Malvern TCE Superfund Site, in East Whiteland Chester County, Pennsylvania. The administrative settlement is subject to review by the public pursuant to this notice.

The Settling Party has agreed to pay $9,879.00 to the Hazardous Substances Trust Fund subject to the contingency that EPA may elect not to complete the settlement if comments received from the public during this comment period disclose facts or considerations which indicate the proposed settlement is inappropriate, improper, or inadequate. This amount to be paid by the Settling Party was based upon EPA's determination of Settling Party's fair share of liability of Settling Party relating to the Site. Monies collected from the Settling Party will be applied towards past and future response costs incurred by EPA or PRPs performing work at or in connection with the Site.

EPA is entering into this agreement under the authority of sections 107 and 122(g) of CERCLA, 42 U.S.C. 9607 and 9622(g). Section 122(g) authorizes settlements with *de minimis* parties to allow them to resolve their liabilities at Superfund Sites without incurring substantial transaction costs. Under this authority, EPA proposes to settle with Settling Party in connection with the Site, based upon a determination that Settling Party is responsible for 0.75 percent or less of the volume of hazardous substance sent to the Site. As part of this *de minimis* settlement, EPA will provide to the Settling Party a covenant not to sue or take administrative action against the Settling Party for reimbursement of response costs or injunctive relief pursuant to sections 106 and 107 of CERCLA, 42 U.S.C. 9606 and 9607, or for injunctive relief pursuant to section 7003 of the Resource Conservation and Recovery Act, 42 U.S.C. 6973, with regard to the Site.

The Environmental Protection Agency will receive written comments relating to this settlement for thirty (30) days from the date of publication of this Notice. A copy of the proposed Administrative Order on Consent can be obtained from Joan A. Johnson (3RC41), U.S. Environmental Protection Agency, Region III, 1650 Arch Street, Philadelphia, Pennsylvania, 19103–2029, or by contacting Joan A. Johnson at (215) 814–2619.

Dated: September 30, 2004.

Thomas Voltaggio,

Acting Regional Administrator, Region III.

[FR Doc. 04–1974 Filed 1–29–04; 8:45 am]

BILLING CODE 6560–50–P

FEDERAL COMMUNICATIONS COMMISSION

Public Information Collection(s) Requirement Submitted to OMB for Emergency Review and Approval

January 22, 2004.

SUMMARY: The Federal Communications Commission, as part of its continuing effort to reduce paperwork burden invites the general public and other Federal agencies to take this opportunity to comment on the following information collection(s), as required by the Paperwork Reduction Act of 1995, Public Law No. 104–13. An agency may not conduct or sponsor a collection of information unless it displays a currently valid control number. No person shall be subject to any penalty for failing to comply with a collection of information subject to the Paperwork Reduction Act (PRA) that does not display a valid control number. Comments are requested concerning (a) whether the proposed collection of information is necessary for the proper performance of the functions of the Commission, including whether the information shall have practical utility; (b) the accuracy of the Commission's burden estimate; (c) ways to enhance the quality, utility, and clarity of the information collected; and (d) ways to minimize the burden of the collection of information on respondents, including the use of automated collection techniques or other forms of information technology.

DATES: Written Paperwork Reduction Act (PRA) comments should be submitted on or before March 1, 2004. If you anticipate that you will be submitting comments, but find it difficult to do so within the period of time allowed by this notice, you should advise the contacts listed below as soon as possible.

ADDRESSES: Direct all PRA comments to Kristy L. LaLonde, Office of Management and Budget, Room 10234 NEOB, Washington, DC 20503, (202) 395–3087, or via fax at 202–395–5167 or via Internet at *Krista_L._LaLonde@omb.eop.gov.*, and Judith B. Herman, Federal Communications Commission, Room 1–C804, 445 12th Street, SW., Washington, DC 20554 or via internet to *Judith-B.Herman@fcc.gov.*

FOR FURTHER INFORMATION CONTACT: For additional information or copies of the information collections contact Judith B. Herman at 202–418–0214 or via Internet at *Judith-B.Herman@fcc.gov.*

SUPPLEMENTARY INFORMATION: *The Commission has requested emergency OMB processing review of this new information collection with an OMB approval by February 1, 2004.*

OMB Control Number: 3060–XXXX.

Title: Promoting Efficient Use of Spectrum through the Elimination of Barriers to the Development of Secondary Markets, WT Docket No. 00–230.

Form No.: FCC Form 603–T.

Type of Review: New collection.

Respondents: Business or other for-profit, not-for-profit institutions, and state, local and tribal government.

Number of Respondents: 1,770.

Estimated Time Per Response: 1–4 hours.

Frequency of Response: On occasion reporting requirement and recordkeeping requirement.

Total Annual Burden: 7,813 hours.

Total Annual Cost: $1,222,040.

Needs and Uses: The required notifications and applications will provide the Commission with useful information about spectrum usage and helps to ensure that the licensees and lessees are complying with Commission interference and non-interference policies and rules. Similar information and verification requirements have been used in the past for licensees operating under authorizations, and such requirements will serve to minimize interference, verify lessees are legally and technically qualified to hold licenses, and ensure compliance with Commission rules. The Commission has created an interim form, FCC Form 603–T, to be used until revisions to the FCC Form 603, and the Universal Licensing System (ULS) be programmed to recognized the changes to the FCC 603.

Federal Communications Commission.

Marlene H. Dortch,

Secretary.

[FR Doc. 04–2020 Filed 1–29–04; 8:45 am]

BILLING CODE 6712–01–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 February 17, 2004.

A. Federal Reserve Bank of St. Louis (Randall C. Sumner, Vice President) 411 Locust Street, St. Louis, Missouri 63166-2034:

1. Amy Golden McCay, Little Rock, Arkansas; to retain voting shares of ACME Holding Company, Inc., and thereby indirectly retain voting shares of Allied Bank, both of Mulberry, Arkansas.

B. Federal Reserve Bank of Kansas City (James Hunter, Assistant Vice President) 925 Grand Avenue, Kansas City, Missouri 64198-0001:

1. James E. Thielke, Cleo Springs, Oklahoma, as trustee of the Jarrett K. Parker Revocable Trust; to acquire voting shares of Cleo Bancshares, Inc., Cleo Springs, Oklahoma, and thereby indirectly acquire voting shares of Cleo State Bank, both of Cleo Springs, Oklahoma.

2. James E. Thielke, Cleo Springs, Oklahoma, as trustee of the Jarrett K. Parker Revocable Trust; to acquire voting shares of Hazelton Bancshares, Inc., and thereby indirectly acquire voting shares of Farmers State Bank, both of Hazelton, Kansas.

3. James E. Thielke, Cleo Springs, Oklahoma, as trustee of the Jarrett K. Parker Revocable Trust; to acquire voting shares of Meno Banchsares, Inc., and thereby indirectly acquire voting shares of Meno Guaranty Bank, both of Meno, Oklahoma.

Board of Governors of the Federal Reserve System, January 27, 2004

Jennifer J. Johnson,

Secretary of the Board.

[FR Doc. 04–2013 Filed 1–29–04; 8:45 am]

BILLING CODE 6210–01–S

FEDERAL RESERVE SYSTEM

Notice of Proposals to Engage in Permissible Nonbanking Activities or To Acquire Companies That Are Engaged in Permissible Nonbanking Activities

The companies listed in this notice have given notice under section 4 of the Bank Holding Company Act (12 U.S.C. 1843) (BHC Act) and Regulation Y (12 CFR Part 225) to engage *de novo*, or to acquire or control voting securities or assets of a company, including the companies listed below, that engages either directly or through a subsidiary or other company, in a nonbanking activity that is listed in § 225.28 of Regulation Y (12 CFR 225.28) or that the Board has determined by Order to be closely related to banking and permissible for bank holding companies. Unless otherwise noted, these activities will be conducted throughout the United States.

Each notice is available for inspection at the Federal Reserve Bank indicated. The notice also will be available for inspection at the offices of the Board of Governors. Interested persons may express their views in writing on the question whether the proposal complies with the standards of section 4 of the BHC Act. Additional information on all bank holding companies may be obtained from the National Information Center website at *www.ffiec.gov/nic/*.

Unless otherwise noted, comments regarding the applications must be received at the Reserve Bank indicated or the offices of the Board of Governors not later than February 17, 2004.

A. Federal Reserve Bank of Atlanta (Sue Costello, Vice President) 1000 Peachtree Street, N.E., Atlanta, Georgia 30303:

1. CNB Holdings, Inc., Alpharetta, Georgia; to engage in data processing activities through its subsidiary, Capital Financial Software, LLC, Norcross, Georgia, pursuant to section 225.28(b)(14)(i) of Regulation Y.

Board of Governors of the Federal Reserve System, January 27, 2004.

Jennifer J. Johnson,

Secretary of the Board.

[FR Doc. 04–2014 Filed 1–29–04; 8:45 am]

BILLING CODE 6210–01–S

GENERAL SERVICES ADMINISTRATION

Privacy Act of 1974; Proposed Revisions to a Privacy Act System of Records

AGENCY: General Services Administration.

ACTION: Notice of proposed revision to an existing Privacy Act system of records.

SUMMARY: The General Services Administration (GSA) proposes to revise the government-wide system of records, Travel Charge Card Program (GSA/GOVT–3). The purpose of the system is to maintain information that enables Federal government agencies to operate, manage, and control commercial travel and transportation by individuals on official government business and to provide cost data on travel, transportation, and related expenses worldwide. The system is being revised to include the date of birth of individuals whose records are in the system to facilitate identification of persons traveling for the Federal government. This notice also updates the authorities for maintaining the system and System Manager contact information; clarifies the scope of the system to show that it applies to all agencies; and includes editorial changes, also for clarification purposes.

DATES: Interested persons may submit written comments on this proposal. The revision will become effective without further notice on March 1, 2004 unless comments received on or before that date require changes to the proposal.

ADDRESSES: Comments should be submitted to the GSA Privacy Act Officer (CI), Office of the Chief People Officer, General Services Administration, 1800 F Street NW., Washington DC 20405.

FOR FURTHER INFORMATION CONTACT: Contact the GSA Privacy Act Officer at the above address, or call 202–501–1452.

Dated: January 26, 2004.

Fred Alt,

Chief Information Officer, Office of the Chief People Officer.

GSA/GOVT–3

SYSTEM NAME:

Travel Charge Card Program.

SYSTEM LOCATION:

This system of records is located in the finance office of the local installation of the Federal agency for which an individual has traveled. Records necessary for a contractor to perform under a contract are located at the contractor's facility.

CATEGORIES OF INDIVIDUALS COVERED BY THE SYSTEM:

Individuals covered by the system are current Federal employees who have their own government assigned charge card and all other Federal employees and authorized individuals who use a Federal account number for travel purposes.

CATEGORIES OF RECORDS IN THE SYSTEM:

Records include name, address, Social Security Number, date of birth, employment information, telephone numbers, information needed for identification verification, travel authorizations and vouchers, charge card applications, charge card receipts, terms and conditions for use of charge cards, and monthly reports from contractor(s) showing charges to individual account numbers, balances, and other types of account analyses.

AUTHORITY FOR MAINTENANCE OF THE SYSTEM:

5 U.S.C. 5707 and implementing Federal Travel Regulation, 41 CFR 300–304; 5 U.S.C. 5738; E.O. 11609; 36 CFR 13747 (1971); 31 U.S.C. 1348; Public Law. 107–56 § 326.

PURPOSE(S):

To assemble in one system information to provide government agencies with: (1) Necessary information on the commercial travel and transportation payment and expense control system which provides travelers charge cards and the agency an account number for official travel and related travel expenses on a worldwide basis; (2) attendant operational and control support; and (3) management information reports for expense control purposes.

ROUTINE USES OF RECORDS MAINTAINED IN THE SYSTEM, INCLUDING CATEGORIES OF USERS AND THE PURPOSES OF SUCH USES:

a. To disclose information to a Federal, State, local, or foreign agency responsible for investigating, prosecuting, enforcing, implementing, or carrying out a statute, rule, regulation, or order, where an agency becomes aware of a violation or potential violation of civil or criminal law or regulation.

b. To disclose information to a Member of Congress or a congressional staff member in response to an inquiry made at the request of the individual who is the subject of the record.

c. To disclose information to the contractor in providing necessary information for issuing credit cards.

d. To disclose information to a requesting Federal agency in connection with hiring or retaining an employee; issuing a security clearance; reporting an employee investigation; clarifying a job; letting a contract; or issuing a license, grant, or other benefit by the requesting agency where the information is relevant and necessary for a decision.

e. To disclose information to an appeal, grievance, or formal complaints examiner; equal employment opportunity investigator; arbitrator; exclusive representative; or other official engaged in investigating, or settling a grievance, complaint, or appeal filed by an employee.

f. To disclose information to officials of labor organizations recognized under Pub. L. 95–454, when necessary to their duties of exclusive representation on personnel policies, practices, and matters affecting working conditions.

g. To disclose information to a Federal agency for accumulating reporting data and monitoring the system.

h. To disclose information in the form of listings, reports, and records of all common carrier transactions including refunds and adjustments to an agency by the contractor to enable audits of carrier charges to the Federal government.

POLICIES AND PRACTICES FOR STORING, RETRIEVING, ACCESSING, RETAINING, AND DISPOSING OF RECORDS IN THE SYSTEM:

STORAGE:

Paper records are stored in file folders. Electronic records are stored within a computer and associated equipment.

RETRIEVABILITY:

Records are filed by name, Social Security Number, and/or credit card number.

SAFEGUARDS:

Paper records are stored in lockable file cabinets or secured rooms. Electronic records are protected by passwords, access codes, and entry logs. There is restricted access to credit card account numbers, and information is released only to authorized users and officials on a need-to-know basis.

RETENTION AND DISPOSAL:

Records are kept for 3 years and then destroyed, as required by the General Records Retention Schedules issued by the National Archives and Records Administration (NARA).

SYSTEM MANAGER AND ADDRESS:

Assistant Commissioner, Office of Acquisition (FC), Federal Supply Service, General Services Administration, Crystal Mall Building 4, 1941 Jefferson Davis Highway, Arlington, VA 22202.

NOTIFICATION PROCEDURE:

Inquiries by individuals should be addressed to the Finance Officer of the agency for which they traveled.

RECORD ACCESS PROCEDURES:

Requests from individuals should be addressed to the Finance Officer of the agency for which they traveled. Individuals must furnish their full name and the authorizing agency and its component to facilitate the location and identification of their records.

CONTESTING RECORD PROCEDURES:

Individuals wishing to request amendment of their records should contact the Finance Officer of the agency for which they traveled. Individuals must furnish their full name and the authorizing agency and component for which they traveled.

RECORD SOURCE CATEGORIES:

Charge card applications, monthly reports from the contractor, travel authorizations and vouchers, credit card companies, and data interchanged between agencies.

[FR Doc. 04–1946 Filed 1–29–04; 8:45 am]

BILLING CODE 6820–34–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Health Resources and Services Administration

Agency Information Collection Activities: Proposed Collection; Comment Request

In compliance with the requirement for opportunity for public comment on proposed data collection projects (section 3506(c)(2)(A) of Title 44, United States Code, as amended by the Paperwork Reduction Act of 1995, Public Law 104–13), the Health Resources and Services Administration (HRSA) publishes periodic summaries of proposed projects being developed for submission to OMB under the Paperwork Reduction Act of 1995. To request more information on the proposed project or to obtain a copy of the data collection plans and draft instruments, call the HRSA Reports Clearance Officer at (301) 443–1129.

Comments are invited on: (a) Whether the proposed collection of information is necessary for the proper performance of the functions of the Agency, including whether the information shall have practical utility; (b) the accuracy of the Agency's estimate of the burden of the proposed collection of information; (c) ways to enhance the quality, utility, and clarity of the information to be collected; and (d) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology.

Proposed Project: Section 510 Abstinence Education Grant Program—Guidance and Forms for the Title V Section 510 Abstinence Education Grant Program Application/Annual Report—NEW

The *Application Guidance for Section 510 of Title V of the Social Security Act* is used annually by all States and jurisdictions in applying for Abstinence Education Block Grants under Section 510 of Title V of the Social Security Act, and in preparing the required annual report. This guidance provides guidelines to the State Maternal and Child Health Agencies (MCH) agencies on how to apply for the appropriated Section 510 Abstinence Education funds.

The Section 510 Abstinence Education Grant program enables States to provide abstinence education, and at the option of States, where appropriate, mentoring, counseling, and adult supervision to promote abstinence from sexual activity, with a focus on those groups most likely to bear children out-of-wedlock. Projects must meet the legislative priorities as described in Section 510 of Title V of the Social Security Act. States agencies funded under the program are required to report annually on four national performance measures and a minimum of two State-developed performance measures.

The guidance used annually by the 47 States and 4 jurisdictions that have applied for and received Section 510 Abstinence Education Grant funding have an estimated average burden of 170 hours. The burden estimate for this activity is based upon information provided by the pilot States as well as previous experience by States in completing the application. The estimated response burden is as follows:

Application and Annual Report	Number of Respondents	Responses per Respondent	Burden Hours per Response	Total Burden Hours
States and Jurisdictions	51	1	170	8,670

Send comments to Susan G. Queen, Ph.D., HRSA Reports Clearance Officer, Room 14–45, Parklawn Building, 5600 Fishers Lane, Rockville, MD 20857. Written comments should be received within 60 days of notice.

Dated: January 23, 2004.

Tina M. Cheatham,

Acting Director, Division of Policy Review and Coordination.

[FR Doc. 04–1948 Filed 1–29–04; 8:45 am]

BILLING CODE 4165–15–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Office of the Secretary

[Document Identifier: OS–0990–TANF]

Agency Information Collection Activities: Proposed Collection; Comment Request

AGENCY: Office of the Secretary, HHS.

In compliance with the requirement of section 3506(c)(2)(A) of the Paperwork Reduction Act of 1995, the Office of the Secretary (OS), Department of Health and Human Services, is publishing the following summary of 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: Survey of State and Local Contracting Officials on Contracting for Social Services Under Charitable Choice;

Form/OMB No.: OS–0990–TANF;

Use: This data collection will enable HHS to document the extent to which state and local contracting officials in the Temporary Assistance for Needy Families and Substance Abuse Prevention and Treatment programs understand and implement Federal Charitable Choice regulations governing the provisions of social services by faith-based organizations. The information will be collected via a mail survey of a total of 173 respondents at the state and local levels.

Frequency: One time;

Affected Public: State, local, or Tribal governments;

Annual Number of Respondents: 173;

Total Annual Responses: 173;

Average Burden Per Response: 30 to 90 minutes;

Total Annual Hours: 175;

#2 Type of Information Collection Request: New collection;

Title of Information Collection: Implementation of an Internet & Paper-based Uniform Data Set for OMH-funded Activities;

Form/OMB No.: OS–0990–OMH;

Use: Involves transitioning the developed paper-based UDS modules to the Web-based prototype; implementing among OMH-partners. Will be regular system for reporting program management and performance data for all OMH-funded activities.

Frequency: Quarterly;

Affected Public: Not-for-profit institutions and State, Local, or Tribal Government;

Annual Number of Respondents: 2,772;

Total Annual Responses: 2,772;

Average Burden Per Response: 15 minutes to 15 hours;

Total Annual Hours: 2,772;

To obtain copies of the supporting statement and any related forms for the proposed paperwork collections referenced above, access the HHS Web site address at *http://www.hhs.gov/oirm/infocollect/pending/* or e-mail your request, including your address, phone number, OMB number, and OS document identifier, to *Naomi.Cook@hhs.gov.* or call the Reports Clearance Office on (202) 690–6162. Written comments and recommendations for the proposed information collections must be mailed within 30 days of this notice directly to the OMB Desk Officer at the address below: OMB Desk Officer: Brenda Aguilar, OMB Human Resources and Housing Branch, Attention: (OMB #0990–TANF/OMH), New Executive Office Building, Room 10235, Washington, DC 20503.

Dated: January 8, 2004.

Robert Polson,

Office of the Secretary, Paperwork Reduction Act Reports Clearance Officer.

[FR Doc. 04–1985 Filed 1–29–04; 8:45 am]

BILLING CODE 4168–17–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Medicare and Medicaid Services

[Document Identifier: CMS–1561; CMS–367, 367a, and 367c; CMS–417; CMS–10105 and CMS–10106]

Agency Information Collection Activities: Proposed Collection; Comment Request

AGENCY: Centers for Medicare and Medicaid Services.

In compliance with the requirement of section 3506(c)(2)(A) of the Paperwork Reduction Act of 1995, the Centers for Medicare and Medicaid Services (CMS) (formerly known as the Health Care Financing Administration (HCFA)), 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 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:* Extension of a currently approved collection; *Title of Information Collection:* Health Insurance Benefit Agreement and Supporting Regulations in 42 CFR Section 489; *Form No.:* CMS–1561 (OMB# 0938–0832); *Use:* Applicants to the Medicare program are required to agree to provide services in accordance with Federal requirements. The CMS–1561 is essential for CMS to ensure that applicants are in compliance with the requirements. Applicants will be required to sign the completed form and provide operational information to CMS to assure that they continue to meet the requirements after approval; *Frequency:* Other: as needed; *Affected Public:* Business or other for-profit, Not-for-profit institutions, and State, Local or Tribal Government; *Number of Respondents:* 3,000; *Total Annual Responses:* 3,000; *Total Annual Hours:* 150.

2. *Type of Information Collection Request:* Extension of a currently approved collection; *Title of Information Collection:* Medicaid Drug Rebate Program—Manufacturers; *Form No.:* 0938–0578 (CMS–367, 367a, and 367c); *Use:* Section 1927 requires drug manufacturers to enter into and have in effect a rebate agreement with the Federal Government for States to receive funding for drugs dispensed to Medicaid recipients; *Frequency:* Quarterly; *Affected Public:* Business or other for-profit; *Number of Respondents:* 551; *Total Annual Responses:* 2,204; *Total Annual Hours:* 54,660.

3. *Type of Information Collection Request:* Extension of a currently approved collection; *Title of Information Collection:* Hospice Request for Certification in the Medicare Program; *Form No.:* CMS–417 (OMB# 0938–0313); *Use:* The Hospice Request for Certification Form is used for hospice identification, screening, and to initiate the certification process. The information captured on this form is entered into a data base which assists CMS in determining whether providers have sufficient personnel to participate in the Medicare program; *Frequency:* Annually; *Affected Public:* Business or other for-profit, Not-for-profit institutions, Federal Government, and State, local or tribal government; *Number of Respondents:* 2,286; *Total Annual Responses:* 2,286; *Total Annual Hours:* 430.

4. *Type of Information Collection Request:* New collection; *Title of Information Collection:* End Stage Renal Disease Hemodialysis Patient Experience of Care (CAHPS) Survey; *Form No.:* CMS–10105 (OMB# 0938–NEW; *Use:* The ESRD CAHPS Hemodialysis Patient Experience of Care Survey follows CMS CAHPS efforts in other provider areas (Managed Care, FFS, hospital), and is intended to provide CMS with a picture of the experience of this vulnerable population who receive life sustaining dialysis therapy approximately three times per week from dialysis facilities. A variety of patient satisfaction surveys are already conducted regularly by a many dialysis organizations (although the majority of instruments have not been tested) and this tool would provide the ESRD community with a tested, standardized survey instrument that facilities could use for quality improvement and comparative purposes. It will provide information for consumer choice, data that facilities can use for internal quality improvement and external benchmarking against other facilities, and finally, information that CMS can use for public reporting and monitoring purposes. CMS has not yet determined if it will mandate the collection of this information. Potential approaches for national implementation are under consideration.; *Frequency:* On occasion; *Affected Public:* Individuals or Households; *Number of Respondents:* 1,800; *Total Annual Responses:* 1,800; *Total Annual Hours:* 460.

5. *Type of Information Collection Request:* New collection; *Title of Information Collection:* Medicare Authorization to Disclose Health Information; *Form No.:* CMS–10106 (OMB# 0938–NEW; *Use:* Unless permitted or required by law, the Privacy Act and Health Insurance Portability and Accountability Act (HIPAA) Privacy Rule prohibit covered entities from disclosing an individual's protected health information to a third party without a valid privacy authorization. The authorization must include specified core elements and certain statements. Medicare beneficiaries will use the "Medicare Authorization to Disclose Health Information" to authorize Medicare to disclose their protected health information to a third party.; *Frequency:* Other: an event basis; *Affected Public:* Individuals or Households; *Number of Respondents:* 39,000,000; *Total Annual Responses:* 1,000,000; *Total Annual Hours:* 250,000.

To obtain copies of the supporting statement and any related forms for the proposed paperwork collections referenced above, access CMS's Web Site address at *http://cms.hhs.gov/regulations/pra/default.asp,* or E-mail your request, including your address, phone number, OMB number, and CMS document identifier, to *Paperwork@hcfa.gov,* or call the Reports Clearance Office on (410) 786–1326. Written comments and recommendations for the proposed information collections must be mailed within 60 days of this notice directly to the CMS Paperwork Clearance Officer designated at the following address: CMS, Office of Strategic Operations and Regulatory Affairs, Division of Regulations Development and Issuances, Attention: Melissa Musotto, Room C5–14–03, 7500 Security Boulevard, Baltimore, Maryland 21244–1850.

Dated: January 22, 2004.

Melissa Musotto,

Acting Paperwork Reduction Act Team Leader, Office of Strategic Operations and Strategic Affairs, Division of Regulations Development and Issuances.

[FR Doc. 04–1983 Filed 1–29–04; 8:45 am]

BILLING CODE 4120–03–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Medicare and Medicaid Services

[Document Identifier: CMS–10101, CMS–10093, CMS–304&304a, CMS–565, and CMS–R–246]

Agency Information Collection Activities: Submission for OMB Review; Comment Request

AGENCY: Centers for Medicare and Medicaid Services.

In compliance with the requirement of section 3506(c)(2)(A) of the Paperwork Reduction Act of 1995, the Centers for Medicare and Medicaid Services (CMS) (formerly known as the Health Care Financing Administration (HCFA), 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 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:* Survey of Medicare Preferred Provider Organization Demonstration *Form No.:* CMS–10101 (OMB# 0938–NEW); *Use:* This information collection will be used to collect information from Medicare Beneficiaries to understand beneficiary experiences with the new managed care option and to understand which Medicare beneficiaries are attracted to the PPO model and why. CMS also wants to know what both enrollees and non-enrollees in PPOs know and understand about this new option; *Frequency:* Other: One-time Only; *Affected Public:* Individuals or Households; *Number of Respondents:* 38,216; *Total Annual Responses:* 38,216; *Total Annual Hours:* 9,556.

2. *Type of Information Request:* Extension of a currently approved collection; *Type of Information Collection:* CMS/AoA Aging and Disability Resource Center Grant Program; *CMS Form Number:* CMS–10093 (OMB# 0938–0903); *Use:* Information sought by CMSO/DEHPG is needed to award competitive grants to States to develop Aging and Disability Resource Centers; *Frequency:* Semi-annually; *Affected Public:* State, local, or tribal government, Not-for-profit institutions, Business or other for-profit; *Number of Respondents:* 24; *Total Annual Responses:* 48; *Total Annual Burden Hours:* 960.

3. *Type of Information Collection Request:* Extension of a currently approved collection; *Title of Information Collection:* Medicaid Drug Rebate; *Form No.:* CMS–304 and CMS–304a (OMB 0938–0676); *Use:* Section 1927 of the Social Security Act requires State Medicaid agencies to report to drug manufacturers and CMS on the drug utilization for their State and the amount of rebate to be paid by the manufacturer; *Frequency:* Quarterly; *Affected Public:* State, local, or tribal government; *Number of Respondents:* 51; *Total Annual Responses:* 204; *Total Annual Hours:* 6,125.

4. *Type of Information Collection Request:* Extension of a currently approved collection; *Title of Information Collection:* Medicare Qualification Statement for Federal Employees and Supporting Regulations in 42 CFR 406.15; *Form No.:* CMS–565 (OMB# 0938–0501); *Use:* The CMS–565 is completed by individuals filing for hospital insurance ([HI] Part A) benefits based upon their federal employment. This information is needed to determine if SSA/CMS can use (deem) federal employment prior to 1983 to provide quarters of coverage so the individual can qualify for free hospital insurance; *Frequency:* Other: One-time-only; *Affected Public:* Individuals or Households, Federal Government, State, Local, or Tribal Government; *Number of Respondents:* 4,300; *Total Annual Responses:* 4,300; *Total Annual Hours:* 717.

5. *Type of Information Collection Request:* Extension of a currently approved collection; *Title of Information Collection:* Medicare Consumer Assessment of Health Plan Survey—Medicare + Choice (CAHPS–M+C); *Form No.:* CMS–R–246(OMB# 0938–0732); *Use:* Under the Balanced Budget Act of 1997, CMS is required to provide general and plan comparative information to beneficiaries that will help them make more informed health plan choices. A CAHPS fee-for-service survey is needed to provide information comparable to those data collected from the CAHPS managed care survey; *Frequency:* Annually; *Affected Public:* Individuals or Households; *Number of Respondents:* 168,000; *Total Annual Responses:* 168,000; *Total Annual Hours:* 55,450.

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://cms.hhs.gov/regulations/pra/default.asp,* or E-mail your request, including your address, phone number, OMB number, and CMS document identifier, to *Paperwork@hcfa.gov,* or call the Reports Clearance Office on (410) 786–1326. Written comments and recommendations for the proposed information collections must be mailed within 30 days of this notice directly to the OMB desk officer: OMB Human Resources and Housing Branch, Attention: Brenda Aguilar, New Executive Office Building, Room 10235, Washington, DC 20503.

Dated: January 22, 2004.

Melissa Musotto,

Acting Paperwork Reduction Act Team Leader, CMS Reports Clearance Officer, Office of Strategic Operations and Strategic Affairs, Division of Regulations Development and Issuances.

[FR Doc. 04–1984 Filed 1–29–04; 8:45 am]

BILLING CODE 4120–03–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, DHHS

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.

Analogs of Thalidomide as Potential Angiogenesis Inhibitors

William D. Figg, Erin Lepper (NCI)
U.S. Provisional Application No. 60/486,515 filed 11 Jul 2003 (DHHS Reference No. E–272–2003/0–US–01)
Licensing Contact: Matthew Kiser; 301/435–5236; *kiserm@mail.nih.gov.*

The present disclosure relates to anti-angiogenesis compositions and methods, and particularly thalidomide analogs that actively inhibit angiogenesis in humans and animals.

Angiogenesis is the formation of new blood vessels from pre-existing vessels. Angiogenesis is prominent in solid tumor formation and metastasis. A tumor requires formation of a network of blood vessels to sustain the nutrient and oxygen supply for continued growth. Some tumors in which angiogenesis is important include most solid tumors and benign tumors, such as acoustic neuroma, neurofibroma, trachoma, and pyogenic granulomas. Prevention of angiogenesis could halt the growth of these tumors and the resultant damage due to the presence of the tumor.

The subject application discloses active thalidomide analogs that exhibit enhanced potency in the inhibition of undesirable angiogenesis, and methods for using these compounds to treat angiogenesis and solid tumors. In particular, the presently disclosed method provides for inhibiting unwanted angiogenesis in a human or animal by administering to the human or animal with the undesired angiogenesis a composition comprising an effective amount of the active thalidomide analogs. According to a more specific aspect, the method involves inhibiting angiogenesis by exposing a mass having the undesirable angiogenesis to an angiogenesis inhibiting amount of one or more compounds, or pharmaceutically acceptable salts of such compounds.

Serine Protease Inhibitors

Peter P. Roller, Peng Li (NCI)
U.S. Provisional Application No. 60/507,583 filed 30 Sep 2003 (DHHS Reference No. E–272–2002/0–US–01)
Licensing Contact: Matthew Kiser; 301/435–5236; *kiserm@mail.nih.gov.*

This disclosure concerns novel serine protease inhibitors and methods for using the inhibitors to reduce tumor progression and/or metastasis. Embodiments of the inhibitors are highly effective, selective inhibitors of matriptase, which has been implicated in tissue remodeling associated with the growth of cancerous tumors and cancer metastasis.

Angiogenesis and tumor invasion require that the normal tissue surrounding the tumor be broken down in a process referred to as tissue remodeling. Tissue remodeling is accomplished by a host of enzymes that break down the proteins in the normal tissue barriers comprising the extracellular matrix. Among the enzymes associated with degradation of the extracellular matrix and tissue remodeling are a number of proteases. The expression of some of these proteases has been correlated with tumor progression.

The disclosed compounds can be used to inhibit matriptase, MTSP1, or both, *in vitro* and *in vivo* and thus can be used in the prevention or treatment of conditions characterized by abnormal or pathological serine protease activity. For example, the compounds are useful for prevention or treatment of conditions characterized by the pathological degradation of the extracellular matrix, such as conditions characterized by neovascularization or angiogenesis, including cancerous conditions, particularly metastatic cancerous conditions where matriptase is implicated. The disclosed compounds can be used to decrease the degradation of the cellular matrix and thereby reduce concomitant tumor progression and metastasis. Conditions characterized by abnormal or pathological serine protease activity that can be treated according to the disclosed method include those characterized by abnormal cell growth and/or differentiation, such as cancers and other neoplastic conditions. Typical examples of cancers that may be treated according to the disclosed inhibitors and method include colon, pancreatic, prostate, head and neck, gastric, renal, and brain cancers.

Methods for Inhibiting Chaperone Proteins

Monica Marcu, Leonard Neckers, Theodor Schulte (NCI)
U.S. Patent Application No. 09/936,449 filed 20 Dec 2001 (DHHS Reference No. E–084–1999/0–US–07), with priority to 12 Mar 1999
Licensing Contact: George Pipia; 301/435–5560; *pipiag@mail.nih.gov.*

This invention is directed to depletion of the Heat Shock Protein (HSP)–90 with novobiocin. Hsp90 is an essential and abundant chaperone in eukaryotes. It is considered today an exciting molecular target for cancer therapy. NIH inventors demonstrated previously that the gyrase-B inhibitor, novobiocin, and its related coumarin derivatives interact with Hsp90, causing *in vitro* and *in vivo* depletion of key regulatory Hsp90-dependent proteins. Using deletion/mutation analysis, the inventors have identified the novobiocin binding domain on Hsp90 and demonstrated that it overlaps a functional ATP binding site, which was previously unknown. These results identify a second site on Hsp90 where the binding of small molecule inhibitors can significantly impact this chaperone's function, and thus support the hypothesis that both N- and C-terminal domains of Hsp90 interact to modulate chaperone activity. The inventors have performed preliminary *in vivo* experiments, treating mice carrying tumor xenografts with novobiocin encapsulated in Alzet pumps (slow, constant release for one month). The treated mice exhibited significantly slower tumor growth. Results of these studies demonstrated a significantly slower growth of tumors.

Dated: January 23, 2004.

Steven M. Ferguson,

Director, Division of Technology Development and Transfer, Office of Technology Transfer, National Institutes of Health.

[FR Doc. 04–1994 Filed 1–29–04; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

Notice of Meeting; Chairpersons, Boards of Scientific Counselors for Institutes and Centers at the National Institutes of Health

Notice is hereby given of a meeting scheduled by the Deputy Director for Intramural Research at the National Institutes of Health (NIH) with the Chairpersons of the Boards of Scientific Counselors. The Boards of Scientific Counselors are an advisory group to the Scientific Directors of the Intramural Research Programs at the NIH. This meeting will take place on February 6, 2004 from 9 a.m. to 3 p.m., at the NIH, 9000 Rockville Pike, Bethesda, MD, Building 1, Wilson Hall. The meeting will include a discussion of policies and procedures that apply to the regular review of NIH intramural scientists and their work, with special emphasis on clinical research.

The meeting will be open to the public, 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 contact Ms. Colleen Crone at the Office of Intramural Research, NIH, Building 1, Room 103, Telephone (301) 496–1921 or

FAX (301) 402–4273 in advance of the meeting.

The meetings is being published less than 15 days prior to the meeting due to scheduling conflicts.

Dated: January 21, 2004.

Raynard Kington,

Deputy Director, NIH.

[FR Doc. 04–1995 Filed 1–29–04; 8:45 am]

BILLING CODE 4140–01–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Cancer 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 Cancer Institute Initial Review Group, Subcommittee F—Manpower & Training.

Date: March 1–2, 2004.

Time: 8:30 a.m. to 5 p.m.

Agenda: To review and evaluate grant applications.

Place: Holiday Inn Georgetown, 2101 Wisconsin Avenue, NW, Washington, DC 20007.

Contact Person: Lynn McAmende, PhD, Scientific Review Administrator, Resources and Training Review Branch, Division of Extramural Activities, National Cancer Institute, National Institutes of Health, 6116 Executive Boulevard Room 8105, Bethesda, MD 20892, 301–451–4759, *amendel@mail.nih.gov.*

(Catalogue of Federal Domestic Assistance Program Nos. 93.392, Cancer Construction; 93.393, Cancer Cause and Prevention Research; 93.394, Cancer Detection and Diagnosis Research; 93.395, Cancer Treatment Research; 93.396, Cancer Biology Research; 93.397, Cancer Centers Support; 93.398, Cancer Research Manpower; 93.399, Cancer Control, National Institutes of Health, HHS)

Dated: January 23, 2004.

LaVerne Y. Stringfield,

Director, Office of Federal Advisory Committee Policy.

[FR Doc. 04–2003 Filed 1–29–04; 8:45 am]

BILLING CODE 4140–01–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Cancer Institute; 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 the meeting of the National Cancer Advisory Board.

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.

A portion of the meeting will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4), and 552b(c)(6), 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 Cancer Advisory Board.

Open: February 18, 2004, 8:30 a.m. to 4:20 p.m.

Agenda: Program reports and presentations; business of the Board.

Place: National Cancer Institute, 9000 Rockville Pike, Building 31, C Wing, 6th Floor, Conference Room 10, Bethesda, MD 20892.

Contact Person: Dr. Paulette S. Gray, Executive Secretary, National Cancer Institute, National Institutes of Health, 6116 Executive Boulevard, 8th Floor, Room 8141, Bethesda, MD 20892–8327, (301) 496–4218.

Name of Committee: National Cancer Advisory Board.

Closed: February 18, 2004, 4:20 p.m. to recess.

Agenda: Review of grant applications.

Contact Person: Dr. Paulette S. Gray, Executive Secretary, National Cancer Institute, National Institutes of Health, 6116 Executive Boulevard, 8th Floor, Room 8141, Bethesda, MD 20892–8327, (301) 496–4218.

Name of Committee: National Cancer Advisory Board.

Open: February 19, 2004, 8:30 a.m. to adjournment.

Agenda: Program reports and presentations; Business of the Board.

Contact Person: Dr. Paulette S. Gray, Executive Secretary, National Cancer Institute, National Institutes of Health, 6116 Executive Boulevard, 8th Floor, Room 8141, Bethesda, MD 20892–8327, (301) 496–4218.

This meeting is being published less than 15 days prior to the meeting due to scheduling conflicts. Any interested person may file written comments with the committee by forwarding the statement to the Contact Person listed on this notice. The statement should include the name, address, telephone number and when applicable, the business or professional affiliation of the interested person.

Information is also available on the Institute's/Center's home page: *http://www.deainfo.nci.nih.gov/advisory/ncab.htm,* where an agenda and any additional information for the meeting will be posted when available.

(Catalogue of Federal Domestic Assistance Program Nos. 93.392, Cancer Construction; 93.393, Cancer Cause and Prevention Research; 93.394, Cancer Detection and Diagnosis Research; 93.395, Cancer Treatment Research; 93.396, Cancer Biology Research; 93.397, Cancer Centers Support; 93.398, Cancer Research Manpower; 93.399, Cancer Control, National Institutes of Health, HHS)

Dated: January 23, 2004.

LaVerne Y. Stringfield,

Director, Office of Federal Advisory Committee Policy.

[FR Doc. 04–2004 Filed 1–29–04; 8:45 am]

BILLING CODE 4140–01–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Cancer 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 Cancer Institute Special Emphasis Panel, Small Animal Imaging (SAIRP).

Date: March 9–10, 2004.

Time: 8 a.m. to 5 p.m.

Agenda: To review and evaluate grant applications.

Place: Gaithersburg Hilton, 620 Perry Parkway, Gaithersburg, MD 20877.

Contact Person: Sherwood Githens, PhD, Scientific Review Administrator, Special Review and Logistics Branch, National Cancer Institute, National Institutes of Health, 6116 Executive Boulevard, Room 8068, Bethesda, MD 20892, (301) 435–1822.

(Catalogue of Federal Domestic Assistance Program Nos. 93.392, Cancer Construction; 93.393, Cancer Cause and Prevention Research; 93.394, Cancer Detection and Diagnosis Research; 93.395, Cancer Treatment Research; 93.396, Cancer Biology Research; 93.397, Cancer Centers Support; 93.398, Cancer Research Manpower; 93.399, Cancer Control, National Institutes of Health, HHS)

Dated: January 23, 2004.

LaVerne Y. Stringfield,

Director, Office of Federal Advisory Committee Policy.

[FR Doc. 04–2005 Filed 1–29–04; 8:45 am]

BILLING CODE 4140–01–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Cancer 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 Cancer Institute Initial Review Group, Subcommittee 1—Career Development.

Date: March 1–2, 2004.

Time: 8 a.m. to 5 p.m.

Agenda: To review and evaluate grant applications.

Place: Holiday Inn Georgetown, 2101 Wisconsin Avenue, NW., Washington, DC 20007.

Contact Person: Robert Bird, PhD, Scientific Review Administrator, Resources and Training Review Branch, National Cancer Institute, National Institutes of Health, 6116 Executive Blvd., MSC 8328, Room 8113, Bethesda, MD 20892–8328, 301–496–7978, *birdr@mail.nih.gov.*

(Catalogue of Federal Domestic Assistance Program Nos. 93.392, Cancer Construction; 93.393, Cancer Cause and Prevention Research; 93.394, Cancer Detection and Diagnosis Research; 93.395, Cancer Treatment Research; 93.396, Cancer Biology Research; 93.397, Cancer Centers Support; 93.398, Cancer Research Manpower; 93.399, Cancer Control, National Institutes of Health, HHS)

Dated: January 23, 2004.

LaVerne Y. Stringfield,

Director, Office of Federal Advisory Committee Policy.

[FR Doc. 04–2006 Filed 1–29–04; 8:45 am]

BILLING CODE 4140–01–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Cancer 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 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 Cancer Institute Special Emphasis Panel, Novel Technologies for Noninvasive Detection, Diagnosis, and Treatment of Cancer.

Date: April 6–7, 2004.

Time: 8 a.m. to 5 p.m.

Agenda: To review and evaluate contract proposals.

Place: Gaithersburg Hilton, 620 Perry Parkway, Gaithersburg, MD 20877.

Contact Person: Sherwood Githens, Ph.D, Scientific Review Administrator, Special Review and Logistics Branch, National Cancer Institute, National Institutes of Health, 6116 Executive Boulevard, Room 8068, Bethesda, MD 20892, (301) 435–1822.

(Catalogue of Federal Domestic Assistance Program Nos. 93.392, Cancer Construction; 93.393, Cancer Cause and Prevention Research; 93.394, Cancer Detection and Diagnosis Research; 93.395, Cancer Treatment Research; 93.396, Cancer Biology Research; 93.397, Cancer Centers Support; 93.398, Cancer Research Manpower; 93.399, Cancer Control, National Institutes of Health, HHS)

Dated: January 23, 2004.

LaVerne Y. Stringfield,

Director, Office of Federal Advisory Committee Policy.

[FR Doc. 04–2007 Filed 1–29–04; 8:45 am]

BILLING CODE 4140–01–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute on Drug Abuse; 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: National Institute on Drug Abuse Special Emphasis Panel, Centers Review Committee.

Date: February 23–24, 2004.

Time: 8:30 a.m. to 5 p.m.

Agenda: To review and evaluate grant applications.

Place: Ritz-Carlton Hotel at Pentagon City, 1250 South Hayes Street, Arlington, VA 22202.

Contact Person: Rita Liu, PhD, Health Scientist Administrator, Office of Extramural Affairs, National Institute on Drug Abuse, NIH, DHHS, Room 212, MSC 8401, 6101 Executive Boulevard, Bethesda, MD 20892–8401, (301) 435–1388.

Name of Committee: National Institute on Drug Abuse Initial Review Group, Medication Development Research Subcommittee.

Date: March 1, 2004.

Time: 8 a.m. to 6 p.m.

Agenda: To review and evaluate grant applications.

Place: Westin Grand, 2350 M Street, NW., Washington, DC 20037.

Contact Person: Khursheed Asghar, PhD, Chief, Basic Sciences Review Branch, Office of Extramural Affairs, National Institute on Drug Abuse, NIH, DHHS, Room 220, MSC 8401, (301) 443–2755.

Name of Committee: National Institute on Drug Abuse Special Emphasis Panel, Medication Development Conflicts.

Date: March 1, 2004.

Time: 4 p.m. to 5 p.m.

Agenda: To review and evaluate grant applications.

Place: Westin Grand, 2350 M Street, NW., Washington, DC 20037.

Contact Person: Eliane Lazar-Wesley, PhD, Health Scientist Administrator, Office of Extramural Affairs, National Institute on Drug Abuse, NIH, DHHS, Room 220, MSC 8401, 6101 Executive Boulevard, Bethesda, MD 20892–8401, 301–451–4530.

Name of Committee: National Institute on Drug Abuse Initial Review Group, Health Services Research Subcommittee.

Date: March 2–3, 2004.

Time: 8:30 a.m. to 5 p.m.

Agenda: To review and evaluate grant applications.

Place: Hyatt Regency Bethesda, One Bethesda Metro Center, 7400 Wisconsin Avenue, Bethesda, MD 20814.

Contact Person: Mark R. Green, PhD, Chief, CEASRB, Office of Extramural Affairs, National Institute on Drug Abuse, NIH, DHHS, Room 220, MSC 8401, 6101 Executive Boulevard, Bethesda, MD 20892–8401, (301) 435–1431.

Name of Committee: National Institute on Drug Abuse Initial Review Group, Treatment Research Subcommittee.

Date: March 2–3, 2004.

Time: 9 a.m. to 5 p.m.

Agenda: To review and evaluate grant applications.

Place: Hyatt Regency Bethesda, One Bethesda Metro Center, 7400 Wisconsin Avenue, Bethesda, MD 20814.

Contact Person: Kesinee Nimit, MD, Health Scientist Administrator, Office of Extramural Affairs, National Institute on Drug Abuse, NIH, DHHS, Room 220, MSC 8401, 6101 Executive Boulevard, Bethesda, MD 20892–8401, (301) 435–1432.

Name of Committee: National Institute on Drug Abuse Special Emphasis Panel, Member Conflict.

Date: March 3, 2004.

Time: 9 a.m. to 5 p.m.

Agenda: To review and evaluate grant applications.

Place: Hyatt Regency Bethesda, One Bethesda Metro Center, 7400 Wisconsin Avenue, Bethesda, MD 20814.

Contact Person: Teresa Levitin, PhD, Director, Office of Extramural Affairs, National Institute on Drug Abuse, NIH, DHHS, Room 220, MSC 8401, 6101 Executive Boulevard, Bethesda, MD 20892–8401, (301) 443–2755.

Name of Committee: National Institute on Drug Abuse Initial Review Group, Training and Career Development Subcommittee.

Date: March 9–11, 2004.

Time: 9 a.m. to 6 p.m.

Agenda: To review and evaluate grant applications.

Place: Residence Inn Bethesda, 7335 Wisconsin Avenue, Bethesda, MD 20814.

Contact Person: Mark Swieter, PhD, Health Scientist Administrator, Office of Extramural Affairs, National Institute on Drug Abuse, National Institutes of Health, DHHS, 6101 Executive Boulevard, Suite 234, Bethesda, MD 20892–8401, (301) 435–1389.

Name of Committee: National Institute on Drug Abuse Special Emphasis Panel, RFA DA04-004, NIDA Neuroproteomics Research Centers (NIDA NPRCs).

Date: March 14–16, 2004.

Time: 7 p.m. to 4 p.m.

Agenda: To review and evaluate grant applications.

Place: Ritz-Carlton Hotel at Pentagon City, 1250 South Hayes Street, Arlington, VA 22202.

Contact Person: Rita Liu, PhD, Health Scientist Administrator, Office of Extramural Affairs, National Institute on Drug Abuse, NIH, DHHS, Room 212, MSC 8401, 6101 Executive Boulevard, Bethesda, MD 20892–8401, (301) 435–1388.

Name of Committee: National Institute on Drug Abuse Special Emphasis Panel, Centers.

Date: March 22, 2004.

Time: 8 a.m. to 7:30 p.m.

Agenda: To review and evaluate grant applications.

Place: Double Tree Rockville, 1750 Rockville Pike, Rockville, MD 20852.

Contact Person: Khursheed Asghar, PhD, Chief, Basic Sciences Review Branch, Office of Extramural Affairs, National Institute on Drug Abuse, NIH, DHHS, Room 200, MSC 8401, 6101 Executive Boulevard, Bethesda, MD 20892–8401, (301) 443–2755.

(Catalogue of Federal Domestic Assistance Program Nos. 93.277, Drug Abuse Scientist Development Award for Clinicians, Scientist Development Awards, and Research Scientist Awards; 93.278, Drug Abuse National Research Service Awards for Research Training; 93.279, Drug Abuse Research Programs, National Institutes of Health, HHS)

Dated: January 23, 2004.

LaVerne Y. Stringfield,

Director, Office of Federal Advisory Committee Policy.

[FR Doc. 04–1996 Filed 1–29–04; 8:45 am]

BILLING CODE 4140–01–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Neurological Disorders and Stroke; Amended Notice of Meeting

Notice is hereby given of a change in the meeting of the National Advisory Neurological Disorders and Stroke Council, February 12, 2004, 8 a.m. to February 12, 2004, 10 a.m., National Institutes of Health, Building 1, Wilson Hall, 1 Center Drive, Bethesda, MD 20892, which was published in the **Federal Register** on January 16, 2004, FR69 04–1019.

The Clinical Trials Subcommittee will be in open session from 8–9 a.m., and will be in closed session from 9–10 a.m. The meeting is partially closed to the public.

Dated: January 23, 2004.

LaVerne Y. Stringfield,

Director, Office of Federal Advisory Committee Policy.

[FR Doc. 04–1997 Filed 1–29–04; 8:45 am]

BILLING CODE 4140–01–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Neurological Disorders and Stroke; Amended Notice of Meeting

Notice is hereby given of a change in the meeting of the National Advisory Neurological Disorders and Stroke Council, February 11, 2004, 8 p.m. to February 11, 2004, 10 p.m., Hyatt Regency Bethesda, One Bethesda Metro Center, 7400 Wisconsin Avenue, Bethesda, MD 20814 which was published in the **Federal Register** on January 16, 2004, FR 69 04–949.

The infrastructure, Neuroinformatics and Computational Neuroscience Subcommittee will be in open session from 8–9:30 p.m. and will be in closed session from 9:30–10 p.m. The meeting is partially closed to the public.

Dated: January 23, 2004.

LaVerne Y. Stringfield,

Director, Office of Federal Advisory Committee Policy.

[FR Doc. 04–1998 Filed 1–29–04; 8:45 am]

BILLING CODE 4140–01–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Library of Medicine; 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 Library of Medicine Special Emphasis Panel, G08 Grant Application.

Date: February 4, 2004.
Time: 1 p.m. to 2 p.m.
Agenda: To review and evaluate grant applications.
Place: National Library of Medicine, 6705 Rockledge Drive, Suite 301, Bethesda, MD 20817, (Telephone Conference Call).
Contact Person: Hua-Chuan Sim, MD, Health Science Administrator, National Library of Medicine, Extramural Programs, Bethesda, MD 20892.

This notice is being published less than 15 days prior to the meeting due to the urgent need to meet timing limitations imposed by the intramural research review cycle.

(Catalogue of Federal Domestic Assistance Program Nos. 93.879, Medical Library Assistance, National Institutes of Health, HHS)

Dated: January 23, 2004.

LaVerne Y. Stringfield,

Director, Office of Federal Advisory Committee Policy.

[FR Doc. 04–1999 Filed 1–29–04; 8:45 am]

BILLING CODE 4140–01–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Library of Medicine; 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 Library of Medicine Special Emphasis Panel, R01 & P41.
Date: March 16, 2004.
Time: 1 p.m. to 2 p.m.
Agenda: To review and evaluate grant applications.
Place: National Library of Medicine, 6705 Rockledge Drive, Suite 301, Bethesda, MD 20817, (Telephone Conference Call).
Contact Person: Hua-Chuan Sim, MD, Health Science Administrator, National Library of Medicine, Extramural Programs, Bethesda, MD 20892.

(Catalogue of Federal Domestic Assistance Program Nos. 93.879, Medical Library Assistance, National Institutes of Health, HHS)

Dated: January 23, 2004.

LaVerne Y. Stringfield,

Director, Office of Federal Advisory Committee Policy.

[FR Doc. 04–2000 Filed 1–29–04; 8:45 am]

BILLING CODE 4140–01–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Library of Medicine; 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 Library of Medicine Special Emphasis Panel Publications (G13).
Date: March 26, 2004.
Time: 8 a.m. to 5 p.m.
Agenda: To review and evaluate grant applications.
Place: Embassy Suites at the Chevy Chase Pavilion, 4300 Military Road, NW., Washington, DC 20015.
Contact Person: Hua-Chuan Sim, MD, Health Science Administrator, National Library of Medicine, Extramural Programs, Bethesda, MD 20892.

(Catalogue of Federal Domestic Assistance Program Nos. 93.879, Medical Library Assistance, National Institutes of Health, HHS)

Dated: January 23, 2004.

LaVerne Y. Stringfield,

Director, Office of Federal Advisory Committee Policy.

[FR Doc. 04–2001 Filed 1–29–04; 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, Icohrta Site Visit Reviews.
Date: January 30, 2004.
Time: 9 a.m. to 1 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: Hilary Sigmon, PhD, RN, Scientific Review Administrator, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 5216, MSC 7852, Bethesda, MD 20892, (301) 594–6377, *sigmonh@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, Software Maintenance.
Date: February 9, 2004.
Time: 8:30 a.m. to 5 p.m.
Agenda: To review and evaluate grant applications.
Place: Swissotel Washington, the Watergate, 2650 Virginia Avenue, NW., Washington, DC 20037.
Contact Person: Marc Rigas, PhD, Scientific Review Administrator, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Rm. 4194, MSC 7826, Bethesda, MD 20892–7826, (301) 402–1074, *rigasm@mail.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, ZRG1 ONC–O (29): DBBD Minority and Disability Predoctoral F31.
Date: February 11–12, 2004.
Time: 8 a.m. to 6 p.m.
Agenda: To review and evaluate grant applications.
Place: Double Tree Rockville, 1750 Rockville Pike, Rockville, MD 20852.
Contact Person: Neal B. West, PhD, Scientific Review Administrator, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 2114, MSC 7804, Bethesda, MD 20892, (301) 435–2633, *westnea@csr.nih.gov*.

Name of Committee: Center for Scientific Review Special Emphasis Panel, Hyperthermia Treatment of BSC.

Date: February 11, 2004.
Time: 1:30 p.m. to 3:30 p.m.
Agenda: To review and evaluate grant applications.
Place: National Institutes of Health, Bethesda, MD 20892, (Telephone conference call).
Contact Person: Elaine Sierra-Rivera, PhD, Scientific Review Administrator, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 6184, MSC 7804, Bethesda, MD 20892. (301) 435–1779;*riverase@csr.nih.gov.*

Name of Committee: Cell Development and Function Integrated Review Group, Cell Development and Function 1.
Date: February 12–13, 2004.
Time: 8:30 a.m. to 4 p.m.
Agenda: To review and evaluate grant applications.
Place: Georgetown Suites, 1111 30th Street, NW., Washington, DC 20007.
Contact Person: Richard A. Currie, PhD, Scientific Review Administrator, National Institutes of Health, Center for Scientific Review, 6701 Rockledge Drive, Room 5128, MSC 7840, Bethesda, MD 20892. (301) 435–1219;*currieri@mail.gov.*

Name of Committee: Musculoskeletal, Oral, and Skin Sciences Integrated Review Group, Skeletal Biology Structure and Regeneration Study Section.
Date: February 22–24, 2004.
Time: 8 a.m. to 5 p.m.
Agenda: To review and evaluate grant applications.
Place: Holiday Inn Georgetown, 2101 Wisconsin Avenue, NW., Washington, DC 20007.
Contact Person: Daniel F. McDonald, PhD, Chief, Musculoskeletal, Oral, and Skin Sciences, IRG, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 4214, MSC 7814, Bethesda, MD 20892. (301) 435–1215;*macdonald@csr.nih.gov.*

Name of Committee: Cardiovascular Sciences Integrated Review Group, Cardiac Contractility, Hypertrophy, and Failure Study Section.
Date: February 23–24, 2004.
Time: 8 a.m. to 5 p.m.
Agenda: To review and evaluate grant applications.
Place: Holiday Inn Chevy Chase, 5220 Wisconsin Avenue, Chevy Chase, MD 20815.
Contact Person: Russell T. Dowell, PhD, Scientific Review Administrator, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 4128, MSC 7814, Bethesda, MD 20892. (301) 435–1850; *dowellr@csr.nih.gov.*

Name of Committee: Infectious Diseases and Microbiology Integrated Review Group, Bacteriology and Mycology Subcommittee 1.
Date: February 23–24, 2004.
Time: 8 a.m. to 5 p.m.
Agenda: To review and evaluate grant applications.
Place: Hyatt Regency Bethesda, One Bethesda Metro Center, 7400 Wisconsin Avenue, Bethesda, MD 20814.
Contact Person: Timothy J. Henry, PhD, Scientific Review Administrator, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 4180, MSC 7808, Bethesda, MD 20892. (301) 435–1147.

Name of Committee: Center for Scientific Review Special Emphasis Panel, ZRG1 MOSS–C 13B: SMALL Business: Rheumatology.
Date: February 24, 2004.
Time: 10 a.m. to 11:30 a.m.
Agenda: To review and evaluate grant applications.
Place: Wyndham City Center, 1143 New Hampshire Avenue, NW., Washington, DC 20037.
Contact Person: Harold M. Davidson, PhD, Scientific Review Administrator, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 4216, MSC 7814, Bethesda, MD 20892. (301) 435–1776 *davidson@csr.nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel, ZRG1 MOSS–C 12: Small Business: Dermatology.
Date: February 24, 2004.
Time: 12 p.m. to 2 p.m.
Agenda: To review and evaluate grant applications.
Place: Wyndham City Center, 1143 New Hampshire Avenue, NW., Washington, DC 20037.
Contact Person: Harold M. Davidson, PhD., Scientific Review Administrator, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 4216, MSC 7814, Bethesda, MD 20892. (301) 435–1776; *davidsoh@csr.nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel, Cancer Diagnostic and Treatment.
Date: February 26–27, 2004.
Time: 8 a.m. to 5 p.m.
Agenda: To review and evaluate grant applications.
Place: Hilton Washington Embassy Row, 2015 Massachusetts Ave., NW., Washington, DC 20036.
Contact Person: Hungyi Shau, PhD., Scientific Review Administrator, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 6214, MSC 7804, Bethesda, MD 20892. (301) 435–1720; *shauhung@csr.nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel, ZRG1 RES D (03): SEP for LIRR SRA Conflict Applications.
Date: February 26, 2004.
Time: 8 a.m. to 9 a.m.
Agenda: To review and evaluate grant applications.
Place: Wyndham Washington, DC, 1400 M Street, NW., Washington, DC 20005.
Contact Person: Everett E. Sinnett, PhD., Scientific Review Administrator, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 2178, MSC 7818, Bethesda, MD 20892. (301) 435–1016; *sinnett@nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel, Chemistry/Biophysics SBIR/STTR Panel.
Date: February 26–27, 2004.
Time: 8 a.m. to 5 p.m.
Agenda: To review and evaluate grant applications.
Place: Washington Terrace, 1515 Rhode Island Avenue, NW., Washington, DC 20005.
Contact Person: Vonda K. Smith, PhD., Scientific Review Administrator, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 4172, MSC 7806, Bethesda, MD 20892. (301) 435–1789; *smithvo@csr.nih.gov.*

Name of Committee: Surgery, Radiology and Bioengineering Integrated Review Group, Surgery and Bioengineering Study Section.
Date: February 26–27, 2004.
Time: 8 a.m. to 4 p.m.
Agenda: To review and evaluate grant applications.
Place: Holiday Inn Select Bethesda, 8120 Wisconsin Ave., Bethesda, MD 20814.
Contact Person: Dharam S. Dhindsa, DVM, PhD, Scientific Review Administrator, Surgery and Bioengineering Study Section, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 5110, MSC 7854, Bethesda, MD 20892. (301) 435–1174, *dhindsad@crs.nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel, Innate Immunity/Host Defense.
Date: February 26–27, 2004.
Time: 8 a.m. to 5 p.m.
Agenda: To review and evaluate grant applications.
Place: The Watergate Hotel, 1650 Virginia Avenue, NW., Washington, DC 20037.
Contact Person: Tina McIntyre, PhD, Scientific Review Administrator, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 4202 MSC7812, Bethesda, MD 20892. (301) 594–6375; *mcintyrt@csr.nih.gov.*

Name of Committee: Biochemical Sciences Integrated Review Group, Pathobiochemistry Study Section.
Date: February 26–27, 2004.
Time: 8 a.m. to 2 p.m.
Agenda: To review and evaluate grant applications.
Place: Four Points By Sheraton, 8400 Wisconsin Avenue, MD 20814.
Contact Person: Zakir Bengali, PhD, Scientific Review Administrator, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 5150, MSC 7482, Bethesda, MD 20892. (301) 435–1742; *bengaliz@csr.nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel, Bacterial Biodefense.
Date: February 26–27, 2004.
Time: 8 a.m. to 5 p.m.
Agenda: To review and evaluate grant applications.
Place: The Watergate Hotel, 2650 Virginia Avenue, NW., Washington, DC 20037.
Contact Person: Rolf Menzel, PhD, Scientific Review Administrator, National Institutes of Health, 6701 Rockledge Drive, Room 3196, MSC 7808, Bethesda, MD 20892. (301) 435–0952; *menzelro@csr.nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel, Nursing Science: Children and Families Study Section.
Date: February 26–27, 2004.
Time: 8:30 a.m. to 3 p.m.
Agenda: To review and evaluate grant applications.

Place: Bethesda Marriott Suites, 6711 Democracy Boulevard, Bethesda, MD 20817.

Cantact Person: Karin F. Helmers, PhD, Scientific Review Administrator, Center for Scientific Review/SNEM IRG, 6701 Rockledge Drive, Room 3166, MSC 7770, Bethesda, MD 20892. (301) 435–1017; *helmersk@csr.nih.gav.*

Name of Committee: Infectious Diseases and Microbiology Integrated Review Group, Experimental Virology Study Section.

Date: February 26–27, 2004.

Time: 8:30 a.m. to 5 p.m.

Agenda: To review and evaluate grant applications.

Place: Governor's House Hotel, 1615 Rhode Island Avenue, NW., Washington, DC 20036.

Cantact Person: Robert Freund, PhD, Scientific Review Administrator, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 3200, MSC 7808, Bethesda, MD 20892. (301) 435–1050; *freundr@csr.nih.gov.*

Name of Committee: Molecular, Cellular and Developmental Neuroscience Integrated Review Group, Neurotransporters, Receptors, and Calcium Signaling Study Section.

Date: February 26–27, 2004.

Time: 8:30 a.m. to 4 p.m.

Agenda: To review and evaluate grant applications.

Place: Ritz-Carlton Hotel at Pentagon City, 1250 South Hayes Street, Arlington, VA 22202.

Contact Person: Peter B. Guthrie, PhD, Scientific Review Administrator, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 4142, MSC 7850, Bethesda, MD 20892. (301) 435–1239; *guthriep@csr.nih.gov.*

Name of Committee: Health of the Population Integrated Review Group, Social Sciences and Population Studies Study Section.

Date: February 26–27, 2004.

Time: 8:30 a.m. to 4 p.m.

Agenda: To review and evaluate grant applications.

Place: Holiday Inn Select, 480 King Street, Alexandria, VA 22314.

Cantact Persan: Bob Weller, PhD, Scientific Review Administrator, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 3160, MSC 7770, Bethesda, MD 20892. (301) 435–0694; *weller@csr.nih.gov.*

Name of Committee: Risk, Prevention and Health Behavior Integrated Review Group, Psychosocial Risk and Disease Prevention Study Section.

Date: February 26–27, 2004.

Time: 8:30 a.m. to 6 p.m.

Closed: To review and evaluate grant applications.

Place: Marriott Baltimore Inner Harbor, 110 South Eutaw Street, Baltimore, MD 21201.

Cantact Person: Deborah L. Young-Hyman, PhD, Scientific Review Administrator, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 4188, MSC 7808, Bethesda, MD 20892. (301) 451–8008; *yaunghyd@csr.nih.gav.*

Name of Committee: Center for Scientific Review Special Emphasis Panel, Clinical Neuroimmunology and Brain Tumors Study Section.

Date: February 26–27, 2004.

Time: 8:30 a.m. to 5 p.m.

Agenda: To review and evaluate grant applications.

Place: Melrose Hotel, 2430 Pennsylvania Ave., NW., Washington, DC 20037.

Cantact Person: Jay Joshi, PhD, Scientific Review Administrator, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 5184, MSC 7846, Bethesda, MD 20892. (301) 435–1184; *jashij@csr.nih.gav.*

Name af Committee: Molecular, Cellular and Developmental Neuroscience Integrated Review Group, Neurodegeneration and Biology of Glia Study Section.

Date: February 26–27, 2004.

Time: 8:30 a.m. to 4 p.m.

Agenda: To review and evaluate grant applications.

Place: Radisson Barcello, 2121 P Street, NW., Washington, DC 20037.

Contact Persan: Toby Behar, PhD, Scientific Review Administrator, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 4136, MSC 7850, Bethesda, MD 20892. (301) 435–4433; *behart@csr.nih.gav.*

Name of Cammittee: Brain Disorders and Clinical Neuroscience Integrated Review Group, Neural Basis of Psychopathology, Addictions and Sleep Disorders Study Section.

Date: February 26–27, 2004.

Time: 8:30 a.m. to 5 p.m.

Agenda: To review and evaluate grant applications.

Place: Governor's House Hotel, 1615 Rhode Island Avenue, NW., Washington, DC 20036.

Contact Person: Jay Cinque, MS, Scientific Review Administrator, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 5186, MSC 7846, Bethesda, MD 20892. (301) 435–1252; *cinquej@csr.nih.gav.*

Name af Committee: Health of the Population Integrated Review, Behavioral Genetics and Epidemiology Study Section.

Date: February 26–27, 2004.

Time: 9 a.m. to 5:30 p.m.

Agenda: To review and evaluate grant applications.

Place: Hyatt Regency Bethesda, One Bethesda Metro Center, Bethesda, MD 20814.

Cantact Persan: Yvette M. Davis, VMD, MPH, Scientific Review Administrator, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 3152, MSC 7770, Bethesda, MD 20892. (301) 435–0906.

Name af Cammittee: Genetic Sciences Integrated Review Group, Mammalian Genetics Study Section.

Date: February 26–27, 2004.

Time: 9 a.m. to 1:30 p.m.

Agenda: To review and evaluate grant applications.

Place: Bethesda Marriott, 5151 Pooks Hill Road, Bethesda, MD 20814.

Contact Person: Cheryl M. Corsaro, PhD, Scientific Review Administrator, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 2204, MSC 7890, Bethesda, MD 20892. (301) 435–1045; *corsarac@csr.nih.gav.*

Name of Cammittee: Center for Scientific Review Special Emphasis Panel, Data Sharing and Collaboration Tools.

Date: February 27, 2004.

Time: 8 a.m. to 6 p.m.

Agenda: To review and evaluate grant applications.

Place: The Watergate Hotel, 2650 Virginia Avenue, Washington, DC 20037.

Cantact Persan: George W. Chacko, PhD, Scientific Review Administrator, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 4186, MSC 7806, Bethesda, MD 20892. (301) 435–1220; *chackage@csr.nih.gav.*

Name of Committee: Onocological Sciences Integrated Review Group, Tumor Cell Biology Study Section.

Date: February 29–March 2, 2004.

Time: 6:30 p.m. to 5 p.m.

Agenda: To review and evaluate grant applications.

Place: Churchill Hotel, 1914 Connecticut Avenue, NW., Washington, DC 20009.

Cantact Person: Angela Y. Ng, PhD, MBA, Scientific Review Administrator, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 6200, MSC 7804, (For courier delivery, use MD 20817), Bethesda, MD 20892. (301) 435–1715; *nga@csr.nih.gov.*

(Catalogue of Federal Domestic Assistance Program Nos. 93.306, Comparative Medicine; 93.333, Clinical Research, 93.306, 93.333, 93.337, 93.393–93.396, 93.837–93.844, 93.846–93.878, 93.892, 93.893, National Institutes of Health, HHS.)

Dated: January 23, 2004.

LaVerne Y. Stringfield,

Directar, Office af Federal Advisory Cammittee Palicy.

[FR Doc. 04–2002 Filed 1–29–04; 8:45 am]

BILLING CODE 4140–01–M

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

[Docket No. FR–4901–N–05]

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.

EFFECTIVE DATE: January 30, 2004.

FOR FURTHER INFORMATION CONTACT: Mark Johnston, 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: January 22, 2004.

John D. Garrity,

Office of Special Needs Assistance Programs.

[FR Doc. 04–1748 Filed 1–29–04; 8:45 am]

BILLING CODE 4210–29–M

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

[OR–115–5900–JE–MQ99; HAG 04–0043]

Notice of Availability of the Timbered Rock Fire Salvage and Elk Creek Watershed Restoration Final Environmental Impact Statement; Medford District, Oregon

AGENCY: Bureau of Land Management.

ACTION: Notice of availability.

SUMMARY: In accordance with Section 202 of the National Environmental Policy Act of 1970 (NEPA), a FEIS has been prepared by the Bureau of Land Management (BLM), Medford District, to analyze possible salvage opportunities resulting from the Timbered Rock Fire and proposed restoration projects designed to move resource conditions closer to the desired future conditions identified in the Medford District Resource Management Plan, Northwest Forest Plan, Elk Creek Watershed Analysis, and the South Cascades Late-Successional Reserve Assessment. The subject lands were designated Late-Successional Reserve in the Northwest Forest Plan. Restoration projects are designed to accelerate establishment or protection of late-successional forest conditions. Scientific debate surrounds the fire salvage issue and related NEPA documentation is continually challenged. In response to these disputes, an alternative was developed including scientific investigations that could be implemented within the Late-Successional Reserve to respond to these controversial issues related to salvage of fire-killed trees or fire effects on critical resources. The FEIS addresses whether to pursue salvage, levels of snags and coarse wood debris to be retained, and restoration projects on BLM-administered lands within and adjacent to the Late-Successional Reserve and Elk Creek Watershed.

DATES: The period of availability for public review of the FEIS ends 30 days after publication of the Environmental Protection Agency (EPA) Notice of Availability (NOA) in the **Federal Register**. At that time public comments will be reviewed and considered in the decision making process.

ADDRESSES: Written comments on the document should be addressed to Timbered Rock EIS, 3040 Biddle Road, Medford, Oregon, 97504; or e-mail *or110treis@or.blm.gov*. Copies will be available at the Jackson and Josephine County libraries, and on the Timbered Rock Fire Salvage and Elk Creek Watershed Restoration Web site at *http://www.or.blm.gov/Medford/TimbrockEIS/index.htm*. Copies of the FEIS will be mailed to individuals, agencies, or companies who previously requested copies. A limited number of copies of the document will be available at the Medford District Office, 3040 Biddle Road, Medford, Oregon, 97504. Pursuant to 7 CFR Part 1, Subpart B, Section 1.27, all written and electronic submissions in response to this notice, public scoping letters, and draft and final Environmental Impact Statements will be made available for public review at the Medford District Office during regular hours (7:45 a.m. to 4:30 p.m., Monday through Friday, except holidays) including the submitter's name and address.

Individuals may request confidentiality with respect to their name, address, and phone number. If you wish to have your name or street address withheld form public review, or from disclosure under the Freedom of Information Act, the first line of the comment should start with the words "CONFIDENTIALITY REQUESTED" in uppercase letters in order for the BLM to comply with your request. Such request will be honored to the extent allowed by law. Comments content will not be kept confidential. All submissions from organizations or businesses, and from individuals identifying themselves as representatives or officials of organizations or businesses will be available for public inspection in their entirety.

FOR FURTHER INFORMATION CONTACT: Jean Williams at (541) 944–6620 or John Bergin at (541) 840–9989.

SUPPLEMENTARY INFORMATION: The FEIS addresses seven alternatives for possible salvage opportunities and proposed restoration projects designed to move resource conditions closer to the desired future conditions identified in the Northwest Forest Plan, Elk Creek Watershed Analysis, and the South Cascades Late-Successional Reserve Assessment. Two types of salvage, area and roadside are discussed in Alternatives C through G. Alternatives A and B proposes no salvage. Alternatives C, D and G were designed using specific guidance relating to post-fire salvage and/or Late-Successional Reserve guidelines. Roadside salvage is designed to reduce existing or potential public safety concerns while recovering economic value. Included in the design of Alternative G, the Preferred Alternative, is research to evaluate mixed-species reforestation plantings to identify and characterize temporal patterns of vegetation structural development and species diversity; to assess temporal dynamics of fuels loading and fire risk; and to determine impacts of snag retention on survival and growth of planted and naturally regenerated trees. Also included in Alternative G is research designed to evaluate various snag retention levels on wildlife species (birds and small mammals).

Four levels of restoration projects are proposed in the six action alternatives: focused, moderate, extensive and focused within the fire perimeter only. The restoration varies by the scope of the projects (acres, miles of roads, etc.), intensity of the treatments, and location of the treatments. Restoration projects are located both within the Timbered Rock Fire perimeter and outside the fire area. Most projects are located within the Elk Creek Watershed; however, a proposed eagle nest project and some fuel management zone projects are located on ridge tops within adjacent watersheds. Projects are based on recommendations presented in the Late-Successional Reserve Assessment and/or Elk Creek Watershed Analysis, or were developed to address specific issues.

Projects proposed within the fire area focus on road projects to reduce existing and potential sedimentation from the road network, fish improvement projects, development of Fuel Management Zones, and reducing future hazardous fuel conditions within existing Northern Spotted Owl activity centers. Reforestation of the burned area was assessed in the Emergency Stabilization/Rehabilitation Plan Environmental Assessment. Alternatives A and E follow these recommendations.

Other approaches to reforestation are presented in Alternatives B, C, D, F, and G. A reforestation study is included which would evaluate a variety of planting densities, species, and follow-up treatments in both salvage and unsalvaged areas in alternative G. This reforestation research could be incorporated into any alternative. The FEIS analyzes in detail the following seven alternatives:

Alternative A—No Action—Continuation of current management, follow the Emergency Stabilization and Rehabilitation Plan as planned for the Timbered Rock Fire

No restoration projects are proposed, but rehabilitation and stabilization projects proposed in the Timbered Rock Fire Emergency Stabilization and Rehabilitation Project Environmental Assessment would be implemented.

Alternative B—No Salvage and Focused Restoration Emphasis

Emphasis is placed on reducing vegetative competition in over-stocked stands with density management treatments, fuels reduction treatments, and pine habitat restoration. Areas proposed for treatment are generally those in most need of reducing competing vegetation. Within the fire perimeter, restoration would focus on high priority road work. Restoration actions would focus on non-commercial projects, designed to accelerate the growth of trees in stands to promote late-successional conditions with a variety of size classes. Species diversity would be maintained to promote connectivity between owl activity sites and develop late-successional forest characteristics.

Alternative C—Salvage Following South Cascade Late-Successional Reserve Assessment Guidelines and Moderate Restoration Emphasis

Area salvage emphasis is proposed in high and moderate burn severity areas greater than 10 acres where the fire resulted in a stand-replacement event. Alternative C salvage is based on guidelines from the Late-Successional Reserve Assessment for snag and coarse woody debris retention. Area salvage on 247 acres and roadside hazard tree removal on 1,078 acres would harvest an estimated 8.6 million board feet (MMBF). Restoration projects include fish habitat improvement, Late-Successional Reserve thinning, pine and oak woodlands restoration, reforestation of stand-replacement areas greater than 5 acres, fuels reduction along ridgelines, wildlife habitat enhancement projects, and road improvement projects.

Alternative D—Late-Successional Reserve Guidelines for Salvage Using DecAID Wood Advisor Tool for Snags and Course Woody Debris (CWD) and Moderate Restoration Emphasis

Area salvage emphasis is proposed in high and moderate burn severity areas greater than 10 acres where the fire resulted in a stand-replacement event. Instead of following LSRA salvage guidelines, snag and coarse woody debris retention levels in this alternative are based on the DecAID Wood Advisor tool. Area salvage on 820 acres and roadside hazard tree removal on 1,064 acres would harvest an estimated 21.0 MMBF. Restoration projects would be the same as Alternative C.

Alternative E—High Level of Salvage and Extensive Restoration Emphasis

Area salvage emphasis is proposed in high, moderate, low and very low burned severity areas. Area salvage on 3,269 acres and roadside hazard tree removal on 536 acres would harvest an estimated 29.4 MMBF. Snag retention levels within the high and moderate burn severity areas would be 6–14 snags/acre. This is based on study by Haggard and Gaines (2001) which found the highest diversity in cavity nesting species and the highest number of nests where snag densities ranged from 6–14 snags/acre. Snag retention within the low and very low burn severity areas with canopy cover greater than 40 percent would be 4 snags/acre. The course woody debris level in this alternative would be a minimum of 120 linear feet/acre. Extensive restoration would increase the scope of the projects (acres, miles of roads, etc.), intensity of the treatments, and location of the treatments identified in Alternative C and D. Alternative E also proposes seasonal closure of some roads.

Alternative F—Salvage Logging and Post-fire rehabilitation actions consistent with report on Recommendations for Ecologically Sound Post-Fire Salvage Management and Other Post-Fire Treatments on Federal Lands in the West (Beschta, *et al.* 1995)

Area salvage emphasis is based on recommendations to avoid severely burned areas, erosive sites, fragile soils, riparian areas, steep slopes, or sites where accelerated erosion is possible. Existing snags and course woody debris levels would be retained on all these areas. Salvage would occur in 3–10 acre patches of fire-killed trees. Within each of these patches, a minimum of 2 acres would be reserved from salvage, retaining all snags and course woody debris. Area salvage on 213 acres and roadside hazard tree removal on 1,182 acres would harvest an estimated 8.0 MMBF. The Beschta, *et al.* report does not address actions outside of a burned area. As a result, no Late-Successional Reserve restoration actions are proposed. However, restoration projects within the fire perimeter, consistent with Beschta, *et al.* report are proposed.

Alternative G—Preferred Alternative—Salvage Including Research and Moderate Restoration Emphasis

Alternative G includes two approaches to area salvage; research based and salvage of those areas remaining. Research area salvage emphasis is designed to study the effects of various snag levels on selected wildlife species (birds and small mammals). Twelve units were selected to be included in this study. These units are generally 30 acres or greater. Four units would be salvaged leaving six snags per acre greater than 20″ diameter at breast height (DBH). Another four units would salvage 70 percent of the unit leaving six snags per acre greater than 20 DBH, with the remaining 30 percent being unsalvaged. In addition, four control units would not be salvaged. Salvage would be on 282 acres for an estimated 7.4 MMBF. A reforestation study is also included, which would evaluate a variety of planting densities, species, and follow-up treatments in both salvaged and unsalvaged areas. The remaining area salvage would focus on stand replacement areas (high and moderate burn severity) greater than 10 acres. Salvage would be on 679 acres and roadside hazard tree removal on 1,188 acres would harvest an estimated 16.0 MMBF.

Snag and course woody debris levels would meet DecAid Wood Advisor recommendations. Retained snags would be clumped together, instead of scattered throughout the unit. Restoration projects would be the same as Alternatives C and D. Alternative G also proposes seasonal closure of some roads.

The information contained in the Final EIS has been updated based upon new information collected since publication of the DEIS and to add clarity based upon public comments or internal review. In addition, letters received during the public comment period and our responses to substantive comments have been incorporated into the Final EIS as Chapter 5.

It is not the intent of this project to change land use allocations, nor

Standard and Guidelines made through the Northwest Forest Plan and later adopted through the Medford District Resource Management Plan. Alternative G, the Preferred Alternative, has been determined to be consistent with the Northwest Forest Plan and Medford District Resource Management Plan.

Timothy B. Reuwsaat,

Medford District Manager.

[FR Doc. 04–2049 Filed 1–29–04; 8:45 am]

BILLING CODE 4310–33–P

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

[AK–025–04–1610–DO–089L]

Notice of Intent To Prepare a Resource Management Plan and Associated Environmental Impact Statement for the Kobuk-Seward Peninsula Planning Area

AGENCY: Bureau of Land Management, Interior.

ACTION: Notice of Intent to prepare a Resource Management Plan (RMP) with an associated Environmental Impact Statement (EIS) for the Kobuk-Seward Peninsula planning area in western Alaska.

SUMMARY: This document provides notice that the Bureau of Land Management (BLM) intends to prepare an RMP for the Kobuk-Seward Peninsula planning area, which includes public lands and resources managed by the Northern Field Office. This action will require a single EIS. The planning area includes approximately 13 million acres of BLM-administered lands in western Alaska and encompasses the area from Point Lay south to the Norton Sound, and from the Bering and Chukchi seas east to the Kobuk River. It includes the Seward Peninsula east to the Nulato Hills. The plan will fulfill the needs and obligations set forth by the National Environmental Policy Act (NEPA), the Federal Land Policy and Management Act (FLPMA), and BLM management policies. The BLM will work collaboratively with interested parties to identify the management decisions that are best suited to local, regional, and national needs and concerns. The public scoping process will identify planning issues and develop planning criteria.

DATES: The public scoping period will begin upon publication of this notice. Formal scoping will end 90 days after publication of this notice. Comments on issues and planning criteria can be submitted in writing to the address listed below. All public meetings will be announced through the local news media and the BLM Web site (*http://aurora.ak.blm.gov/*) at least 15 days prior to the event. The minutes and list of attendees for each meeting will be available to the public and open for 30 days to any participants who wish to clarify the views they expressed.

Public Participation: Public meetings will be held throughout the plan scoping and preparation period. In order to ensure local community participation and input, public meetings will be held in several communities within the planning area. Early participation is encouraged and will help determine the future management of BLM-administered lands within the planning area. In addition to the ongoing public participation process, formal opportunities for public participation will be provided through comment on the alternatives and upon publication of the BLM draft RMP/EIS.

ADDRESSES: Written comments should be sent to: Field Manager, Kobuk-Seward Peninsula Resource Management Planning, Bureau of Land Management, Northern Field Office, 1150 University Avenue, Fairbanks, Alaska, 99709–3844; Fax (907)-474-2282. Comments, including names and street addresses of respondents, will be available for public review at the Northern Field Office during regular business hours 7:30 a.m. to 4:30 p.m., Monday through Friday, except holidays, and may be published as part of the EIS. Individual respondents may request confidentiality. If you wish to withhold your name or street address from public review or from disclosure under the Freedom of Information Act, you must state this prominently at the beginning of your written comment. Such requests will be honored to the extent allowed by law. All submissions from organizations and businesses, and from individuals identifying themselves as representatives or officials or organizations or businesses, will be available for public inspection in their entirety.

FOR FURTHER INFORMATION CONTACT: For further information and/or to have your name added to our mailing list, contact Jeanie Cole by telephone at (907) 474–2340 or via e-mail at *jeanie_cole@blm.gov.*

Dated: January 12, 2004.

Susan M. Will,

Acting Manager, Northern Field Office.

[FR Doc. 04–2050 Filed 1–29–04; 8:45 am]

BILLING CODE 4310–JA–P

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

[CA–610–04–1220–AA]

Meeting of the California Desert District Advisory Council

SUMMARY: Notice is hereby given, in accordance with Public Laws 92–463 and 94–579, that the California Desert District Advisory Council to the Bureau of Land Management, U.S. Department of the Interior, will participate in a field tour of the BLM-administered public lands on Friday, April 23, 2004, from 8 a.m. to 5 p.m., and meet in formal session on Saturday, April 24, from 8 a.m. to 4 p.m. The Saturday meeting will be held at the Needles City Council Chambers, located 1111 Bailey, Needles, California.

The Council and interested members of the public will assemble for a field tour at the parking lot of the Best Western Colorado River Inn at 7:45 a.m. and depart 8 a.m. The Inn is located at 2371 West Broadway in Needles, California. Tour stops will include a dedication of a Route 66 interpretive display and a BLM grazing allotment. Presentations and discussions will focus on current grazing management and proposed revisions to the grazing regulations. The public is welcome to participate in the tour, but should plan on providing their own transportation, drinks, and lunch.

Agenda items for the Saturday Council meeting will include an update on the West Mojave Plan, reports by Council members serving on the grazing technical review team (TRT) and the Imperial Sand Dunes TRT, Council recommendations to Secretary of the Interior Gail Norton regarding the proposed revisions of BLM's grazing regulations, an overview to the Desert Manager's Group annual work plan, and a tentative presentation on the Clark County (Nevada) Habitat Conservation Plan.

All Desert District Advisory Council meetings are open to the public. Time for public comment may be made available by the Council Chairman during the presentation of various agenda items, and is scheduled at the end of the meeting for topics not on the agenda.

Written comments may be filed in advance of the meeting for the California Desert District Advisory Council, c/o Bureau of Land Management, Public Affairs Office, 22835 Calle San Juan De Los Lagos, Moreno Valley, California 92553. Written comments also are accepted at the time of the meeting and, if copies are provided to the recorder, will be incorporated into the minutes.

FOR FURTHER INFORMATION CONTACT: Doran Sanchez, BLM California Desert District Public Affairs Specialist (909) 697–5220.

Dated: January 21, 2004.

Linda Hansen,

District Manager.

[FR Doc. 04–1960 Filed 1–29–04; 8:45 am]

BILLING CODE 4310–40–P

DEPARTMENT OF THE INTERIOR

Minerals Management Service

Outer Continental Shelf (OCS), Alaska Region, Chukchi Sea/Hope Basin

AGENCY: Minerals Management Service (MMS), Interior.

ACTION: Call for Information and Nominations.

SUMMARY: The Secretary's decision to consider offering the Chukchi Sea/Hope Basin planning area in the OCS Oil and Gas Leasing Program for 2002–2007 provides for an 18-month "special-interest" process beginning with publication of this Call. Based on the information and specific nominations received as a result of this Call, a decision will be made whether to proceed with a sale.

DATES: Nominations and comments on the Call must be received no later than April 29, 2004.

FOR FURTHER INFORMATION CONTACT: Please call Tom Warren at (907) 271–6691 in MMS's Alaska OCS Region regarding questions on the Call.

SUPPLEMENTARY INFORMATION: The objective of this "special-interest" leasing option is to foster exploration in a frontier OCS area of potential, but high economic cost, without investment of the considerable time and effort required for holding a typical lease sale. The general approach is to query industry regarding the level of interest in proceeding with a sale in the Chukchi Sea/Hope Basin that would offer only very small, very focused areas of specific interest for exploration and to request nominations of such areas. The lease sale is being proposed to provide opportunities for industry to pursue the high resource potential of the Chukchi Sea area in conjunction with potential natural gas resources that may extend into the adjacent Hope Basin area. We also request comments from the general public on this special-interest leasing process, including the terms and conditions of a sale. The MMS will consider all comments and nominations in the decision on whether and where within the Chukchi Sea/Hope Basin to proceed with leasing and on the terms and conditions of a lease sale proposal. A decision to offer a nominated area for leasing will depend on a commitment from industry to explore the area leased within a specific time period.

This is the second Call issued for the Chukchi Sea/Hope Basin for this 5-year program. The first Call was published in the **Federal Register** on March 25, 2003. No interest was expressed; therefore, the process was stopped and deferred to this year. If no interest is expressed in response to this Call, the MMS will defer the sale for one year and reissue the Call the following year. This process will continue throughout the 5-year program until there is sufficient interest to proceed with the planning steps toward a sale. No more than two rounds of lease issuance in the Chukchi Sea/Hope Basin would occur during this 5-year program.

This Call does not indicate a preliminary decision to lease in the area described below. If the MMS decides to proceed with the sale process, the MMS will make the final decision on the specific areas for possible leasing at a later date in the presale process and in compliance with the 5-year program and with applicable laws including all requirements of the National Environmental Policy Act (NEPA) and the OCS Lands Act (OCSLA). The MMS may adjust the dimensions of a nominated area after discussions with the nominating company.

Call for Information and Nominations

1. Authority

This Call is published pursuant to the OCS Lands Act, as amended (43 U.S.C. 1331–1356, [1994]), and the regulations issued thereunder (30 CFR part 256 and 30 CFR part 260); and in accordance with the OCS Oil and Gas Leasing Program 2002 to 2007, approved June 27, 2002.

2. Purpose of Call

The purpose of the Call is to gather preliminary information, to request nomination of specific areas of interest to industry, and to request comments on the terms and conditions of offering these special-interest lands. The Call also serves to initiate public outreach to assist in preparation of the NEPA analysis for this proposal. This proposal is in keeping with Sec. 102(9) of the OCS Lands Act Amendments of 1978, which states as a purpose of the statute, "* * *to insure that the extent of oil and natural gas resources of the OCS is assessed at the earliest practicable time." The objective of the "special-interest" leasing process is to encourage exploration in a frontier OCS area that might contain natural gas for potential use in local communities, as well as oil to meet national energy needs. The sale would offer for lease both oil and gas.

We seek comments, information, and nominations on oil and gas leasing, exploration, and development and production within the Chukchi Sea/Hope Basin are sought from all interested parties. We also seek comments on the terms, conditions, and economic incentives of a sale in the Chukchi Sea/Hope Basin. We strongly encourage industry and other interested parties to contact the MMS, Alaska OCS Region, Mr. Tom Warren at (907) 271–6691, with questions or to discuss interest in the area. This early planning and consultation step is particularly important to this special-interest lands process. The MMS will base its decision on whether to proceed with the presale process and the terms and conditions of a sale on the nominations and other information received in response to this Call. This process will ensure a decision that considers the concerns of all respondents in future decisions in this leasing process pursuant to the OCS Lands Act and regulations at 30 CFR part 256 and 30 CFR part 260. We also encourage commenters to submit comments and suggestions on the "special-interest" leasing process in general using this process.

This Call is being issued in accordance with the OCS Oil and Gas Leasing Program 2002 to 2007, approved June 27, 2002. The program offers two sales in the Chukchi Sea/Hope Basin during the 5-year program. If no interest is expressed in response to this Call, the MMS will defer the sale for one year and reissue the Call the following year. This process will continue throughout the 5-year program until there is sufficient interest to proceed with the planning steps toward a sale. No more than two rounds of lease issuance in the Chukchi Sea/Hope Basin would occur during this 5-year program.

3. Description of Area

The area subject to this Call is located offshore the State of Alaska in the Chukchi Sea, between Cape Krusenstern and Point Barrow. The Chukchi Sea area consists of approximately 6,155 whole and partial blocks (about 34 million acres). It extends offshore from about 10 to approximately 200 miles in water depths from about 32 feet to approximately 230 feet. A small portion of the northeast corner of the area drops to approximately 3,000 feet. The Hope Basin area consists of approximately

1,243 whole and partial blocks (about 6 1/2 million acres). It extends offshore from about 3 to approximately 110 miles in water depths from about 32 feet to approximately 230 feet.

A page-size map of the area accompanies this Notice. A large scale Call map showing the boundaries of the area on a block-by-block basis is available without charge from the Public Information Office at the address given below, or by telephone request at (907) 271–6438 or 1–800–764–2627. Copies of Official Protraction Diagrams (OPDs) are also available for $2 each.

Alaska OCS Region, Minerals Management Service, 949 East 36th Avenue, Room 308, Anchorage, Alaska 99508–4302, *akwebmaster@mms.gov.*

4. Instructions on Call

The Call for Information Map and indications of interest and/or comments must be submitted to the Regional Supervisor, Leasing and Environment, at the above address.

The Call map delineates the area that is the subject of this Call. Respondents are requested to indicate very specific areas of interest in and comment on the Federal acreage within the boundaries of the Call area that they wish to have included in a proposed sale in the Chukchi Sea/Hope Basin.

If you wish to comment, you may submit your comments by any one of the following methods:

- You may mail comments to the Alaska OCS Region, Minerals Management Service, 949 East 36th Avenue, Room 308, Anchorage, Alaska 99508–4302.
- You may also comment via e-mail to *callforinformation@mms.gov.* Please submit Internet comments as an ASCII file avoiding the use of special characters and any form of encryption. Please also include "Attn: Comments on Call for Information and Nominations for Proposed 2005 Lease Sale in the Chukchi Sea/Hope Basin" and your name and return address in your Internet message.
- Finally, you may hand deliver comments to the Alaska OCS Region, Minerals Management Service, 949 East 36th Avenue, Room 308, Anchorage, Alaska 99508–4302.

Our practice is to make comments, including names and addresses of respondents, available for public review during regular business hours. Individual respondents may request that we withhold their address from the rulemaking record, which we will honor to the extent allowable by law. Under certain circumstances we can withhold a respondent's identity, as allowable by law. If you wish us to withhold your name and/or address, you must state this prominently at the beginning of your comment. However, we will not consider anonymous comments. We will make all submissions from organizations or businesses, and from individuals identifying themselves as representatives or officials of organizations or businesses, available for public inspection in their entirety.

A. *Areas of Interest to the Oil and Gas Industry.* Industry must be candid and very specific regarding the areas they nominate if this process is to succeed. The purpose of this process is to identify and offer only small-focused areas where industry has a significant interest in exploration. Nominations covering large-scale areas will not be helpful in defining these areas.

Nominations must be depicted on the Call map by outlining the area(s) of interest along block lines. Nominators are asked to submit a list of whole and partial blocks nominated (by OPD and block number) to facilitate correct interpretation of their nominations on the Call map. Although the identities of those submitting nominations become a matter of public record, the individual nominations are proprietary information. The telephone number and the name of a person to contact in the nominator's organization for additional information should be included in the response. This person will be contacted to set up a mutually agreeable time and place for a meeting with the Alaska OCS Regional Office to present their views regarding the company's nominations.

B. *Terms, Conditions, and Economic Incentives Pertaining to Lease Issuance.* We request respondents to comment on the terms, conditions, and economic incentives pertaining to lease issuance for any leases that may be issued as a result of a sale in the Chukchi Sea/Hope Basin. The MMS is aware of the lack of infrastructure and distance from shore to some of the blocks in this area and will consider these factors in designing any incentives. The following are being considered for use in this sale:

- Lease term of 10 years
- Submission of an exploration plan within 8 years of lease issuance
- Economic incentives similar in form to those contained in the Notice of Sale for Beaufort Sea Sale 186 (68 FR 50549). Incentives for Beaufort Sea Sale 186 were:
  - Royalty suspension volumes for oil production (with possible consideration for gas)
  - Reduced rental rates
  - Lower minimum bid requirements

C. *Relation to Coastal Management Plans (CMPs).* We also seek comments on potential conflicts with approved local CMPs that may result from the proposed sale and future OCS oil and gas activities. These comments should identify specific CMP policies of concern, the nature of the conflicts foreseen, and steps that MMS could take to avoid or mitigate the potential conflicts. Comments may be in terms of broad areas or restricted to particular blocks of concern. We request commenters to list block numbers or outline the subject area on the large-scale Call map.

5. Use of Information From Call

Information submitted in response to this Call will be used for several purposes. We will use responses to:

- Determine whether to proceed with a competitive oil and gas lease sale in the Chukchi Sea/Hope Basin
- Identify specific areas of interest for oil and/or gas exploration and development
- Identify environmental effects and potential use conflicts
- Assist in the public outreach for the environmental analysis
- Develop possible alternatives to the proposed action
- Develop lease terms and conditions/mitigating measures
- Identify potential conflicts between oil and gas activities and the Alaska CMP

6. Existing Information

An extensive environmental, social, and economic studies program has been underway in the Alaska OCS Region since 1976, including studies in this area. The emphasis has been on geologic mapping, environmental characterization of biologically sensitive habitats, endangered whales and marine mammals, physical oceanography, ocean-circulation modeling, and ecological and socio-cultural effects of oil and gas activities.

The MMS has had two past sales in the Chukchi Sea area. In May 1988, Sale 109 was held and resulted in 350 leases being issued. In August 1991, Sale 126 was held and resulted in 28 leases being issued. There were four exploratory wells drilled, but all have been permanently plugged and abandoned. All 378 leases have since been relinquished or expired. No lease sales have been held in the Hope Basin area. The Alaska OCS Region document "Undiscovered Oil and Gas Resources, Alaska Federal Offshore, December 2000 Update" (*http://www.mms.gov/alaska/re/uogr.pdf*), estimates the undiscovered conventionally recoverable resources at:

Area	Oil and NGL (BBO)			Gas (TCFG)			BOE (BBO)			MPhc
	F95	Mean	F05	F95	Mean	F05	F95	Mean	F05	
CHUKCHI SHELF	8.60	15.46	25.03	13.56	60.11	154.31	11.32	26.21	49.60	1.00
HOPE BASIN	0.00	0.09	0.28	0.00	3.38	11.06	0.00	0.69	2.25	0.61

BBO, billions of barrels of oil and natural gas liquids; TCFG, trillions of cubic feet; BOE, total oil and gas in billions of energy-equivalent barrels (5,620 cubic feet of gas=1 energy-equivalent barrel of oil); reported MEAN, resource quantities at the mean in cumulative probability distributions; F95, the resource quantity having a 95-percent probability of being met or exceeded; F05, the resource quantity having a 5-percent probability of being met or exceeded; MPhc, marginal probability for hydrocarbons for basin, i.e., chance for the existence of at least one pool of undiscovered, conventionally recoverable hydrocarbons somewhere in the basin. Resource quantities shown are risked, that is, they are the product of multiplication of conditional resources and Mphc. All liquid resources in Norton basin are natural gas liquids that would only be recovered by natural gas production.

Information on the studies program, completed studies, and a program status report for continuing studies in this area may be obtained from the Chief, Environmental Studies Section, Alaska OCS Region, by telephone request at (907) 271–6577, or by written request at the address stated under Description of Area. A request may also be made via the Alaska OCS Region Web site at *http://www.mms.gov/alaska/ref/pubindex/pubsindex.htm.*

7. Tentative Schedule

If MMS receives specific nominations from industry in response to this Call and decides to proceed with the pre-sale process, the following is a list of tentative milestone dates applicable to a Chukchi Sea/Hope Basin sale in 2005:

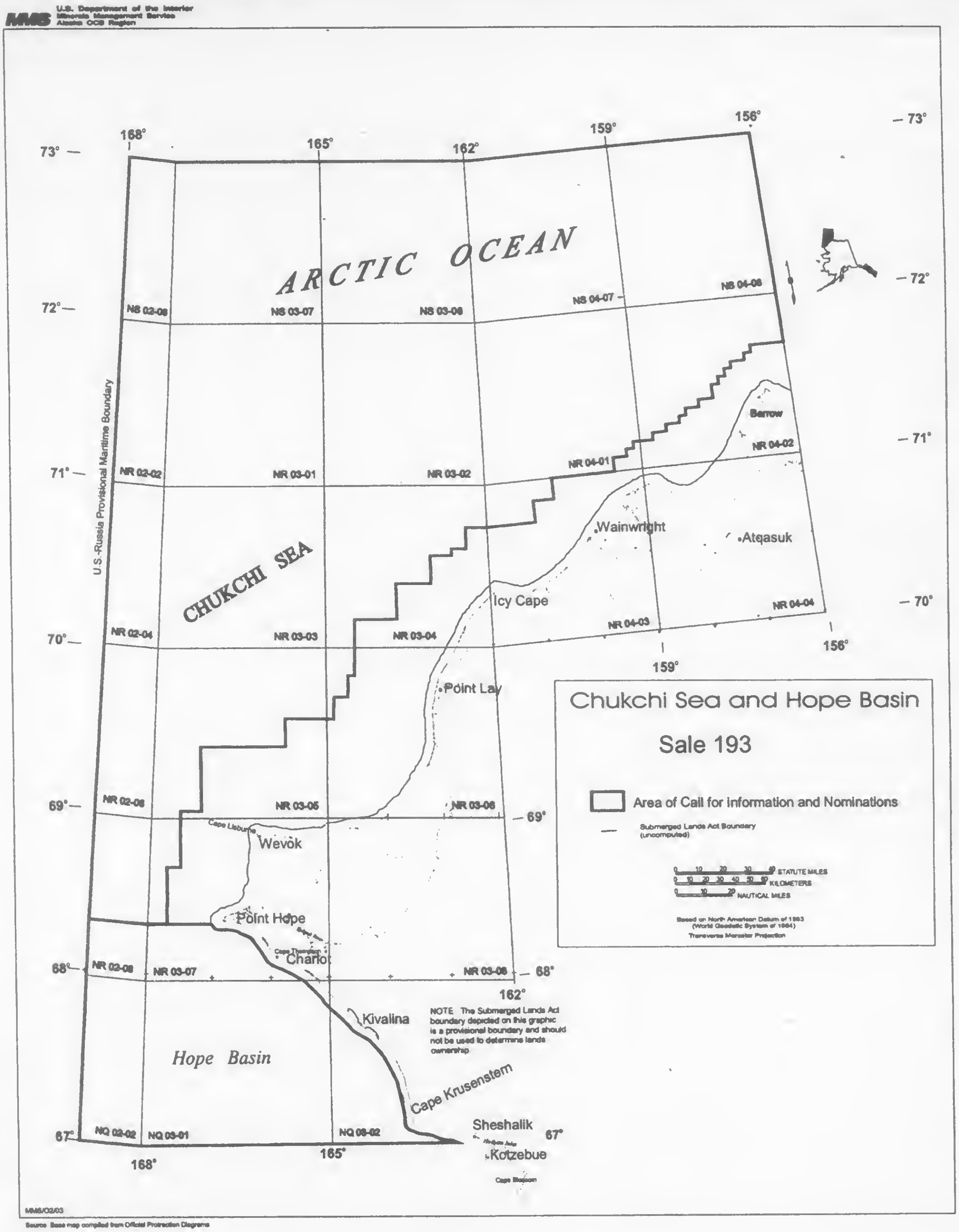
	Tentative process milestones for proposed 2005 Chukchi Sea/Hope Basin Sale
Call published/public outreach initiated	January 2004.
Comments due on Call	April 2004.
Decision whether to proceed/Area Identification	May 2004.
NEPA analysis	February 2005.
Consistency Determination/Proposed Notice of Sale	April 2005.
Governor's Comments due	June 2005.
Final Notice of Sale published	August 2005.
Sale	September 2005.

Dated: January 20, 2004.

R.M. Burton,

Director, Minerals Management Service.

BILLING CODE 4310–MR–P


MMS
U.S. Department of the Interior
Minerals Management Service
Alaska OCS Region
ARCTIC OCEAN
CHUKCHI SEA
U.S.-Russia Provisional Maritime Boundary
73°
72°
71°
70°
69°
68°
67°
168°
165°
162°
159°
156°
NS 02-08
NS 03-07
NS 03-08
NS 04-07
NS 04-08
NR 02-02
NR 03-01
NR 03-02
NR 04-01
NR 04-02
NR 02-04
NR 03-03
NR 03-04
NR 04-03
NR 04-04
NR 02-06
NR 03-05
NR 03-06
NR 02-08
NR 03-07
NR 03-08
NQ 02-02
NQ 03-01
NQ 03-02
Barrow
Wainwright
Atqasuk
Icy Cape
Point Lay
Cape Lisburne
Wevok
Point Hope
Charlot
Kivalina
Hope Basin
Cape Krusenstern
Sheshalik
Kotzebue
Chukchi Sea and Hope Basin
Sale 193
Area of Call for information and Nominations
Submerged Lands Act Boundary (uncomputed)
STATUTE MILES
KILOMETERS
NAUTICAL MILES
Based on North American Datum of 1983 (World Geodetic System of 1984)
Transverse Mercator Projection
NOTE The Submerged Lands Act boundary depicted on this graphic is a provisional boundary and should not be used to determine lands ownership
MMS/02/03
Source: Base map compiled from Official Protraction Diagrams

[FR Doc. 04–2010 Filed 1–29–04; 8:45 am]

BILLING CODE 4310–MR–C

DEPARTMENT OF THE INTERIOR

Minerals Management Service

Outer Continental Shelf (OCS), Alaska Region, Norton Basin

AGENCY: Minerals Management Service (MMS), Interior.

ACTION: Call for information and nominations.

SUMMARY: The Secretary's decision to consider offering the Norton Basin planning area in the OCS Oil and Gas Leasing Program for 2002–2007 provides for an 18-month "special-interest" process beginning with publication of this Call. Based on the information and specific nominations received as a result of this Call, a decision will be made whether to proceed with a sale.

DATES: Nominations and comments on the Call must be received no later than 90 days after publication of this document in the **Federal Register**.

FOR FURTHER INFORMATION CONTACT: Please call Tom Warren at (907) 271–6691 in MMS's Alaska OCS Region regarding questions on the Call.

SUPPLEMENTARY INFORMATION: The objective of this "special-interest" leasing option is to foster exploration in a high-cost frontier OCS area remote from oil and gas infrastructure without investment of the considerable time and effort required for holding a typical lease sale. The general approach is to query industry regarding the level of interest in proceeding with a sale in the Norton Basin that would offer only very small, very focused areas of specific interest for exploration and to request nominations of such areas. Norton Basin may contain quantities of natural gas, which might be used for western Alaska communities if economically feasible. We also request comments from the general public on this special-interest leasing process, including the terms and conditions of a sale. The MMS will consider all comments and nominations in the decision on whether and where within the Norton Basin to proceed with leasing and on the terms and conditions of a lease sale proposal. A decision to offer a nominated area for leasing will depend on a commitment from industry to explore the area leased within a specific time period.

This is the third Call issued for the Norton Basin for this 5-year program. The first two Calls were published in the **Federal Register** on January 22, 2002, and March 25, 2003, respectively. No interest was expressed for either Call; therefore, the process was stopped and deferred to this year. If no interest is expressed in response to this third Call, the MMS will defer the sale for one year and reissue the Call the following year. This process will continue throughout the 5-year program until there is sufficient interest to proceed with the planning steps toward a sale. Only one round of lease issuance in Norton Basin would occur during this 5-year program.

This Call does not indicate a preliminary decision to lease in the area described below. If the MMS decides to proceed with the sale process, the MMS will make the final decision on the specific areas for possible leasing at a later date in the presale process and in compliance with the 5-year program and with applicable laws including all requirements of the National Environmental Policy Act (NEPA) and the OCS Lands Act. The MMS may adjust the dimensions of a nominated area after discussions with the nominating company.

Call for Information and Nominations

1. Authority

This Call is published pursuant to the OCS Lands Act, as amended (43 U.S.C. 1331–1356, [1994]), and the regulations issued thereunder (30 CFR part 256 and 30 CFR part 260); and in accordance with the OCS Oil and Gas Leasing Program 2002 to 2007, approved June 27, 2002.

2. Purpose of Call

The purpose of the Call is to gather preliminary information, to request nomination of specific areas of interest to industry, and to request comments on the terms and conditions of offering these special-interest lands. The Call also serves to initiate public outreach to assist in preparation of the NEPA analysis for this proposal. This proposal is in keeping with Sec. 102(9) of the OCS Lands Act Amendments of 1978, which states as a purpose of the statute, "* * * to insure that the extent of oil and natural gas resources of the OCS is assessed at the earliest practicable time." The objective of the "special-interest" leasing process is to encourage exploration in a frontier OCS area that might contain natural gas for potential use in local communities. The sale would offer for lease both oil and gas.

We seek comments, information, and nominations on oil and gas leasing, exploration, and development and production within the Norton Basin from all interested parties. We also seek comments on the terms, conditions, and economic incentives of a sale in the Norton Basin. We strongly encourage industry and other interested parties to contact the MMS, Alaska OCS Region, Mr. Tom Warren at (907) 271–6691, with questions or to discuss interest in the area. This early planning and consultation step is particularly important to this special-interest lands process. The MMS will base its decision on whether to proceed with the presale process and the terms and conditions of a sale on the nominations and other information received in response to this Call. This process will ensure a decision that considers the concerns of all respondents in future decisions in this leasing process pursuant to the OCSLA and regulations at 30 CFR part 256 and 30 CFR part 260. We encourage commenters to submit comments and suggestions on the "special-interest" leasing process in general.

This Call is being issued in accordance with the OCS Oil and Gas Leasing Program 2002 to 2007, approved June 27, 2002. The program offers one sale in the Norton Basin during the 5-year program. This is the third Call issued for the Norton Basin Program Area. The first two Calls were published in the **Federal Register** on January 22, 2002, and March 25, 2003, respectively. No interest was expressed for either Call. If no interest is expressed in response to this third Call, the MMS will defer the sale for one year and reissue the Call the following year. This process will continue throughout the 5-year program until there is sufficient interest to proceed with the planning steps toward a sale. Only one round of lease issuance in Norton Basin would occur during this 5-year program.

3. Description of Area

The area subject to this Call is located offshore the State of Alaska in the northern Bering Sea, west and south off the coast of the Seward Peninsula. It consists of approximately 4,742 whole and partial blocks (about 25 million acres). It extends offshore from about 3 to approximately 320 miles in water depths from about 25 feet to approximately 650 feet.

A page-size map of the area accompanies this Notice. A large scale Call map showing the boundaries of the area on a block-by-block basis is available without charge from the Public Information Office at the address given below, or by telephone request at (907) 271–6438 or 1–800–764–2627. Copies of Official Protraction Diagrams (OPDs) are also available for $2 each.

Alaska OCS Region, Minerals Management Service, 949 East 36th

Avenue, Room 308, Anchorage, Alaska, 99508–4302, *akwebmaster@mms.gov*.

4. Instructions on Call

The Call for Information Map and indications of interest and/or comments must be submitted to the Regional Supervisor, Leasing and Environment, at the above address.

The Call map delineates the area that is the subject of this Call. Respondents are requested to indicate very specific areas of interest in and comment on the Federal acreage within the boundaries of the Call area that they wish to have included in a proposed sale in the Norton Basin.

If you wish to comment, you may submit your comments by any one of the following methods:

• You may mail comments to the Alaska OCS Region, Minerals Management Service, 949 East 36th Avenue, Room 308, Anchorage, Alaska 99508–4302.

• You may also comment via e-mail to *callforinformation@mms.gov*. Please submit Internet comments as an ASCII file avoiding the use of special characters and any form of encryption. Please also include "Attn: Comments on Call for Information and Nominations for Proposed 2005 Lease Sale in Norton Basin" and your name and return address in your Internet message.

• Finally, you may hand deliver comments to the Alaska OCS Region, Minerals Management Service, 949 East 36th Avenue, Room 308, Anchorage, Alaska 99508–4302.

Our practice is to make comments, including names and addresses of respondents, available for public review during regular business hours. Individual respondents may request that we withhold their address from the rulemaking record, which we will honor to the extent allowable by law. Under certain circumstances we can withhold a respondent's identity, as allowable by law. If you wish us to withhold your name and/or address, you must state this prominently at the beginning of your comment. However, we will not consider anonymous comments. We will make all submissions from organizations or businesses, and from individuals identifying themselves as representatives or officials of organizations or businesses, available for public inspection in their entirety.

A. *Areas of Interest to the Oil and Gas Industry.* Industry must be candid and very specific regarding the areas they nominate if this process is to succeed. The purpose of this process is to identify and offer only small-focused areas where industry has a significant interest in exploration. Nominations covering large-scale areas will not be helpful in defining these areas.

Nominations must be depicted on the Call map by outlining the area(s) of interest along block lines. Nominators are asked to submit a list of whole and partial blocks nominated (by OPD and block number) to facilitate correct interpretation of their nominations on the Call map. Although the identities of those submitting nominations become a matter of public record, the individual nominations are proprietary information. The telephone number and name of a person to contact in the nominator's organization for additional information should be included in the response. This person will be contacted to set up a mutually agreeable time and place for a meeting with the Alaska OCS Regional Office to present their views regarding the company's nominations.

B. *Terms, Conditions, and Economic Incentives Pertaining to Lease Issuance.* We request respondents to comment on the terms, conditions, and economic incentives pertaining to lease issuance for any leases that may be issued as a result of a sale in the Norton Basin. The MMS is aware of the lack of infrastructure and distance from shore to some of the blocks in this area and will consider these factors in designing any incentives. The following are being considered for use in this sale:

—Lease term of 10 years
—Submission of an exploration plan within 8 years of lease issuance
—Economic incentives similar in form to those contained in the Notice of Sale for Beaufort Sea Sale 186 (68 FR 50549). Incentives for Beaufort Sea Sale 186 were:
  —Royalty suspension volumes for oil production (with possible consideration for gas)
  —Reduced rental rates
  —Lower minimum bid requirements

C. *Relation to Coastal Management Plans (CMPs).* We also seek comments on potential conflicts with approved local CMPs that may result from the proposed sale and future OCS oil and gas activities. These comments should identify specific CMP policies of concern, the nature of the conflicts foreseen, and steps that MMS could take to avoid or mitigate the potential conflicts. Comments may be in terms of broad areas or restricted to particular blocks of concern. We request commenters to list block numbers or outline the subject area on the large-scale Call map.

5. Use of Information From Call

Information submitted in response to this Call will be used for several purposes. We will use responses to:

—Determine whether to proceed with a competitive oil and gas lease sale in Norton Basin
—Identify specific areas of interest for oil and/or gas exploration and development
—Identify environmental effects and potential use conflicts
—Assist in the public outreach for the environmental analysis
—Develop possible alternatives to the proposed action
—Develop lease terms and conditions/mitigating measures
—Identify potential conflicts between oil and gas activities and the Alaska CMP

6. Existing Information

An extensive environmental, social, and economic studies program has been underway in the Alaska OCS Region since 1976, including studies in this area. The emphasis has been on geologic mapping, environmental characterization of biologically sensitive habitats, endangered whales and marine mammals, physical oceanography, ocean-circulation modeling, and ecological and socio-cultural effects of oil and gas activities.

The MMS has had one past sale in the Norton Basin area. In March 1983, Sale 57 was held and resulted in 59 leases being issued. There were six exploratory wells drilled, but all have been permanently plugged and abandoned. All 59 leases have been relinquished or expired. The Alaska OCS Region document "Undiscovered Oil and Gas Resources, Alaska Federal Offshore, December 2000 Update" (*http://www.mms.gov/alaska/re/uogr/uogr.pdf*), estimates the undiscovered conventionally recoverable resources at:

Area	Oil and NGL (BBO)			GAS (TCFG)			BOE (BBO)			MPhc
	F95	Mean	F05	F95	Mean	F05	F95	Mean	F05	
NORTON BASIN	0.00	0.05 (NGL)	0.15	0.00	2.71	8.74	0.00	0.53	1.70	0.72

BBO, billions of barrels of oil and natural gas liquids; TCFG, trillions of cubic feet; BOE, total oil and gas in billions of energy-equivalent barrels (5,620 cubic feet of gas=1 energy-equivalent barrel of oil); reported MEAN, resource quantities at the mean in cumulative probability distributions; F95, the resource quantity having a 95-percent probability of being met or exceeded; F05, the resource quantity having a 5-percent probability of being met or exceeded; MPhc, marginal probability for hydrocarbons for basin, *i.e.*, chance for the existence of at least one pool of undiscovered, conventionally recoverable hydrocarbons somewhere in the basin. Resource quantities shown are risked, that is, they are the product of multiplication of conditional resources and Mphc. All liquid resources in Norton basin are natural gas liquids that would only be recovered by natural gas production.

Information on the studies program, completed studies, and a program status report for continuing studies in this area may be obtained from the Chief, Environmental Studies Section, Alaska OCS Region, by telephone request at (907) 271–6577, or by written request at the address stated under Description of Area. A request may also be made via the Alaska OCS Region Web site at *http://www.mms.gov/alaska/ref/pubindex/pubsindex.htm.*

7. Tentative Schedule

If MMS receives specific nominations from industry in response to this Call and decides to proceed with the pre-sale process, the following is a list of tentative milestone dates applicable to a Norton Basin sale in 2005:

	Tentative process milestones for proposed 2005 Norton Basin Sale
Call published/public outreach initiated	January 2004.
Comments due on Call	April 2004.
Decision whether to proceed/Area Identification	May 2004.
NEPA analysis	February 2005.
Consistency Determination/Proposed Notice of Sale	April 2005.
Governor's Comments due	June 2005.
Final Notice of Sale published	August 2005.
Sale	September 2005.

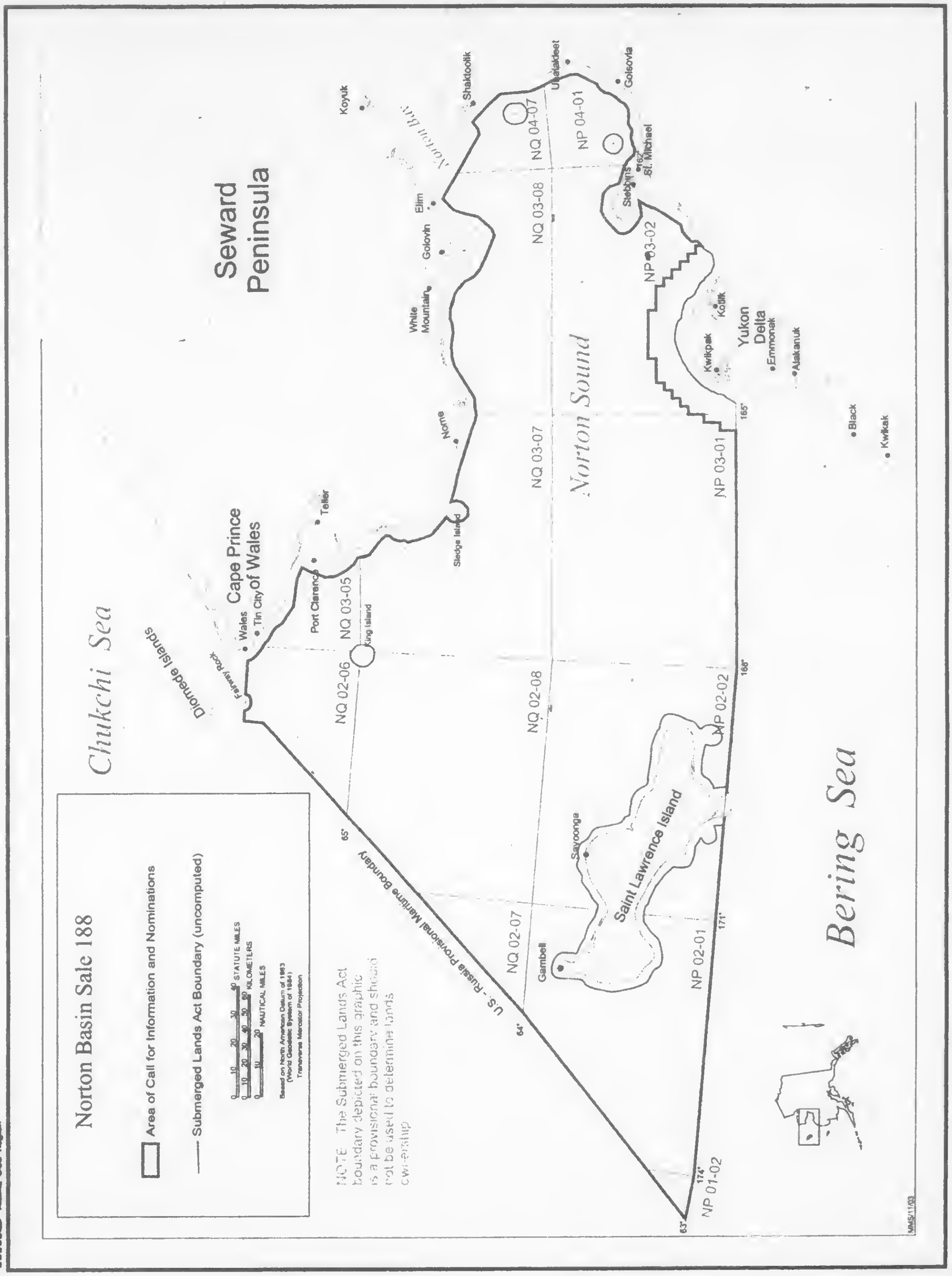
Approved:

Dated: January 20, 2004.

R.M. "Johnnie" Burton,

Director, Minerals Management Service.

BILLING CODE 4310–MR–P


Norton Basin Sale 188
Area of Call for Information and Nominations
Submerged Lands Act Boundary (uncomputed)
STATUTE MILES
KILOMETERS
NAUTICAL MILES
Based on North American Datum of 1983 (World Geodetic System of 1984) Transverse Mercator Projection
NOTE: The Submerged Lands Act boundary depicted on this graphic is a provisional boundary and should not be used to determine lands ownership
U.S. Department of the Interior
Minerals Management Service
Alaska OCS Region
Chukchi Sea
Bering Sea
Norton Sound
Seward Peninsula
Cape Prince of Wales
Diomede Islands
Fairway Rock
Wales
Tin City
Port Clarence
Teller
King Island
Sledge Island
Nome
White Mountain
Golovin
Elim
Koyuk
Shaktoolik
Unalakleet
Golsovia
St. Michael
Stebbins
Kotlik
Yukon Delta
Kwikpak
Emmonak
Alakanuk
Black
Kwikak
Saint Lawrence Island
Savoonga
Gambell
U.S. - Russia Provisional Maritime Boundary
NQ 02-06
NQ 03-05
NQ 02-08
NQ 03-07
NQ 03-08
NQ 04-07
NP 04-01
NP 03-02
NP 03-01
NP 02-02
NQ 02-07
NP 02-01
NP 01-02
65°
64°
63°
174°
171°
168°
165°

[FR Doc. 04–2011 Filed 1–29–04; 8:45 am]
BILLING CODE 4310–MR–C

DEPARTMENT OF LABOR

Office of the Secretary

Submission for OMB Review; Comment Request

January 21, 2004

The Department of Labor (DOL) has submitted the following public information collection requests (ICRs) to the Office of Management and Budget (OMB) for review and approval in accordance with the Paperwork Reduction Act of 1995 (Pub. L. 104–13, 44 U.S.C. chapter 35). A copy of each ICR, with applicable supporting documentation, may be obtained by contacting the Department of Labor. To obtain documentation, contact Ira Mills on 202–693–4122 (this is not a toll-free number) or e-mail: *mills.ira@dol.gov*.

Comments should be sent to Office of Information and Regulatory Affairs, Attn: OMB Desk Officer for the Employee Benefits Security Administration, Office of Management and Budget, Room 10235, Washington, DC 20503, 202–395–7316 (this is not a toll-free number), within 30 days from the date of this publication in the **Federal Register**.

The OMB is particularly interested in comments which:

• Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;

• Evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;

• Enhance the quality, utility, and clarity of the information to be collected; and

• Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, *e.g.*, permitting electronic submission of responses.

Agency: Employee Benefits Security Administration.

Type of Review: Extension of a currently approved collection.

Title: Employee Benefit Plan Claims Procedures under the Employee Retirement Income Security Act of 1974 (ERISA).

OMB Number: 1210–0053.

Affected Public: Individuals or household; Business or other for-profit; Not-for-profit institutions.

Type of Response: Recordkeeping; Third party disclosure.

Frequency: On Occasion.

Number of Respondents: 6,700,000.

Annual Responses: 18,000,000.

Total Burden: 336,200.

Total Annualized Capital/Startup Costs: $0.

Total Annual Costs (operating/ maintaining systems or purchasing services): $90,582,000.

Description: This collection requirements are intended to insure that participants' claims for benefits are given a full and fair review, and that claimants are provided with enough information to understand and request a review of claims decisions. The regulation (29 CFR 2560.503–1), which clarifies the statutory provisions, requires that every claimant who is denied a claim shall be provided with written or electronic notice which contains the specific reasons for denial, a reference to the relevant plan provisions on which the denial is based, a description of steps to be taken if the participant or beneficiary wishes to appeal the denial. The regulation also requires that any adverse decision upon review shall be in writing or by electronic notice and shall include specific reasons for the decision as well as references to relevant plan provisions.

Agency: Employee Benefits Security Administration.

Type of Review: Extension of a currently approved collection.

Title: Prohibited Transaction Exemption 80–83—Securities Purchases for Debt Reduction of Retirement.

OMB Number: 1210–0064.

Affected Public: Business or other for-profit; Individuals or household; Not-for-profit institutions.

Type of Response: Recordkeeping; Third party disclosure.

Frequency: On occasion.

Number of Respondents: 25.

Annual Responses: 25.

Total Burden: 2.

Total Annualized Capital/Startup Costs: $0.

Total Annual Costs (operating/ maintaining systems or purchasing services); $0.

Description: This class exemption allows employee benefit plans to purchase securities to reduce or retire indebtedness to a party in interest. These transactions would otherwise be prohibited under ERISA's prohibited transaction provision. Thus, without the relief provided by the class exemption, a standard type of financial/business transaction between financial service providers and employee benefit plans would be barred. Such a result would not be in the best interest of the plan, its participants and beneficiaries, or the financial services industry.

Agency: Employee Benefits Security Administration.

Type: Extension of a currently approved collection.

Title: Prohibited Transaction Exemption 75–1—Broker-Dealers, Reporting Dealers, Banks Engaging in Securities Transactions.

OMB Number: 1210–0092.

Affected Public: Business or other for-profit; Individuals or household; Not-for-profit institutions.

Type of Response: Recordkeeping; Third party disclosure.

Frequency: On Occasion.

Number of Respondents: 10,600.

Annual Responses: 10,600.

Total Burden: 883.

Total Annualized Capital/Startup Costs: $0.

Total Annual Costs: (operating/ maintaining systems or purchasing services): $0.

Description: The class exemption allows broker-dealers, reporting dealers and banks to engage in securities transactions with employee benefit plans. These transactions would otherwise be prohibited under ERISA's prohibited transaction provisions. Thus, without the relief provided by the class exemption, standard financial/business transactions between financial service providers and employee benefit plans would be barred. Such a result would not be in the best interest of plans, their participants and beneficiaries, or the financial services industry.

Agency: Employee Benefits Security Administration.

Type of Review: Extension of a currently approved collection.

Title: Prohibited Transactions Exemption 88–59—Residential Mortgage Financing Arrangements Involving Employee Benefit Plans.

OMB Number: 1210–0095.

Affected Public: Business or other for-profit; Individuals or household; Not-for-profit institutions.

Type of Response: Recordkeeping; Third party disclosure.

Frequency: On Occasion.

Number of Respondents: 420.

Annual Responses: 2,100

Total Burden: 175.

Total Annualized Capital/Startup Costs: $0.

Total Annual Costs (operating/ maintaining systems or purchasing services): $0.

Description: Prohibited Transaction Class Exemption 88–59 provides an exemption from prohibited transaction provisions of the Employment Retirement Income Security Act of 1974 (ERISA) and from certain taxes imposed by the Internal Revenue Code of 1986.

The exemption permits, under certain conditions, an employee benefit plan to provide mortgage financing to purchasers of residential dwelling units. The mortgage financing may be either by making or participating in loans directly to purchasers or by purchasing mortgage land or participation interests in mortgage loans originated by a third party. Plan investments in real estate mortgage loans typically involved a continuing relationship between the seller of the mortgage loan and the plan for purposes of servicing the mortgage loan investment. This provision of services by the seller creates a party in interest relationship between such servicer and the investing plan. Accordingly, any subsequent purchase of mortgage loans from such existing party in interest service provider results in a prohibited transaction.

By requiring that records pertaining to the exempted transaction be maintained for the duration of any loan made pursuant to Prohibited Transaction Class Exemption 88–59, this ICR insures that the exemption is not abused, the rights of the participants and beneficiaries are protected, and that compliance with the exemption's conditions can be confirmed. The exemption affects participants and beneficiaries of the plans that are involved in such transactions as well as the seller of the mortgage loans.

Ira L. Mills,

Departmental Clearance Officer.

[FR Doc. 04–1952 Filed 1–29–04; 8:45 am]

BILLING CODE 4512–29–M

DEPARTMENT OF LABOR

Employment Standards Administration

Wage and Hour Division

Minimum Wages for Federal and Federally Assisted Construction; General Wage Determination Decisions

General wage determination decisions of the Secretary of Labor are issued in accordance with applicable law and based on the information obtained by the Department of Labor from its study of local wage conditions and data made available from other sources. They specify the basic hourly wage rates and fringe benefits which are determined to be prevailing for the described classes of laborers and mechanics employed on construction projects of a similar character and in the localities specified therein.

The determinations in these decisions of prevailing rates and fringe benefits have been made in accordance with 29 CFR part 1, by authority of the Secretary of Labor pursuant to the provisions of the Davis-Bacon Act of March 3, 1931, as amended (46 Stat. 1494, as amended, 40 U.S.C. 276a) and of other Federal statutes referred to in 29 CFR part 1, Appendix, as well as such additional statutes as may from time to time be enacted containing provisions for the payment of wages determined to be prevailing by the Secretary of Labor in accordance with the Davis-Bacon Act. The prevailing rates and fringe benefits determined in these decisions shall, in accordance with the provisions of the foregoing statutes, constitute the minimum wages payable on Federal and federally assisted construction projects to laborers and mechanics of the specified classes engaged on contract work of the character and in the localities described therein.

Good cause is hereby found for not utilizing notice and public comment procedure thereon prior to the issuance of these determinations as prescribed in 5 U.S.C. 553 and not providing for delay in the effective date as prescribed in that section, because the necessity to issue current construction industry wage determinations frequently and in large volume causes procedures to be impractical and contrary to the public interest.

General wage determination decisions, and modifications and supersedeas decisions thereto, contain no expiration dates and are effective from their date of notice in the **Federal Register**, or on the date written notice is received by the agency, whichever is earlier. These decisions are to be used in accordance with the provisions of 29 CFR parts 1 and 5. Accordingly, the applicable decision, together with any modifications issued, must be made a part of every contract for performance of the described work within the geographic area indicated as required by an appliocable Federal prevailing wage law and 29 CFR Part 5. The wage rates and fringe benefits, notice of which is published herein, and which are contained in the Government Printing Office (GPO) document entitled "General Wage Determinations Issued Under The Davis-Bacon and Related Acts," shall be the minimum paid by contractors and subcontractors to laborers and mechanics.

Any person, organization, or governmental agency having an interest in the rates determined as prevailing is encouraged to submit wage rate and fringe benefit information for consideration by the Department.

Further information and self-explanatory forms for the purpose of submitting this data may be obtained by writing to the U.S. Department of Labor, Employment Standards Administration, Wage and Hour Division, Division of Wage Determinations, 200 Constitution Avenue, NW., Room S–3014, Washington, DC 20210.

Modification to General Wage Determination Decisions

The number of the decisions listed to the Government Printing Office document entitled "General Wage Determinations Issued Under the Davis-Bacon and Related Acts" being modified are listed by Volume and State. Dates of publication in the **Federal Register** are in parentheses following the decisions being modified.

Volume I

None

Volume II

Maryland
- MD030056 (Jun. 13, 2003)
- MD030057 (Jun. 13, 2003)

Pennsylvania
- PA030013 (Jun. 13, 2003)
- PA030033 (Jun. 13, 2003)

Volume III

Kentucky
- KY030029 (Jun. 13, 2003)

Mississippi
- MS030003 (Jun. 13, 2003)

North Carolina
- NC030055 (Jun. 13, 2003)

Volume IV

None

Volume V

Arkansas
- AR030008 (Jun. 13, 2003)
- AR030023 (Jun. 13, 2003)
- AR030027 (Jun. 13, 2003)

Kansas
- KS030006 (Jun. 13, 2003)
- KS030009 (Jun. 13, 2003)
- KS030012 (Jun. 13, 2003)
- KS030019 (Jun. 13, 2003)
- KS030025 (Jun. 13, 2003)
- KS030026 (Jun. 13, 2003)
- KS030063 (Jun. 13, 2003)

Louisiana
- LA030009 (Jun. 13, 2003)
- LA030014 (Jun. 13, 2003)
- LA030045 (Jun. 13, 2003)
- LA030054 (Jun. 13, 2003)

Oklahoma
- OK030017 (Jun. 13, 2003)
- OK030018 (Jun. 13, 2003)
- OK030030 (Jun. 13, 2003)

Volume VI

Washington
- WA030009 (Jun. 13, 2003)

Volume VII

California
CA030001 (Jun. 13, 2003)
CA030002 (Jun. 13, 2003)
CA030019 (Jun. 13, 2003)
CA030025 (Jun. 13, 2003)
CA030031 (Jun. 13, 2003)
CA030033 (Jun. 13, 2003)
CA030035 (Jun. 13, 2003)
CA030036 (Jun. 13, 2003)
CA030037 (Jun. 13, 2003)

General Wage Determination Publication

General wage determinations issued under the Davis-Bacon and related Acts, including those noted above, may be found in the Government Printing Office (GPO) document entitled "General Wage determinations Issued Under the Davis-Bacon And Related Acts". This publication is available at each of the 50 Regional Government Depository Libraries and many of the 1,400 Government Depository Libraries across the country.

General wage determinations issued under the Davis-Bacon and related Acts are available electronically at no cost on the Government Printing Office site at *www.access.gpo.gov/davisbacon*. They are also available electronically by subscription to the Davis-Bacon Online Service (*http://davisbacon.fedworld.gov*) of the National Technical Information Service (NTIS) of the U.S. Department of Commerce at 1–800–363–2068. This subscription offers value-added features such as electronic delivery of modified wage decisions directly to the user's desktop, the ability to access prior wage decisions issued during the year, extensive Help desk Support, etc.

Hard-copy subscriptions may be purchased from: Superintendent of Documents, U.S. Government Printing Office, Washington, DC 20402, (202) 512–1800.

When ordering hard-copy subscription(s), be sure to specify the State(s) of interest, since subscriptions may be ordered for any or all of the six separate Volumes, arranged by State. Subscriptions include an annual edition (issued in January or February) which includes all current general wage determinations for the States covered by each volume. Throughout the remainder of the year, regular weekly updates will be distributed to subscribers.

Signed at Washington, DC this 22nd day of January 2004.

Carl J. Poleskey,

Chief, Branch of Construction Wage Determinations.

[FR Doc. 04–1785 Filed 1–29–04; 8:45 am]

BILLING CODE 4510–27–M

NATIONAL LABOR RELATIONS BOARD

Sunshine Act Meeting

AGENCY: National Labor Relations Board.

TIME AND DATE: 10 a.m., Tuesday, January 27, 2004.

PLACE: Board Conference Room, Eleventh Floor, 1099 Fourteenth St., NW., Washington, DC 20570.

STATUS: Closed to public observation pursuant to 5 U.S.C. Section 552b(c)(2) (internal personnel rules and practices).

MATTERS TO BE CONSIDERED: Internal Matters and Collective Bargaining Matters.

FOR FURTHER INFORMATION CONTACT: Lester A. Heltzer, Executive Secretary, Washington, DC 20570, Telephone: (202) 273–1067.

Dated, Washington, DC., January 29, 2004.

By direction of the Board.

Lester A. Heltzer,

Executive Secretary, National Labor Relations Board.

[FR Doc. 04–2080 Filed 1–28–04; 3:31 pm]

BILLING CODE 7545–01–M

NUCLEAR REGULATORY COMMISSION

[Docket No. 72–39]

Connecticut Yankee Atomic Power Company, Haddam Neck Plant; Environmental Assessment and Finding of No Significant Impact

The U.S. Nuclear Regulatory Commission (NRC or Commission) is considering issuance of an exemption to Connecticut Yankee Atomic Power Company (CYAPCO or licensee), pursuant to 10 CFR 72.7, from the specific provisions of 10 CFR 72,212(a)(2), 72.212(b)(2)(i)(A), 72.212(b)(7), and 72.214. The licensee is using the NAC Multi-Purpose Cansiser System (NAC–MPC), Certificate of Compliance (CoC) No. 1025, to store spent fuel under a general license in an independent spent fuel storage installation (ISFSI) associated with the operation of the Haddam Neck Plant (HNP), located in Middlesex County, Connecticut. The requested exemption would allow CYAPCO to use vacuum drying enhancements prior to completion of the proposed NAC–MPC CoC amendment rulemaking.

Environmental Assessment

Identification of the Proposed Action

The proposed action would exempt CYAPCO from the requirements of 10 CFR 72.212(a)(2), 72.212(b)(2)(i)(A), 72.212(b)(7), and 72.214 for using the NAC–MPC at HNP. These regulations specifically require compliance with the conditions set forth in the CoC for each dry spent fuel storage cask used by an ISFSI general licensee. The NAC–MPC CoC provides limiting conditions for operation (LCO) requirements in Appendix A, Technical Specifications, and Appendix B, Approved Content and Design Features. The proposed action would allow CYAPCO to deviate from (1) the vacuum drying, water cooling, and forced air cooling time limits in LCO 3.1.1 of Appendix A, (2) the canister in transfer cask time limits in LCO 3.1.4 of Appendix A, (3) the fuel cooldown requirements in LCO 3.1.7, (4) the canister removal from concrete cask requirements of LCO 3.1.8, (5) the surface contamination removal time limits in LCO 3.2.1, and (6) the allowable contents fuel assembly limits in Table B2–3 of Appendix B. The proposed action would implement the vacuum drying enhancements requested by NAC International in the NAC–MPC CoC amendment request currently under staff review.

The proposed action is in accordance with the licensee's application dated August 28, 2003.

The Need for the Proposed Action

The proposed action is needed because CYAPCO plans to initiate the transfer of the HNP spent fuel pool contents to the independent spent fuel storage installation in December 2003. The fuel transfer campaign is scheduled to begin immediately following the transfer of Greater than Class C (GTCC) material stored under CYAPCO's 10 CFR Part 50 license. The licensee has stated that the exemption is requested to significantly reduce the time required for vacuum drying and to significantly improve loading operations. Additionally, eliminating unnecessary cooldown cycles and cask handling activities reduces the potential dose to workers consistent with good ALARA practices. Prolonged loading operations are not desired because it would result in delays in the schedule, delays in decommisioning activities, and associated resource impacts due to the delays. The proposed action is necessary because the 10 CFR 72.214 rulemaking to implement the NAC–MPC CoC amendment is not projected for completion until Spring 2004, which will not support the HNP fuel transfer and dry cask storage loading schedule.

Environmental Impacts of the Proposed Action

The NRC has completed its evaluation of the proposed action and concludes that there is no significant environmental impact if the exemption is granted. The staff reviewed the analysis provided in the NAC–MPC amendment application addressing vacuum drying enhancements. The safety evaluation performed by the staff concludes that the NRC has reasonable assurance that the vacuum drying enhancements have no impact on off-site doses. The potential environmental impact of using the NAC–MPC System was initially presented in the Environmental Assessment (EA) for the Final Rule to add the NAC–MPC System to the list of approved spent fuel storage casks in 10 CFR 72.214 (64 FR 12444, dated March 9, 2000), as revised in Amendment No. 1 (66 FR 58956, dated November 20, 2001), in Amendment No. 2 (67 FR 11566, dated March 15, 2002), and in Amendment No. 3 (68 FR 55304, dated September 25, 2003). The vacuum drying enhancements do not increase the probability or consequences of accidents, no changes are being made in the types of any effluents that may be released offsite, and there is no significant increase in occupational or public radiation exposure. Therefore, there are no significant radiological environmental impacts associated with the proposed action.

With regard to potential nonradiological impacts, the proposed action does not have a potential to affect any historic sites. It does not affect nonradiological plant effluents and has no other environmental impact. Therefore, there are no significant nonradiological environmental impacts associated with the proposed action.

Accordingly, the NRC concludes that there are no significant environmental impacts associated with the proposed action.

Alternatives to the Proposed Action

Since there is no significant environmental impact associated with the proposed action, alternatives with equal or greater environmental impact were not evaluated. As an alternative to the proposed action, the staff considered denial of the proposed action. Denial of the exemption would result in no change in current environmental impact, but would result in a potential dose increase to workers involved in cooldown cycle cask handling activities.

Agencies and Persons Consulted

On December 31, 2003, the staff consulted with Mr. Michael Firsick of the Connecticut Department of Environmental Protection, regarding the environmental impact of the proposed action. He had no comments. The NRC staff has determined that a consultation under Section 7 of the Endangered Species Act is not required because the proposed action will not affect listed species or critical habitat. The NRC staff has also determined that the proposed action is not a type of activity having the potential to cause effects on historic properties. Therefore, no further consultation is required under Section 106 of the National Historic Preservation Act.

Finding of No Significant Impact

The environmental impacts of the proposed action have been reviewed in accordance with the requirements set forth in 10 CFR Part 51. Based on the foregoing Environmental Assessment, the Commission finds that the proposed action of granting an exemption from 10 CFR 72.212(a)(2), 72.212(b)(2) (i) (A), 72.212(b)(7), and 72.214 allowing CYAPCO to deviate from the current vacuum drying time limits and incorporate other vacuum drying enhancements, will not significantly impact the quality of the human environment. Accordingly, the Commission has determined not to prepare an environmental impact statement for the proposed action.

For further details with respect to this exemption request, see the CYAPCO's letter dated August 28, 2003. The request for exemption was docketed under 10 CFR Part 72, Docket 72–39. The NRC maintains an Agencywide Documents Access and Management System (ADAMS), which provides text and image files of NRC's public documents. These documents may be accessed through the NRC's Public Electronic Reading Room on the Internet at *http://www.nrc.gov/reading-rm/adams.html*. If you do not have access to ADAMS or if there are problems in accessing the documents located in ADAMS, contact the NRC Public Document Room (PDR) Reference staff at 1–800–397–4209, or 301–415–4737, or by e-mail at *pdr@nrc.gov*.

Dated at Rockville, Maryland, this 22nd day of January, 2004.

For the Nuclear Regulatory Commission.

L. Raynard Wharton,

Project Manager, Spent Fuel Project Office, Office of Nuclear Material Safety and Safeguards.

[FR Doc. 04–1943 Filed 1–29–04; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

[Docket 72–30]

Maine Yankee Atomic Power Company Independent Spent Fuel Storage Installation Issuance of Environmental Assessment and Finding of No Significant Impact for a Proposed Exemption

The U.S. Nuclear Regulatory Commission (NRC or Commission) is considering issuance of an exemption to Maine Yankee Atomic Power Company (MYAPC or licensee), pursuant to 10 CFR 72.7, from specific provisions of 10 CFR 72.212(a)(2), 72.212(b)(2)(i), 72.212(b)(7), and 72.214. The licensee is using the NAC–UMS Storage System to store spent nuclear fuel from the decommissioning reactor at an Independent Spent Fuel Storage Installation (ISFSI). The requested exemption would allow MYAPC to deviate from requirements of the NAC–UMS Certificate of Compliance No. 1015 (CoC or Certificate), Amendment 2, Appendix B, Section B 3.4.2.6. Specifically, the exemption would relieve MYAPC from the requirement to maintain a coefficient of friction between the vertical concrete cask and ISFSI pad surface of at least 0.5.

Environmental Assessment (EA)

Identification of Proposed Action

By letter dated October 2, 2003, as supplemented on October 21, 2003, MYAPC requested an exemption from the requirements of 10 CFR 72.212(a), 72.212(b)(2)(i), 72.212(b)(7), and 10 CFR 72.214 to deviate from the requirements in CoC No. 1015, Amendment 2, Appendix B, Section B 3.4.2.6. MYAPC is storing spent nuclear fuel under the general licensing provisions of 10 CFR part 72 in the NAC–UMS Storage System at an ISFSI located at the Maine Yankee Atomic Power Station in Wiscasset, Maine. The licensee is loading additional spent fuel into storage at the ISFSI.

The current requirements in CoC No. 1015, Amendment 2, Appendix B, state that physical testing shall be conducted to demonstrate that the coefficient of friction between the vertical concrete cask and ISFSI pad surface is at least 0.5.

By exempting MYAPC from specific provisions of 10 CFR 72.212(a)(2), 72.212(b)(2)(i), 72.212(b)(7), and 10 CFR 72.214 for this request, MYAPC will not be required to maintain a coefficient of friction between the vertical concrete cask and ISFSI pad surface of at least 0.5.

The proposed action before the Commission is whether to grant this exemption under the provisions of 10 CFR 72.7. The NRC staff has reviewed the exemption request and determined that not maintaining a coefficient of friction between the vertical concrete cask and the ISFSI pad surface of at least 0.5, is consistent with the safety analyses previously reviewed for the NAC–UMS system, and would have no impact on the design basis and would not be inimical to public health and safety.

Need for the Proposed Action

During the 2002–2003 winter, MYAPC discovered a condition in which the surface area between the vertical concrete casks and the ISFSI pad had a significant covering of ice (approximately 80–95 percent of the surface). This winter icing condition may result in a reduced coefficient of friction that does not meet the requirements of CoC No. 1015, Amendment 2, Section B 3.4.2.6, for a coefficient of friction of at least 0.5 between the vertical concrete casks and the ISFSI pad surface. The icing condition was unanticipated and therefore not explicitly addressed in the cask licensing basis. The presence of ice causes a loss of contact between the vertical concrete casks and the ISFSI pad and leads to an indeterminate coefficient of friction. Since the icing condition renders previous test results insufficient to demonstrate a coefficient of friction greater than 0.5, MYAPC would not be in compliance with the CoC during these icing conditions.

Granting the requested exemption will allow MYAPC to regain compliance with CoC No. 1015, Amendment 2, in a timely manner. Section B 3.4.2.6 is a requirement specific to MYAPC and applicable to no other licensees.

Environmental Impacts of the Proposed Action

The licensee requested the exemption from maintaining a coefficient of friction between the vertical concrete cask and the ISFSI pad surface of at least 0.5 as specified in CoC No. 1015, Amendment 2. The NRC staff performed a safety evaluation of the proposed exemption. Staff reviewed the analysis provided by MYAPC in the exemption request for winter icing conditions which may result in a reduced coefficient of friction between the vertical concrete cask and the ISFSI pad surface, and limited vertical concrete cask sliding during a design earthquake. Staff judged that the design earthquake will not cause large sliding of the NAC–UMS vertical concrete cask on the ISFSI pad surfaces. In the unlikely event of vertical concrete cask impacts, staff evaluated the magnitude of the impact load between two colliding casks and determined the impact load would be far less severe than that encountered in a tip-over accident for which the NAC–UMS system has been demonstrated structurally adequate. The staff concludes that the NRC has reasonable assurance that the proposed exemption has no impact on off-site doses, and is acceptable.

Therefore, the environmental impact of not maintaining a coefficient of friction between the vertical concrete cask and the ISFSI pad surface of at least 0.5, is no greater than the environmental impact already assessed in the initial rulemaking for the NAC–UMS storage system (65 FR 62581, dated October 19, 2000).

The proposed action will not increase the probability or consequences of the analyzed accidents, no changes are being made to the types of effluents that may be released offsite, and there is no increase in occupational or public radiation exposure. Therefore, there are no significant radiological environmental impacts associated with the proposed action. Therefore, the staff has determined that there is no reduction in the ability of the NAC–UMS system to perform its safety function, nor significant environmental impacts, as a result of not maintaining a coefficient of friction between the vertical concrete cask and the ISFSI pad surface of at least 0.5.

Alternative to the Proposed Action

Since there is no significant environment impact associated with the proposed action, alternatives with equal or greater environmental impact are not evaluated. The alternative to the proposed action would be to deny approval of the exemption. Denial of the exemption request will have the same environmental impact.

Agencies and Persons Consulted

This exemption request was discussed with Mr. Charles Pray, State Nuclear Safety Advisor for the State of Maine, on January 6, 2004, and he stated that the State had no comments on the technical aspects of the exemption. The NRC staff has determined that a consultation under Section 7 of the Endangered Species Act is not required because the proposed action will not affect listed species or critical habitat. The NRC staff has also determined that the proposed action is not a type of activity having the potential to cause effects on historic properties. Therefore, no further consultation is required under Section 106 of the National Historic Preservation Act.

Finding of No Significant Impact

The environmental impacts of the proposed action have been reviewed in accordance with the requirements set forth in 10 CFR Part 51. Based upon the foregoing EA, the Commission finds that the proposed action of granting the exemption from specific provisions of 10 CFR 72.212(a), 72.212(b)(2)(i), 72.212 (b)(7), and 10 CFR 72.214, and not requiring MYAPC to maintain a coefficient of friction between the concrete cask and ISFSI pad surface of at least 0.5, will not significantly impact the quality of the human environment. Accordingly, the Commission has determined that an environmental impact statement for the proposed exemption is not warranted.

The request for exemption was docketed under 10 CFR part 72, Docket 72–30. For further details with respect to this action, see the exemption request dated October 2, 2003, as supplemented. The NRC maintains an Agencywide Documents Access and Management System (ADAMS), which provides text and image files of NRC's public documents. These documents may be accessed through the NRC's Public Electronic Reading Room on the Internet at *http://www.nrc.gov/reading-rm/adams.html*. If you do not have access to ADAMS or if there are problems in accessing the documents located in ADAMS, contact the NRC Public Document Room Reference staff at 1–800–397–4209, 301–415–4737, or by e-mail to *pdr@nrc.gov*.

Dated at Rockville, Maryland, this 23rd day of January, 2004.

For the Nuclear Regulatory Commission.

Stephen C. O'Connor, Sr.,

Project Manager, Spent Fuel Project Office, Office of Nuclear Material Safety and Safeguards.

[FR Doc. 04–1944 Filed 1–29–04; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

[Docket No. 70–7003]

Notice of Availability of Environmental Assessment and Finding of No Significant Impact for License Application for USEC, Inc., Bethesda, MD; Correction

AGENCY: Nuclear Regulatory Commission.

ACTION: Notice of availability of environmental assessment and finding of no significant impact for license application; correction.

SUMMARY: The U.S. Nuclear Regulatory Commission published a Finding of No Significant Impact (FONSI) in the **Federal Register** on January 27, 2004 (69 FR 3956), concerning the United States Enrichment Corporation Inc.'s (USEC Inc.'s) license application for its American Centrifuge Lead Cascade Facility (Lead Cascade) in Piketon, Ohio. The FONSI contained an incorrect number.

FOR FURTHER INFORMATION CONTACT: Yawar Faraz, NMSS/FCSS (301) 415–8113.

Correction

In the **Federal Register** of January 27, 2004, in volume 69, number 17, on page 3956, correct the 0.0001% value to 1%. The corrected sentence, which is the third sentence of the third full paragraph in the third column, should read as follows:

"For example, NRC staff finds that public exposure to radiation from the proposed action will be less than 1% of the limits in 10 CFR part 20."

Dated in Rockville, Maryland this 27th day of January, 2004.

For the Nuclear Regulatory Commission.

Michael T. Lesar,

Chief, Rules Review and Directives Branch, Division of Administrative Services, Office of Administration.

[FR Doc. 04–2018 Filed 1–29–04; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

Advisory Committee on Nuclear Waste, Meeting on Planning and Procedures; Notice of Meeting

The ACNW will hold a planning and procedures meeting on February 26, 2004, Room T–2B1, 11545 Rockville Pike, Rockville, Maryland.

The entire meeting will be open to public attendance, with the exception of a portion that may be closed pursuant to 5 U.S.C. 552b(c)(2) and (6) to discuss organizational and personnel matters that relate solely to internal personnel rules and practices of ACNW, and information the release of which would constitute a clearly unwarranted invasion of personal privacy.

The agenda for the subject meeting shall be as follows:

Thursday, February 26, 2004—8 a.m.–11 a.m.

The Committee will discuss proposed ACNW activities and related matters. The purpose of this meeting is to 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. Howard J. Larson (telephone: 301/415–6805) between 7:30 a.m. and 4:15 p.m. (e.t.) five days prior to the meeting, if possible, so that appropriate arrangements can be made. Electronic recordings will be permitted only during those portions of the meeting that are open to the public.

Further information regarding this meeting can be obtained by contacting the Designated Federal Official between 7:30 a.m. and 4:15 p.m. (e.t.). 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 in the agenda.

Dated: January 23, 2004.

Sher Bahadur,

Associate Director for Technical Support, ACRS/ACNW.

[FR Doc. 04–2015 Filed 1–29–04; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

Advisory Committee on Reactor Safeguards, Meeting of the ACRS Subcommittee on Reliability and Probabilistic Risk Assessment; Notice of Meeting

The ACRS Subcommittee on Reliability and Probabilistic Risk Assessment will hold a meeting on February 19, 2004, Room T–2B3, 11545 Rockville Pike, Rockville, Maryland.

The entire meeting will be open to public attendance.

The agenda for the subject meeting shall be as follows:

Thursday, February 19, 2004—8:30 a.m. Until the Conclusion of Business

The purpose of this meeting is to review the ongoing resolution of public comments on the proposed 10 CFR 50.69, "Risk-Informed Categorization and Treatment of Structures, Systems, and Components," and the staff's draft Regulatory Guide endorsing Revision D of NEI 00–04, "10 CFR 50.69 Structures, Systems, and Components Categorization Guideline." The Subcommittee will hear presentations by and hold discussions with representatives of the NRC staff and NEI regarding this matter. 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 R. Snodderly (telephone: 301–415–6927) five days prior to the meeting, if possible, so that appropriate arrangements can be made. Electronic recordings will be permitted during the meeting.

Further information regarding this meeting can be obtained by contacting the Designated Federal Official between 7:30 a.m. and 4:15 p.m. (e.t.). 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: January 23, 2004.

Sher Bahadur,

Associate Director for Technical Support, ACRS/ACNW.

[FR Doc. 04–2016 Filed 1–29–04; 8:45 am]

BILLING CODE 7590–01–P

SECURITIES AND EXCHANGE COMMISSION

Submission for OMB Review; Comment Request

Upon Written Request, Copies Available From: Securities and Exchange Commission, Office of Filings and Information Services, Washington, DC 20549.

Extension:

Rule 17Ad–11; SEC File No. 270–261; OMB Control No. 3235–0274.

Notice is hereby given that pursuant to the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*), the Securities and Exchange Commission ("Commission") has submitted to the Office of Management and Budget a request for extension of the previously approved collection of information discussed below.

Rule 17Ad–11: Reports Regarding Aged Record Differences, Buy-Ins, and Failure To Post Certificate Detail to Master Securityholder Files

Rule 17Ad–11 requires all registered transfer agents to report to issuers and the appropriate regulatory agency in the event that aged record differences exceed certain dollar value thresholds. An aged record difference occurs when an issuer's records do not agree with those of securityowners as indicated, for instance, on certificates presented to the transfer agent for purchase, redemption or transfer. In addition, the rule requires transfer agents to report to the appropriate regulatory agency in the event of a failure to post certificate detail to the master securityholder file within 5 business days of the time required by Rule 17Ad–10. Also, transfer agents must maintain a copy of each report prepared under Rule 17Ad–11 for a period of three years following the date of the report. This recordkeeping requirements assist the Commission and other regulatory agencies with monitoring transfer agents and ensuring compliance with the rule.

Because the information required by Rule 17Ad–11 is already available to transfer agents, any collection burden for small transfer agents is minimal. The staff estimates that the average number of hours necessary to comply with Rule 17Ad–11 is one hour annually. Based upon past submissions, the total burden is 150 hours annually for transfer agents.

The retention period for the recordkeeping requirement under Rule 17Ad–11 is three years following the date of a report prepared pursuant to the rule. The recordkeeping requirement under Rule 17Ad–11 is mandatory to assist the Commission and other regulatory agencies with monitoring transfer agents and ensuring compliance with the rule. This rule does not involve the collection of confidential information. Please note that 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 control number.

General comments regarding the estimated burden hours should be directed to the following persons: (i) Desk Officer for the Securities and Exchange Commission, Office of Information and Regulatory Affairs, Office of Management and Budget, Room 10102, New Executive Office Building, Washington, DC 20503; and (ii) Kenneth A. Fogash, Acting Associate Executive Director/CIO, Office of Information Technology, Securities and Exchange Commission, 450 Fifth Street, NW., Washington, DC 20549. Comments must be submitted to OMB within 30 days of this notice.

Dated: January 7, 2004.

Jill M. Peterson,

Assistant Secretary.

[FR Doc. 04–1957 Filed 1–29–04; 8:45 am]

BILLING CODE 8010–01–P

SECURITIES AND EXCHANGE COMMISSION

Submission for OMB Review; Comment Request

Upon Written Request, Copies Available From: Securities and Exchange Commission, Office of Filings and Information Services, Washington, DC 20549.

Extension:

Rule 17Ad–13; SEC File No. 270–263; OMB Control No. 3235–0275.

Notice is hereby given that pursuant to the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*), the Securities and Exchange Commission ("Commission") has submitted to the Office of Management and Budget a request for extension of the previously approved collection of information discussed below.

• Rule 17Ad–13 Annual Study and Evaluation of Internal Accounting Control.

Rule 17Ad–13 requires approximately 200 registered transfer agents to obtain an annual report on the adequacy of internal accounting controls. In addition, transfer agents must maintain copies of any reports prepared pursuant to Rule 17Ad–13 plus any documents prepared to notify the Commission and appropriate regulatory agencies in the event that the transfer agent is required to take any corrective action. These recordkeeping requirements assist the Commission and other regulatory agencies with monitoring transfer agents and ensuring compliance with the rule. Small transfer agents are exempt from Rule 17Ad–13.

The staff estimates that the average number of hours necessary for each transfer agent to comply with Rule 17Ad–13 is one hundred seventy-five hours annually. The total burden is 35,000 hours annually for transfer agents, based upon past submissions.

The retention period for the recordkeeping requirement under Rule 17Ad–13 is three years following the date of a report prepared pursuant to the rule. The recordkeeping requirement under Rule 17Ad–13 is mandatory to assist the Commission and other regulatory agencies with monitoring transfer agents and ensuring compliance with the rule. This rule does not involve the collection of confidential information. Please note that 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 control number.

General comments regarding the estimated burden hours should be directed to the following persons: (i) Desk Officer for the Securities and Exchange Commission, Office of Information and Regulatory Affairs, Office of Management and Budget, Room 10102, New Executive Office Building, Washington, DC 20503; and (ii) Kenneth A. Fogash, Acting Associate Executive Director/CIO, Office of Information Technology, Securities and Exchange Commission, 450 Fifth Street, NW., Washington, DC 20549. Comments must be submitted to OMB within 30 days of this notice.

Dated: January 7, 2004.

Jill M. Peterson,

Assistant Secretary.

[FR Doc. 04–1958 Filed 1–29–04; 8:45 am]

BILLING CODE 8010–01–P

SECURITIES AND EXCHANGE COMMISSION

Proposed Collection; Comment Request

Upon Written Request, Copies Available From: Securities and Exchange Commission, Office of Filings and Information Services, Washington, DC 20549.

Extension:

Rule 24; SEC File No. 270–129; OMB Control No. 3235–0126.

Notice is hereby given that, pursuant to the Paperwork Reduction Act of 1995 (44 U.S.C. 3501, *et seq.*), the Securities and Exchange Commission ("Commission") is soliciting comments on the collection of information summarized below. The Commission plans to submit to the Office of Management and Budget ("OMB") a request for an extension of the previously OMB approved rule 24 (17 C.F.R. 250.24) under the Public Utility Holding Company Act of 1935 (15 U.S.C. 79a *et seq.*) ("Act").

Rule 24 under the Act requires the filing with the Commission of certain information indicating that an authorized transaction has been carried out in accordance with the terms and conditions of the Commission order authorizing the transaction. The Commission needs the information under rule 24 to ensure that the terms and conditions of its orders are being complied with, and the Commission uses the information to ensure appropriate compliance with the Act. The respondents are comprised of two groups of entities: (a) Registered holding companies under the Act and their direct and indirect subsidiaries and affiliates; and (b) holding companies exempt from the provisions of the Act by rule or order from all provisions of the Act, except section 9(a)(2). It is estimated that the total number of respondents is 140. The Commission estimates that the total annual reporting burden under rule 24 is 1005 hours (*e.g.*, 335 filings x 3 hours = 1005 burden hours).

These estimates of average burden hours are made solely for the purposes of the Paperwork Reduction Act and are not derived from a comprehensive or even a representative survey or study of the costs of SEC rules and forms. There is no requirement to keep the information in the forms confidential because it is public information.

Written comments are invited on (a) whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will 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 collected; and (d) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology. Consideration will be given to comments and suggestions submitted in writing within 60 days of this publication.

Please direct your written comments to R. Corey Booth, Director/Chief Information Officer, Office of Information Technology, Securities and Exchange Commission, 450 5th Street, NW., Washington, DC 20549.

Dated: January 21, 2004.

Jill M. Peterson,

Assistant Secretary.

[FR Doc. 04–1959 Filed 1–29–04; 8:45 am]

BILLING CODE 8010–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–49125; File No. SR–FICC–2003–01]

Self-Regulatory Organizations; Fixed Income Clearing Corporation; Notice of Filing of a Proposed Rule Change Relating to the Implementation of Fines

January 26, 2004.

Pursuant to section 19(b)(1) of the Securities Exchange Act of 1934 ("Act"),[1] notice is hereby given that on January 3, 2003, the Fixed Income Clearing Corporation ("FICC") filed with the Securities and Exchange Commission ("Commission") and on January 8, 2003, and June 8, 2003, amended the proposed rule change as described in items I, II, and III below, which items have been prepared primarily by FICC. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

[1] 15 U.S.C. 78s(b)(1).

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The proposed rule change implements fines for the failure to timely submit required financial reports and to meet certain additional reporting requirements. The proposed rule change also eliminates a provision in FICC's rules allowing foreign members to prepare their financial statements in accordance with accounting standards other than U.S. Generally Accepted Accounting Principles ("GAAP").

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, FICC included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in item IV below. FICC has prepared summaries, set forth in sections (A), (B), and (C) below, of the most significant aspects of such statements.[2]

(A) Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

Pursuant to section 5 of Rule 2 of the rules of the Government Securities Division of FICC and section 10 of Rule 2 of Article III of the rules of the Mortgage Backed Securities Division of FICC and in furtherance of FICC's obligation to minimize risk to all members, FICC requires that on a periodic basis members submit to FICC financial reports detailing certain information about their financial status.[3] These reports submitted by members are crucial to FICC surveillance procedures because they allow FICC credit risk personnel to review and monitor the financial condition of members. While the majority of FICC members satisfy their reporting obligations in a timely manner, from time to time certain FICC members fail to submit their reports to FICC on time. The lack of timely submissions adversely affects FICC's financial surveillance processes and ultimately creates risk for FICC and its members. To remedy this situation, FICC is proposing the implementation of a fine schedule in order to promote improved compliance with reporting timeframes.

[2] The Commission has modified parts of these statements.

[3] These reports include monthly FOCUS and FOGS reports, quarterly CALL reports, annual audited financial statements, and other periodic financial data as outlined in FICC's rules.

Historically, GSCC and MBSCC, FICC's predecessors, have instituted fines and late fees in order to enforce various deadlines, rules, and procedures. Since February 2002, GSCC has been charging members fees for failure to timely provide repo collateral substitution notifications. In July 2001, GSCC began imposing fees on those members who submit trade data on a non-interactive basis. In addition, since 1998 GSCC has had the authority to impose fines in order to promote greater compliance with its funds settlement debit and clearing fund deposit deficiency call deadlines. MBSCC likewise charges members additional fees for late payment of settlement balance order market differential payments and cash adjustment payments.

As with other fines that are currently in place, members will have the ability to contest the proposed fines through the process set forth in Rule 37 of the Government Securities Division's rules and Rule 7 of Article V of the Mortgage Backed Securities Division's rules.

FICC is also proposing to amend the rules of both the Government Securities Division and the Mortgage Backed Securities Division to require members to submit to FICC, concurrently with their submission to the applicable regulator, copies of such filings as determined by FICC from time to time, which members are required to file pursuant to the Sarbanes-Oxley Act of 2002 (and any amendments thereunder). In addition, FICC is proposing to amend the rules of the Government Securities Division to require members to submit to FICC, concurrently with their submission to the applicable regulator, all reports or other notifications required to be filed when their capital levels fall below required minimums.[4]

[4] Both divisions require broker-dealer participants to submit copies of supplemental reports filed pursuant to Rule 17a–11 under the Act to FICC concurrently with their submission to the Commission. Rule 17a–11 requires registered broker-dealers to notify the Commission of a decline in net capital below minimum Commission requirements. However, participants (including

Continued

Section 5 of Rule 2 allows non-U.S. members to submit, among other things, to FICC audited financial statements and other financial information that has been prepared in accordance with U.S. GAAP, International Accounting Standards, or United Kingdom GAAP. In the filing, FICC is proposing to amend this section to require the financial information submitted to it to be prepared only in accordance with U.S. GAAP.

FICC believes the proposed rule change is consistent with the requirements of the Act and the rules and regulations thereunder because it allows FICC to monitor the financial condition of members more completely and on a timely basis, thereby limiting the risk to FICC and its members.

(B) Self-Regulatory Organization's Statement on Burden on Competition

FICC does not believe that the proposed rule change would have an impact on or impose a burden on competition.

(C) Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received from Members, Participants, or Others

Written comments relating to the proposed rule change have not yet been solicited nor received. FICC will notify the Commission of any written comments received by FICC.

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 ninety days of such date if it finds such longer period to be appropriate and publishes its reasons for so finding or (ii) as to which the self-regulatory organization consents, the Commission will:

(a) By order approve the proposed rule change or

(b) Institute proceedings to determine whether the proposed rule change should be disapproved.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Persons making written submissions should file six copies thereof with the Secretary, Securities and Exchange Commission, 450 Fifth Street, NW., Washington, DC 20549–0609. Comments may also be submitted electronically at the following e-mail address: *rule-comments@sec.gov*. All comment letters should refer to File No. SR–FICC–2003–01. 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, comments should be sent in hardcopy or by e-mail but not by both methods. 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 Section, 450 Fifth Street, NW., Washington, DC 20549. Copies of such filing will also be available for inspection and copying at the principal office of FICC and on FICC's Web site at *http://www.ficc.com*. All submissions should refer to the File No. SR–FICC–2003–01 and should be submitted by February 20, 2004.

For the Commission by the Division of Market Regulation, pursuant to delegated authority.[5]

Jill M. Peterson,

Assistant Secretary.

[FR Doc. 04–1955 Filed 1–29–04; 8:45 am]

BILLING CODE 8010–01–P

broker-dealer participants) may have other similar regulatory notification requirements (imposed by the Commission or another regulator or similar authority) when their capital levels or other financial requirements fall below required levels. The rules of the Mortgage Backed Securities Division were recently amended to include the requirement that participants submit such notifications to FICC concurrently with their submission to the relevant regulatory authority. (*See* amendment 3 to SR-MBSCC–2001–06, Securities Exchange Act Release No. 45604 (March 20, 2002), 67 FR 14755, which is currently pending with the Commission). This present rule filing imposes the same requirement in the rules of the Government Securities Division.

[5] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–49127; File No. SR–MSRB–2003–07]

Self-Regulatory Organizations; Municipal Securities Rulemaking Board.; Order Approving Proposed Rule Change and Notice of Filing and Order Granting Accelerated Approval to Amendment No. 1 Relating to Proposed Amendment to the MSRB's Telemarketing Rules to Require Participation In the National Do-Not-Call Registry

January 26, 2004.

I. Introduction

On August, 19, 2003, the Municipal Securities Rulemaking Board ("MSRB"), filed with the Securities and Exchange Commission ("Commission" or "SEC"), pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 ("Act")[1] and Rule 19b–4 thereunder,[2] a proposed rule change relating to the MSRB's adoption of telemarketing rules to require brokers, dealers and municipal securities dealers (collectively "dealers") to participate in the national do-not-call registry. The proposed rule change was published for comment in the **Federal Register** on August 27, 2003.[3] On January 21, 2003, the MSRB submitted Amendment No. 1 to the proposed rule change.[4]

The Commission received three comment letters on the proposed rule change.[5] The text of proposed Amendment No. 1 is below. Additions from the original filing are in *italics*; deletions are in [brackets].

* * * * *

Rule G–39. Telemarketing

(a)–(f) No change.

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] The Commission published the proposed rule changes filed by the MSRB and the NASD simultaneously. *See* Securities Exchange Act Release Nos. 48389 (August 22, 2003), 68 FR 51609 (August 27, 2003) (SR-MSRB–2003–07); 48390 (August 22, 2003), 68 FR 51613 (August 27, 2003) (SR-NASD–2003–131).

[4] *See* letter from Ronald W. Smith, Senior Legal Associate, MSRB to Martha M. Haines, Office Chief, Division of Market Regulation, Commission, dated January 21, 2004 ("Amendment No. 1").

[5] *See* letters from Mary Talbutt-Glassberg, Fixed Income Trader, Davidson Capital Management, to MSRB, dated Aug. 20, 2003 ("Davidson Letter"); Ted F. Angus, V.P. and Senior Corporate Counsel for Retail Brokerage, Charles Schwab, to Mr. Jonathan G. Katz, Secretary, Commission, dated September 17, 2003, ("Schwab Letter"); and James Y. Chin, A.V.P., Director and Counsel, State Government Affairs & Staff Advisor to the State Telemarketing Subcommittee, Securities Industry Association, to Mr. Jonathan G. Katz, Secretary, Commission, dated September 17, 2003, ("SIA Letter").

(g) Definitions

(i) Established business relationship.

(A) An established business relationship exists between a broker, dealer or municipal securities dealer and a person if:

(1) the person has made a financial transaction *or has a security position, a money balance, or account activity* with the broker, dealer or municipal securities dealer *or at a clearing firm that provides clearing services to such broker, dealer or municipal securities dealer* within the [previous] eighteen months immediately preceding the date of the telemarketing call; [or]

(2) the broker, dealer or municipal securities dealer is the broker, dealer or municipal securities dealer of record for an account of the person within the eighteen months immediately preceding the date of the telemarketing call; or

[(2)]*(3)* the person has contacted the broker, dealer or municipal securities dealer to inquire about a product or service offered by the broker, dealer or municipal securities dealer within the [previous] three months immediately preceding the date of the telemarketing call.

(B) A person's established business relationship with a broker, dealer or municipal securities dealer does not extend to the broker, dealer or municipal securities dealer's affiliated entities unless the person would reasonably expect them to be included. Similarly, a person's established business relationship with a broker, dealer or municipal securities dealer's affiliate does not extend to the broker, dealer or municipal securities dealer unless the person would reasonably expect the broker, dealer or municipal securities dealer to be included.

(ii)–(iii) (No change).

(iv) the term "account activity" shall include, but not be limited to, purchases, sales, interest credits or debits, charges or credits, dividend payments, transfer activity, securities receipts or deliveries, and/or journal entries relating to securities or funds in the possession or control of the broker, dealer or municipal securities dealer.

(v) the term "broker, dealer or municipal securities dealer of record" refers to the broker, dealer or municipal securities dealer identified on a customer's account application for accounts held directly at an issuer of municipal fund securities or by the issuer's agent.

* * * * *

II. Description

A. General

The Federal Trade Commission ("FTC") and the Federal Communications Commission ("FCC") established requirements for sellers and telemarketers to participate in a national do-not-call registry.[6] Since June 2003, consumers have been able to enter their home and mobile telephone numbers into the national do-not-call registry, which is maintained by the FTC. Under rules of the FTC and FCC, sellers and telemarketers generally are prohibited from making telephone solicitations to consumers whose numbers are listed in the national do-not-call registry.

On July 2, 2003, the SEC requested that the MSRB amend its telemarketing rules to include a requirement for dealers to participate in the national do-not-call registry.[7] Because broker/dealers and banks are subject to the FCC's jurisdiction, the MSRB modeled its rules after the FCC, specifically tailoring the rules to broker/dealers and the securities industry.[8]

The MSRB submitted a proposed rule change to amend MSRB Rule G–39, to implement rules that prohibit dealers from making telemarketing calls to people who have registered on the FTC's national do-not-call registry.[9] The proposal retains the requirement that dealers make their a telemarketing calls only during certain times of day (8 a.m. to 9 p.m. local time at the called party's location) and a restriction against making calls to persons who have requested to be on a firm-specific do-not-call list.[10]

B. Exceptions

The MSRB currently provides dealers with an "existing customer" exception to its requirement that dealers make their a telemarketing calls only during certain times of day (8 a.m. to 9 p.m. local time at the called party's location) and to its requirement that dealers provide certain information about the caller during the course of the telephone conversation.[11] The proposed rule change would replace the "existing customer" exception with an "established business relationship" exception, a "prior express invitation or permission" exception and a "personal relationship exception."[12]

As originally proposed, the established business relationship exception would have enabled dealers to make a telephone solicitation as long as the call's recipient had made a financial transaction with the dealer within 18 months preceding the date of the telemarketing call, or if the recipient had contacted the dealer to inquire about a product or service offered by the dealer within the three months preceding the date of the telemarketing call.[13] The proposed established business relationship exception would not provide an exception for those individuals who have requested to be put on a dealer's firm-specific do-not-call list or from the time-of-day restrictions.

The second exception to the national do-not-call rules pertains to those persons from whom the dealer has obtained prior express written invitation or permission to make a telemarketing call.[14] The final exception pertains to those persons with whom an associated person of a dealer has a "personal relationship."[15]

C. Telemarketing Procedures

The MSRB also proposed that dealers must institute certain procedures related to do-not-call lists. As proposed, these procedures must include requirements to: Have a written policy for maintaining a do-not-call list, train personnel engaged in telemarketing in the existence and use of the do-not-call list, record and disclose requests from a person to be added to the dealer's do-not-call list, and have the dealer provide the called party with the name of the individual caller, the name of the dealer, a telephone number or address at which the dealer may be contacted, and that the purpose of the call is to solicit the purchase of securities or related services.[16] The proposed rules clarify that, absent a specific request, a person's do-not-call request would apply to the dealer making a call, but not an affiliated entity of such a dealer unless the person would expect such an affiliated entity to be included, given the identification of the caller and the product being advertised.[17] Further, the MSRB proposed that dealers must maintain a record of a caller's request to receive no further telemarketing calls

[6] Rules and Regulations Implementing the Telephone Consumer Protection Act of 1991 ("TCPA"), FCC 03–153, adopted June 26, 2003.

[7] The Telemarketing and Consumer Fraud and Abuse Prevention Act of 1994 requires the Commission to promulgate telemarketing rules substantially similar to those of the FTC or direct self-regulatory organizations to do so, unless the Commission determines that such rules are not in the interest of investor protection. 15 U.S.C. 6102(d) (2003).

[8] *See* The Do-Not-Call Implementation Act, 108 Pub. L. 10, 117 Stat. 557 (Mar. 11, 2003).

[9] *See* proposed MSRB Rule G–39(a)(iii).

[10] *See* proposed MSRB Rule G–39(a)(i) and (ii).

[11] *See* MSRB Rule G–39(h)(i) and (b)(ii).

[12] *See* proposed MSRB Rule G–39(b).

[13] *See* original proposed MSRB Rule G–39(g)(i)(A).

[14] *See* proposed MSRB Rule G–39(b)(ii).

[15] *See* proposed MSRB Rule G–39(b)(iii).

[16] *See* proposed MSRB Rule G–39(d)(i)—(d)(iv).

[17] *See* proposed MSRB Rule G–39(d)(v).

and must honor that request for a period of five years.[18]

D. Safe Harbor

In addition to proposing certain baseline procedures that dealers must follow, the MSRB proposed a "safe harbor" under which a dealer would not be liable for calling a person on the national do-not-call registry if that call is the result of an error and if the telemarketer's routine business practice meets certain specified standards.[19] In order to benefit from this safe harbor the dealer must establish and implement written procedures to comply with the national do-not-call rules, train its personnel in those procedures, maintain a list of telephone numbers that the dealer may not contact, and use a process to prevent telephone solicitations to any telephone number that appears on any national do-not-call registry, including a version of the list obtained from the administrator.

E. Miscellaneous

The MSRB proposed that the applicability of the telemarketing and telephone solicitation restrictions and exceptions would extend to wireless telephone subscribers.[20] Further, the MSRB proposed that if a dealer uses another entity to perform telemarketing services on its behalf, the dealer remains responsible for ensuring compliance with all provisions contained in proposed MSRB Rule G–39.[21]

III. Summary of Comments

The commission received three comment letters addressing the proposed rule change.[22] All three letters expressed concerns with the MSRB's proposed amendments to MSRB Rule G–39.

In general, two commenters believe that the proposed rule change, as proposed in the original filing, would restrict the ability of dealer firms to contact their existing customers.[23] The commenters' primary concern relates to the MSRB's proposed definition of an "established business relationship" exception.[24] The commenters generally stated the MSRB's proposed version of the established business relationship exception, which is created when a customer has made a financial transaction with a dealer, is too limited in scope and appears inconsistent with the TCPA and FCC Rules.

The established business relationship exclusion, under the FCC's amendment to the TCPA, provides that formation of an existing relationship involves a voluntary two-way communication "with or without an exchange of consideration." [25] By limiting the scope of the established business relationship exclusion, one commenter believes that the proposed rule change restricts opportunities for both dealers and customers.[26]

In addition, commenters expressed concerns that changing the interpretation from a customer that "carries an account" to requiring a "financial transaction" within the previous eighteen months imposes difficult compliance issues, increases confusion, and generally restricts the ability of dealers to contact their customers. These commenters believe the change undermines the broker-client relationship. In addition, some commenters claimed that narrowing the scope of existing customers for the established business relationship exception would force dealers to implement costly system changes that distinguish among their account holders.[27] As a whole, the commenters assert that the MSRB is setting forth a new concept that was not included in the FCC Rules under the amended TCPA.[28]

Two commenters believe that the MSRB's definition of an established business relationship is too narrow and omits various situations under which a broker/dealer may need to contact its customers.[29] These commenters state that the proposed definition of an established business relationship is significantly narrower than the MSRB's definition of existing customer, which is used for MSRB's existing telemarketing rules and the FCC's and FTC's definition of established business relationship.[30] Two commenters also believe that an established business relationship generally should exist when a customer is an account holder at a dealer.[31] Charles Schwab states that the proposed rule should permit a dealer to win back a customer's account.[32]

The commenters request a review of the proposal with consideration of the wide array of business activities of all dealer firms. One commenter urged the MSRB to revise the proposed rule change by expanding the definition of "established business relationship" to accommodate an effective means for dealers to deliver products and services to customers.[33]

IV. Amendment No. 1

In its letter included within Amendment No. 1, MSRB noted that proposed MSRB Rule G–39 would restrict only "telephone solicitations," which would be defined as "the initiation of a telephone call or message for the purpose of encouraging the purchase or rental of, or investment in, property, goods, or services, which is transmitted to any person." Accordingly, under the original proposed definition, the MSRB interpreted a telephone call to a customer concerning a margin call or similar administrative event would not constitute a telephone solicitation.

In response to commenters' concerns about the narrow scope of the established business relationship exception, the MSRB stated that a dealer may, at times, be compelled to contact a customer to satisfy the dealer's attendant agency obligations, including situations where market swings, interest rate changes, new tax laws, or specific industry or company news may necessitate a broker contacting his or her customer.

In addition, the MSRB proposed two changes to the definition of an "established business relationship." The first change to the definition would encompass situations where the person has a security position, a money balance, or account activity at a clearing firm on behalf of such dealer within the previous 18 months. The second change to the definition would include situations where a dealer was the "broker, dealer or municipal securities dealer of record" for an account of a person within the 18 months immediately preceding the date of the telemarketing call. Both definitions of established business relationship continue for 18 months after a triggering event, thus providing an opportunity for a firm to win back a customer.

Moreover, the MSRB noted that the proposed rule change, as amended, cannot assure dealers that compliance with the proposed MSRB Rule G–39

[18] *See* proposed MSRB Rule G–39(d)(vi).

[19] *See* proposed MSRB Rule G–39(c).

[20] *See* proposed MSRB Rule G–39(e).

[21] *See* proposed MSRB Rule G–39(f).

[22] *See supra* note 5.

[23] *See* Charles Schwab Letter, at 4; SIA Letter, at 4.

[24] *Id.*

[25] 47 CFR 64.1200(f)(3).

[26] *See* Davidson Letter.

[27] *See* Schwab Letter, at 5; SIA Letter, at 2.

[28] *See* Schwab Letter; SIA Letter.

[29] *See* Schwab Letter, at 4; SIA Letter, at 4.

[30] *See* SIA Letter, at 3–4; Charles Schwab Letter at 2–4.

[31] *See* SIA Letter at 3; and Schwab Letter at 3.

[32] See Schwab Letter, at 5. The FCC has stated, "a consumer who once had telephone service with a particular carrier or a subscription with a particular newspaper could expect to receive a call from those entities in an effort to "win back" or "renew" that consumer's business within eighteen (18) months." 68 FR 44144, 44158 (July 25, 2003).

[33] *See* SIA Letter, at 4.

ensures compliance with FCC rules because dealers also must comply with the telemarketing rules of the FCC and any FCC interpretations of those rules.

V. Discussion and Commission Findings

After careful review of the proposed rule change, as amended, and the related comments, the Commission finds that the proposed rule change, as amended, is consistent with the requirements of the Act and the rules and regulations thereunder which govern the MSRB [34] and, in particular, the requirements of Section 15B(b)(2)(C) of the Act and the rules and regulations thereunder.[35] Section 15B(b)(2)(C) of the Act requires, among other things, that MSRB's rules must be designed to prevent fraudulent and manipulative acts and practices, to promote just and equitable principles of trade, and, in general, to protect investors and the public interest.

A. General

The Commission believes that the investing public's participation in the do-not-call registry, as described in the proposed rule change, creates an expectation among national do-not-call registrants that they will not receive unwanted telephone solicitations from dealers. The Commission believes that the MSRB's proposal generally prohibits its dealers from making telemarketing calls to people who have registered on the national do-not-call registry, while retaining time-of-day and firm-specific do-not-call list restrictions.[36] The Commission believes that the proposed rule change, as amended, establishes adequate procedures to prevent dealers from making telephone solicitations to do-not-call registrants, which should have the effect of protecting investors, while providing appropriate exception to the rule for certain enumerated situations, which should promote just and equitable principles of trade.

B. Exceptions

The Commission recognizes the importance of having certain exceptions to the general prohibition of dealers from soliciting persons who have signed up on the FCC's national do-not-call registry. The Commission believes that the "established business relationship" exception, "prior express invitation or permission" exception, and a "personal relationship" exception provide appropriate scenarios where dealer should not be precluded from making a telemarketing call to do-not-call registrants.

The Commission further believes that the MSRB's expansion of "established business relationship" is appropriate. As originally drafted, an established business relationship would exist between the customer and a dealer as long as the call's recipient had made a financial transaction with the dealer within 18 months preceding the date of the telemarketing call, or if the recipient had contacted the dealer to inquire about a product or service offered by the dealer within the three months preceding the date of the telemarketing call.[37] In response to commenters concerns about the narrowness of the exception, the MSRB expanded the definition of "established business relationship" to include situations where the telemarketing call recipient has a security position, a money balance, or account activity at a clearing firm on behalf of such dealer within the previous 18 months, and where a dealer was the "broker/dealer of record" for an account of a person within the 18 months immediately preceding the date of the telemarketing call.

The Commission believes that a dealer should be able to discuss the purchase or sale of a security with a customer who has registered on the national do-not-call registry without fear of violating an MSRB rule when there is some development that could materially impact the investment decision of a reasonable investor. As originally proposed, an established business relationship did not exist unless an account holder had made a financial transaction within the previous eighteen months or affirmatively contacted the dealer to make an account inquiry within the past three months. The Commission believes that the definition, as originally proposed, would have restricted a dealer from making a telemarketing call to its customer in many situations where a prudent investor would ordinarily desire to be contacted, such as the existence of market swings, interest rate changes, new tax laws, or specific industry or company news. The Commission believes that the expansion of the definition of "established business relationship" exception to include persons that have a security position, money balance or account activity with a dealer or at a clearing firm that provides clearing services on behalf of a dealer will, among other things, assist dealers in upholding their agency obligations to customers. In addition, the Commission believes that broker/dealers of record who have served as such for a customer within the eighteen months preceding the date of the telemarketing call should be allowed to contact a customer whose account is held directly at an issuer of a municipal fund or by the issuer's agent.

Moreover, the Commission believes that the proposed established business relationship exception adequately protects customers who are most interested in not being contacted by a dealer by specifying that the exception does not apply to those individuals who have specifically requested to be put on a dealer's do-not-call list. The Commission further believes a dealer should not generally be restricted from contacting those do-not-call registrants from whom the dealer has received express written consent to contact and those registrants who have a personal relationship with the associated person making the call.

C. Telemarketing Procedures

As described above, the MSRB also proposed that dealers must institute certain procedures related to do-not-call lists.[38] The Commission believes that the procedures that the MSRB has proposed provide adequate guidelines for a dealer to establish education and training of its affiliated persons and adequately provides that a dealer will incorporate the names of persons who request to be put on a firm's do-not-call list among the list of names that a dealer may not contact. Further, the Commission believes that the identification procedure that a dealer or associated person must follow when making a telemarketing call should enhance the ability of consumers to hold dealers accountable for adhering to firm-specific and national do-not-call registry restrictions.

D. Safe Harbor

As described above, the MSRB proposed "safe harbor" procedures that a dealer could follow to avoid liability for do-not-call list violations that arise out of errors if the telemarketer's routine business practice meets certain specified standards.[39] The Commission believes that the safe harbor that the MSRB has proposed should ensure that a dealer incorporates national do-not-call registrants in its own list of telephone numbers that it may not contact, and that dealers follow procedures to refrain from contacting such persons. Accordingly, the

[34] In addition, in approving this rule the Commission notes that it has considered the proposed rule's impact on efficiency, competition and capital formation. 15 U.S.C. 78c(f).

[35] 15 U.S.C. 78o–4(b)(2)(C).

[36] *See* proposed MSRB Rule G–39(a)(i)—(a)(iii).

[37] *See* original proposed MSRB Rule G–39(g)(i)(A).

[38] *See* proposed MSRB Rule G–39(d)(i)–(d)(6).

[39] *See* proposed MSRB Rule G–39(c).

Commission believes it is appropriate for the MSRB to grant dealers who have established the appropriate routine business practices a safe harbor exemption from liability for calls made out of genuine error.

E. Miscellaneous

The Commission believes that the MSRB's proposal to apply the telemarketing and telephone solicitation restrictions to wireless telephone numbers is appropriate, given that consumers can register wireless telephone numbers in the national do-not-call registry. Further, the Commission believes that a dealer should not be able to avoid accountability for complying with telemarketing restrictions and regulations by employing another entity to perform telemarketing services on behalf of the dealer. Accordingly, the Commission finds proposed MSRB Rule G–39(f), relating to outsourcing telemarketing, to be appropriate.

F. Accelerated Approval of Amendment No. 1

The Commission finds good cause, pursuant to section 19(b)(2) of the Act, for approving Amendment No. 1 prior to the thirtieth day after the date of publication of notice thereof in the **Federal Register**. As discussed above, in Amendment No. 1, the MSRB expanded the breadth of the established business relationship exception. The Commission believes that the proposed Amendment No. 1 will, among other things, facilitate dealers' ability to uphold their agency obligations by enabling them to make a telemarketing call under certain circumstances to customers who have not actively traded or made deposits to their brokerage accounts. In making the determination to accelerate approval of Amendment No. 1, the Commission notes that the majority of commenters supported a broader definition of "established business relationship."[40]

VI. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning Amendment No. 1, including whether Amendment No. 1 is consistent with the Act. Persons making written submissions should file six copies thereof with the Secretary, Securities and Exchange Commission, 450 Fifth Street, NW., Washington, DC 20549–0609. Comments may also be submitted electronically at the following e-mail address: *rule-comments@sec.gov*. All comment letters should refer to File No. SR–MSRB–2003–07. 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, comments should be sent in hardcopy or by e-mail but not by both methods. Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for inspection and copying in the Commission's Public Reference Room. Copies of such filing also will be available for inspection and copying at the principal office of the MSRB. All submissions should refer to File No. SR–MSRB–2003–07 and should be submitted by February 20, 2004.

VII. Conclusion

It is therefore ordered, pursuant to section 19(b)(2) of the Act,[41] that the proposed rule change, as amended (File No. SR–MSRB–2003–07) is approved, and Amendment No. 1 is approved on an accelerated basis.

For the Commission, by the Division of Market Regulation, pursuant to delegated authority.[42]

Jill M. Peterson,

Assistant Secretary.

[FR Doc. 04–1956 Filed 1–29–04; 8:45 am]

BILLING CODE 8010–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–49126; File No. SR–OCC–2003–07]

Self-Regulatory Organizations; the Options Clearing Corporation; Notice of Filing and Immediate Effectiveness of a Proposed Rule Change Relating to the Clearance and Settlement of Foreign Currency Futures

January 26, 2004.

Pursuant to section 19(b)(1) of the Securities Exchange Act of 1934 ("Act"),[1] notice is hereby given that on August 4, 2003, the Options Clearing Corporation ("OCC") filed with the Securities and Exchange Commission ("Commission") and on November 17, 2003, amended the proposed rule change as described in items I, II, and III below, which items have been prepared primarily by OCC. 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 proposed rule change accommodates the introduction of foreign currency futures as proposed to be traded by the Philadelphia Board of Trade ("PBOT") and cleared by OCC.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, OCC 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. OCC has prepared summaries, set forth in sections (A), (B), and (C) below, of the most significant aspects of such statements.[2]

(A) Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

The proposed amendments provide for the clearance and settlement of cash-settled futures of foreign currency. The same basic rules and procedures currently applicable to other cash-settled futures contracts will be applicable to cash-settled foreign currency futures.

The by-laws and rules of PBOT provide for listing physically-settled foreign currency futures, which were historically cleared through The Intermarket Clearing Corporation ("IMM"), a subsidiary of OCC. PBOT now proposes to list cash-settled foreign currency futures for trading through its facilities, and OCC proposes to provide clearing and settlement services for these new contracts directly rather than through ICC. OCC would perform this function in its capacity as a derivatives clearing organization ("DCO") registered as such under the Commodity Exchange Act.

OCC's existing rules already provide for the clearance of cash-settled futures. They do not, however, specifically contemplate cash-settled futures for which a foreign currency is the underlying interest. The purpose of the present rule change is to amend the rules as necessary to provide for

[40] *See* Schwab Letter, at 4; SIA Letter, at 4.

[41] 15 U.S.C. 78s(b)(2).

[42] 17 CFR 200.30–3(a)(12).

[1] 15 U.S.C. 78s(b)(1).

[2] The Commission has modified parts of these statements.

clearance and settlement of this additional type of future.

The proposed cash-settled foreign currency futures will be cleared and settled in a manner similar to other cash-settled futures. Daily variation margin and final settlement prices for cash-settled foreign currency futures will be calculated by marking to the futures price as reported to OCC by PBOT. PBOT has informed OCC that, in the event that there is no recent price in the futures market or the futures price is otherwise deemed inappropriate for use, PBOT has the authority under its rules to use alternative means to determine a price for the underlying foreign currency. OCC has similar authority under its own rules.[3] Cash-settled foreign currency futures will be settled at maturity through a final variation payment made in U.S. dollars and not through delivery of the underlying currency.

The proposed changes include amendments and additions to the definitions in Article I of the By-Laws and to the rules governing Futures in Article XII of the By-Laws and Chapter XIII of the Rules. The following is brief description of the significant amendments and additions. Certain nonsubstantive changes intended to conform or make corrections to existing by-laws and rules are self-explanatory and not discussed below.

OCC proposes to add a definition of cash-settled foreign currency future in Article I of the By-Laws. The definitions of final settlement price and final variation payment have been included in order to correct the alphabetization.

Article XII sets out the basic provisions for futures and futures options. Section 3(a) contains a general expression of OCC's authority to make adjustments to the terms of futures and futures options to reflect relevant events affecting underlying interests. A sentence has been added to this section 3(a) which directs the reader to new section 4A for specific information about circumstances under which adjustments to cash-settled foreign currency futures might be made and about the process for making such determinations. New section 4A, including Interpretation .01 thereto, has been adapted from the adjustment provision for cash-settled foreign currency options in Article XXII, section 3 of the By-Laws. Section 6 of Article XII of the By-Laws is being amended to make clear that final settlement prices for futures contracts may be based upon prices or quotations in other markets for the relevant underlying interest, such as the cash or spot markets.

By-Laws in Article XXII apply only to cash-settled foreign currency options. Because of the potential for confusion and as guidance to the reader, a cross-reference has been added to the Introduction of this Article noting that rules governing cash-settled foreign currency futures appear in Article XII of the By-Laws and Chapter XIII of the Rules.

Chapter X of the Rules governs clearing fund contributions, and Rule 1001 governs the amount of contributions. Rule 1001 contains special provisions applicable to a clearing member who is an affiliate of a previously admitted clearing member and that becomes a clearing member solely for the purpose of clearing transactions in certain designated futures and futures options. The proposed amendment broadens the categories of contracts subject to the special provisions to include all commodity futures and options on commodity futures. A clearing member that qualifies for this special treatment is deemed to be in compliance with its minimum contribution requirement if the entity contributes the amount calculated with respect to it under the basic clearing fund formula, notwithstanding that such amount is less than the $150,000 minimum, so long as its previously admitted affiliate is in compliance with the $150,000 minimum.

OCC believes that the proposed rule change is consistent with the purposes and requirements of section 17A of the Act because it facilitates the establishment of linked or coordinated facilities for clearance and settlement of transactions in foreign currency options and cash-settled foreign currency futures and provides for the efficient clearance and settlement of the latter by adapting existing OCC rules previously approved as effective in promoting the prompt and accurate clearance and settlement of other types of futures contracts.

(B) Self-Regulatory Organization's Statement on Burden on Competition

OCC does not believe that the proposed rule change would impose any burden on competition.

(C) Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

Written comments were not and are not intended to be solicited with respect to the proposed rule change, and none have been received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The foregoing rule change has become effective pursuant to section 19(b)(3)(A)(iii) of the Act[4] and Rule 19b–4(f)(4)[5] thereunder because it effects a change in an existing service of OCC that (i) does not adversely affect the safeguarding of securities or funds in the custody or control of OCC or for which it is responsible and (ii) does not significantly affect the respective rights or obligations of OCC or persons using the service. At any time within 60 days of the filing of the proposed rule change, the Commission could have summarily abrogated such rule change if it appeared to the Commission that such action was 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. Persons making written submissions should file six copies thereof with the Secretary, Securities and Exchange Commission, 450 Fifth Street, NW., Washington, DC 20549–0609. Comments may also be submitted electronically at the following e-mail address: *rule-comments@sec.gov*. All comment letters should refer to File No. SR–OCC–2003–07. 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, comments should be sent in hardcopy or by e-mail but not by both methods. 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 Section, 450 Fifth Street, NW., Washington, DC 20549. Copies of such filing will also be available for inspection and copying at the principal office of OCC and on OCC's Web site at *http://www.optionsclearing.com*. All

[3] Article XII, section 5 of OCC's By-Laws and Chapter XIII, Rule 1301(d) of OCC's Rules.

[4] 15 U.S.C. 78s(b)(3)(A)(iii).

[5] 17 CFR 240.19b–4(f)(4).

submissions should refer to the File No. SR–OCC–2003–07 and should be submitted by February 20, 2004.

For the Commission by the Division of Market Regulation, pursuant to delegated authority.[6]

Jill M. Peterson,

Assistant Secretary.

[FR Doc. 04–1953 Filed 1–29–04; 8:45 am]

BILLING CODE 8010–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–49124; File No. SR–OCC–2003–06]

Self-Regulatory Organizations; The Options Clearing Corporation; Notice of Filing and Immediate Effectiveness of a Proposed Rule Change Relating to a Clearing Agreement

January 26, 2004.

Pursuant to section 19(b)(1) of the Securities Exchange Act of 1934 ("Act"),[1] notice is hereby given that on July 22, 2003, The Options Clearing Corporation ("OCC") filed with the Securities and Exchange Commission ("Commission") the proposed rule change as described in Items I, II, and III below, which items have been prepared primarily by OCC. 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 proposed rule change consists of the Agreement for Clearing and Settling Security Futures and Futures and Futures Options on Broad-Based Indexes between OCC and the Chicago Board Options Exchange ("CBOE").

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, OCC 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. OCC has prepared summaries, set forth in sections (A), (B), and (C) below, of the most significant aspects of such statements.[2]

[6] 17 CFR 200.30–3(a)(12).

[1] 15 U.S.C. 78s(b)(1).

[2] The Commission has modified parts of these statements.

(A) Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

The CBOE intends to open a futures exchange, to be known as CBOE Futures Exchange, LLC ("CFE"). CFE has applied to the Commodity Futures Trading Commission ("CFTC") for designation as a contract market and intends to notice register to be a limited purpose national securities exchange for the trading of futures before such trading commences. CFE and OCC have entered into a clearing agreement ("CFE Agreement") pursuant to which OCC will provide clearing and settlement services with respect to the security futures and futures and options on futures on broad-based security indexes that may be traded on CFE.[3] The CFE Agreement is substantially similar to OCC's amended and restated clearing agreement with Nasdaq Liffe Markets, LLC ("NQLX") but includes some terms taken from OCC's security futures clearing agreements with the Island Futures Exchange, LLC ("IFX") and OneChicago, LLC ("ONE"), which were previously filed with the Commission.[4] To the extent that terms of the CFE Agreement are not traceable to one of these sources, those terms are immaterial.

OCC believes that the proposed rule change is consistent with the purposes and requirements of section 17A of the Act because it will foster cooperation and coordination with persons engaged in the clearance and settlement of securities transactions and remove impediments to and perfect the mechanism of a national system for the prompt and accurate clearance and settlement of securities transactions.

(B) Self-Regulatory Organization's Statement on Burden on Competition

OCC does not believe that the proposed rule change will impose any burden on competition.

[3] OCC is registered as a "derivatives clearing organization" under the Commodity Exchange Act by order of the Commodity Futures Trading Commission (December 10, 2001). The Commission previously approved OCC's rule filing to clear futures and futures options on broad-based stock indexes. Securities Exchange Act Release No. 45946 (May 16, 2002), 67 FR 36056 (May 22, 2002), File No. [SR–OCC–2001–16].

[4] Securities Exchange Act Release Nos. 46722 (October 25, 2002), 67 FR 67230 (November 4, 2002) File No. [SR–OCC–2002–13] (amended and restated clearing agreement with NQLX), 46058 (June 10, 2002), 67 FR 41287 (June 17, 2002) File No. [SR–OCC–2002–08] (security futures clearing agreement with IFX), and 46653 (October 11, 2002), 67 FR 64689 (October 21, 2002) File No. [SR–OCC–2002–07] (security futures clearing agreement with ONE).

(C) Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received from Members, Participants, or Others

Written comments were not and are not intended to be solicited with respect to the proposed rule change, and none have been received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The foregoing rule change has become effective pursuant to section 19(b)(3)(A)(iii) of the Act[5] and Rule 19b–4(f)(4)[6] thereunder because it effects a change in an existing service of OCC that (i) does not adversely affect the safeguarding of securities or funds in the custody or control of OCC or for which it is responsible and (ii) does not significantly affect the respective rights or obligations of OCC or persons using the service. At any time within sixty days of the filing of the proposed rule change, the Commission could have summarily abrogated such rule change if it appeared to the Commission that such action was 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. Persons making written submissions should file six copies thereof with the Secretary, Securities and Exchange Commission, 450 Fifth Street, NW., Washington, DC 20549–0609. Comments may also be submitted electronically at the following e-mail address: *rule-comments@sec.gov*. All comment letters should refer to File No. SR–OCC–2003–06. 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, comments should be sent in hardcopy or by e-mail but not by both methods. 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

[5] 15 U.S.C. 78s(b)(3)(A)(iii).

[6] 17 CFR 240.19b–4(f)(4).

available for inspection and copying in the Commission's Public Reference Section, 450 Fifth Street, NW., Washington, DC 20549. Copies of such filing will also be available for inspection and copying at the principal office of OCC and on OCC's Web site at *http://www.optionsclearing.com*. All submissions should refer to the File No. SR–OCC–2003–06 and should be submitted by February 20, 2004.

For the Commission by the Division of Market Regulation, pursuant to delegated authority.[7]

Jill M. Peterson,

Assistant Secretary.

[FR Doc. 04–1954 Filed 1–29–04; 8:45 am]

BILLING CODE 8010–01–P

DEPARTMENT OF STATE

[Public Notice 4598]

30–Day Notice of Proposed Information Collection: Form DS–5501, Electronic Diversity Visa Entry Form; OMB Control Number 1405–0153

ACTION: Notice.

SUMMARY: The Department of State has submitted the following information collection request to the Office of Management and Budget (OMB) for approval in accordance with the Paperwork Reduction Act of 1995. Comments should be submitted to OMB within 30 days of the publication of this notice.

The following summarizes the information collection proposal submitted to OMB:

Type of Request: Extension of Currently Approved Collection.

Originating Office: Bureau of Consular Affairs, Department of State (CA/VO).

Title of Information Collection: Electronic Diversity Visa Entry Form.

Frequency: Once per respondent.

Form Number: DS–5501.

Respondents: Aliens entering the Diversity Visa Lottery.

Estimated Number of Respondents: 6 million per year.

Average Hours Per Response: .5 hours.

Total Estimated Burden: 3 million hours per year.

Public comments are being solicited to permit the agency to:

- Evaluate whether the proposed information collection 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, including the validity of the methodology and assumptions used.
- Enhance the quality, utility, and clarity of the information to be collected.
- Minimize the reporting burden on those who are to respond, including through the use of automated collection techniques or other forms of technology.

FOR FURTHER INFORMATION CONTACT: Copies of the proposed information collection and supporting documents may be obtained from Brendan Mullarkey of the Office of Visa Services, U.S. Department of State, 2401 E St. NW., RM L–703, Washington, DC 20520, who may be reached on (202) 663–1166. Public comments and questions should be directed to the State Department Desk Officer, Office of Information and Regulatory Affairs, Office of Management and Budget (OMB), Washington, DC 20530, who may be reached on (202) 395–3897.

Dated: January 13, 2004.

Janice L. Jacobs,

Deputy Assistant Secretary of State for Visa Services, Bureau of Consular Affairs, Department of State.

[FR Doc. 04–1961 Filed 1–29–04; 8:45 am]

BILLING CODE 4710–06–P

DEPARTMENT OF STATE

[Public Notice: 4597]

Determination Related to Colombian Armed Forces Under Section 564 of Foreign Operations, Export Financing, and Related Programs Appropriations Act, Division E, Consolidated Appropriations Resolution, 2003, (Public Law 108–7)

Pursuant to the authority vested in me as Secretary of State, including under section 564 of the Foreign Operations, Export Financing, and Related Programs Appropriations Act, Division E, Consolidated Appropriations Resolution, 2003, (Public Law 108–7) (the "FOAA"), I hereby determine and certify, in accordance with the conditions contained in section 564(a)(2), that: (A) The Commander General of the Colombian Armed Forces is suspending from the Armed Forces those members, of whatever rank, who have been credibly alleged to have committed gross violations of human rights, including extra-judicial killings, or to have aided or abetted paramilitary organizations; (B) The Colombian Government is prosecuting those members of the Colombian Armed Forces, of whatever rank, who have been credibly alleged to have committed gross violations of human rights, including extra-judicial killings, or to have aided or abetted paramilitary organizations, and is punishing those members of the Colombian Armed Forces found to have committed such violations of human rights or to have aided or abetted paramilitary organizations; (C) The Colombian Armed Forces are cooperating with civilian prosecutors and judicial authorities in such cases, (including providing requested information, such as the identity of the persons suspended from the Armed Forces and the nature and cause of the suspension, and access to witnesses, relevant military documents and other requested information); (D) The Colombian Armed Forces are severing links (including denying access to military intelligence, vehicles, and other equipment or supplies, and ceasing other forms of active or tacit cooperation), at the command, battalion, and brigade levels, with paramilitary organizations; (E) The Colombian Armed Forces are executing orders for capture of leaders of paramilitary organizations that continue armed conflict; and that, as required in section 564(a)(3), the Colombian Armed Forces are conducting vigorous operations to restore government authority and respect for human rights in areas under the effective control of paramilitary and guerrilla organizations.

The Department of State has consulted with internationally recognized human rights organizations regarding the Colombian Armed Forces' progress in meeting the conditions contained in section 564(a)(2), as required in section 564(b).

This Determination shall be published in the **Federal Register** and copies shall be transmitted to the appropriate committees of Congress.

Colin L. Powell,

Secretary of State, Department of State.

[FR Doc. 04–1962 Filed 1–29–04; 8:45 am]

BILLING CODE 1410–29–P

DEPARTMENT OF STATE

[Public Notice 4601]

Millennium Challenge Corporation Board of Directors; Sunshine Act Meeting

AGENCY: Millennium Challenge Corporation, Department of State.

The Department of State is publishing this notice on behalf of the Millennium Challenge Corporation, pursuant to 5 U.S.C. 552b(e).

TIME AND DATE: 4–5 p.m., February 2, 2004; Open session to begin at 4 p.m.

[7] 17 CFR 200.30–3(a)(12).

with closed session be held immediately following open session.

PLACE: Department of State, C Street Entrance, Washington, DC 20520.

FOR FURTHER INFORMATION CONTACT: Information on the meeting may be obtained from Ghadah Sabbagh at (202) 647–6286.

STATUS: Meeting open to the public from 4 p.m. until conclusion of the open session; closed session will commence immediately following the conclusion of the open session.

MATTERS TO BE CONSIDERED: The Board of Directors (the "Board") of the Millennium Challenge Corporation ("MCC") will hold an initial meeting of the Board to discuss certain MCC operational and administrative matters and the identification of countries, which will be candidates for assistance in FY2004 under Title VI of the Foreign Operations, Export Financing, and Related Programs Appropriations Act, 2004. Other than with respect to the portion of the meeting relating to potential candidate countries, which is expected to involve the consideration of classified information, the meeting will be conducted in an open session. A closed session, if necessary and approved by the Board, will be held immediately following the open session.

Due to security requirements at the meeting location, all individuals wishing to attend the open session of the meeting must notify Ghadah Sabbagh at (202) 647–6286 (sabbaghgb@state.gov) of their intention to attend the meeting by noon on Friday, January 30, 2004 and must comply with all relevant security requirements of the Department of State, including providing the necessary information to obtain any required clearance. Seating for the open session will be available on a first come, first served basis.

Dated: January 28, 2004.

Alan Larson,

Undersecretary for Economic, Business and Agricultural Affairs, Department of State.

[FR Doc. 04–2058 Filed 1–28–04; 2:14 pm]

BILLING CODE 4710–07–P

DEPARTMENT OF TRANSPORTATION

Office of the Secretary

[Docket No. OST 2004–16951]

Notice of Request of a Previously Approved Collection

AGENCY: Office of the Secretary.

ACTION: Notice and request for comments.

SUMMARY: In accordance with the Paperwork Reduction Act of 1995, this notice announces the Department of Transportation's (DOT) intention to request extension of a previously approved information collection.

DATES: Comments on this notice must be received by March 30, 2004.

ADDRESSES: You may submit comments [identified by DOT–DMS Docket Number OST–2004–16951 by any of the following methods:

- Web Site: *http://dms.dot.gov.* 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, 400 Seventh Street, SW., Nassif Building, Room PL–401, Washington, DC 20590–001.
- *Hand Delivery:* Room PL–401 on the plaza level of the Nassif Building, 400 Seventh Street, SW., Washington DC, between 9 a.m. and 5 p.m., Monday through Friday, except on 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 or Regulatory Identification Number (RIN) for this rulemaking. For detailed instructions on submitting comments and additional information on the rulemaking process, see the Public Participation heading of the Supplementary Information section of this document. 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 under Regulatory Notes.

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 PL–401 on the plaza level of the Nassif Building, 400 Seventh Street, SW., Washington, DC, between 9 a.m. and 5 p.m. Monday through Friday, except on Federal holidays.

FOR FURTHER INFORMATION CONTACT: Delores King, Air Carrier Fitness Division (X–56), Office of Aviation Analysis, Office of the Secretary, U.S. Department of Transportation, 400 Seventh Street, SW., Washington, DC 20590, (202) 366–2343.

SUPPLEMENTARY INFORMATION:

Title: Aircraft Accident Liability Insurance.

OMB Control Number: 2106–0030.

Type of Request: Extension without change of a previously approved collection.

Abstract: 14 CFR Part 205 contains the minimum requirements for air carrier accident liability insurance to protect the public from losses, and directs that certificates evidencing appropriate coverage must be filed with the Department.

Respondents: U.S. and foreign air carriers.

Estimated Number of Respondents: 4,270.

Estimated Total Burden on Respondents: 2,762.5 hours.

Comments are invited on: (a) Whether the proposed collection of information is necessary for the proper performance of the functions of the Department, including whether the information will have practical utility; (b) the accuracy of the Department's estimate of the burden of the proposed information collection; (c) ways to enhance quality, utility, and clarity of the information to be collected; and (d) ways to minimize the burden of the collection of information on respondents, including the use of automated collection techniques or other forms of information technology.

All respondents to this notice, will be summarized and included in the request to OMB approval. All comments will also become a matter of public record.

Issued in Washington, DC on January 22, 2004.

Randall D. Bennett,

Director, Office of Aviation Analysis.

[FR Doc. 04–1940 Filed 1–29–04; 8:45 am]

BILLING CODE 4910–62–P

Corrections

Federal Register
Vol. 69, No. 20
Friday, January 30, 2004

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 TRANSPORTATION

Federal Highway Administration

Environmental Impact Statement: Multiple South and East Texas Counties, State of Texas

Correction

In notice document 04–866 beginning on page 2382 in the issue of Thursday, January 15, 2004 make the following correction:

On page. 2382, in the third column, under the **SUMMARY:** heading, in the sixth line, after "69) from" add "near Shreveport, Louisiana and Texarkana, Texas to the Texas-Mexico international border".

[FR Doc. C4–866 Filed 1–29–04; 8:45 am]

BILLING CODE 1505–01–D

DEPARTMENT OF THE TREASURY

Internal Revenue Service

26 CFR Part 1

[TD 9108]

RIN 1545–BC76

Confidential Transactions

Correction

In rule document 03–31900 beginning on page 75128 in the issue of Tuesday, December 30, 2003, make the following correction:

§ 1.6011–4 [Corrected]

On page 75130, in § 1.6011–4, in the second column, after paragraph (b)(3)(v), add

"* * * * *"

to the end of the paragraph.

[FR Doc. C3–31900 Filed 1–29–04; 8:45 am]

BILLING CODE 1505–01–D

Federal Register

Friday
January 30, 2004

Part II

Reader Aids

Cumulative List of Public Laws
108th Congress, First Session

CUMULATIVE LIST OF PUBLIC LAWS

This is the cumulative list of public laws for the 108th Congress, First Session. Other cumulative lists (1993-2003) are available online at *http://www.archives.gov/federal_register/public_laws/public_laws.html*. Comments may be addressed to the Director, Office of the Federal Register, Washington, DC 20408 or send e-mail to info@nara.fedreg.gov.

The text of laws may be ordered in individual pamphlet form (referred to as "slip laws") from the Superintendent of Documents, U.S. Government Printing Office, Washington, DC 20402 (phone, 202–512–2470). 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 online or for purchase.

Public Law	Title	Approved	117 Stat.
108–1	To provide for a 5-month extension of the Temporary Extended Unemployment Compensation Act of 2002 and for a transition period for individuals receiving compensation when the program under such Act ends.	Jan. 8, 2003	3
108–2	Making further continuing appropriations for the fiscal year 2003, and for other purposes	Jan. 10, 2003	5
108–3	National Flood Insurance Program Reauthorization Act of 2003	Jan. 13, 2003	7
108–4	Making further continuing appropriations for the fiscal year 2003, and for other purposes	Jan. 31, 2003	8
108–5	Making further continuing appropriations for the fiscal year 2003, and for other purposes	Feb. 7, 2003	9
108–6	To authorize salary adjustments for Justices and judges of the United States for fiscal year 2003.	Feb. 13, 2003	10
108–7	Consolidated Appropriations Resolution, 2003	Feb. 20, 2003	11
108–8	To improve the calculation of the Federal subsidy rate with respect to certain small business loans, and for other purposes.	Feb. 25, 2003	555
108–9	Recognizing the 92d birthday of Ronald Reagan	Mar. 6, 2003	556
108–10	Do-Not-Call Implementation Act	Mar. 11, 2003	557
108–11	Emergency Wartime Supplemental Appropriations Act, 2003	Apr. 16, 2003	559
108–12	To reinstate and extend the deadline for commencement of construction of a hydroelectric project in the State of Illinois.	Apr. 22, 2003	612
108–13	To rename the Guam South Elementary/Middle School of the Department of Defense Domestic Dependents Elementary and Secondary Schools System in honor of Navy Commander William "Willie" McCool, who was the pilot of the Space Shuttle Columbia when it was tragically lost on February 1, 2003.	Apr. 22, 2003	613
108–14	To designate the Federal building located at 290 Broadway in New York, New York, as the "Ted Weiss Federal Building".	Apr. 23, 2003	614
108–15	American 5-Cent Coin Design Continuity Act of 2003	Apr. 23, 2003	615
108–16	Nutria Eradication and Control Act of 2003	Apr. 23, 2003	621
108–17	To designate the facility of the United States Postal Service located at 2127 Beatties Ford Road in Charlotte, North Carolina, as the "Jim Richardson Post Office".	Apr. 23, 2003	623
108–18	Postal Civil Service Retirement System Funding Reform Act of 2003	Apr. 23, 2003	624
108–19	Clean Diamond Trade Act	Apr. 25, 2003	631
108–20	Smallpox Emergency Personnel Protection Act of 2003	Apr. 30, 2003	638
108–21	Prosecutorial Remedies and Other Tools to end the Exploitation of Children Today Act of 2003.	Apr. 30, 2003	650
108–22	Gila River Indian Community Judgment Fund Distribution Act of 2003	May 14, 2003	696
108–23	Ottawa National Wildlife Refuge Complex Expansion and Detroit River International Wildlife Refuge Expansion Act.	May 19, 2003	704
108–24	Increasing the statutory limit on the public debt	May 27, 2003	710
108–25	United States Leadership Against HIV/AIDS, Tuberculosis, and Malaria Act of 2003	May 27, 2003	711
108–26	Unemployment Compensation Amendments of 2003	May 28, 2003	751
108–27	Jobs and Growth Tax Relief Reconciliation Act of 2003	May 28, 2003	752
108–28	Concerning participation of Taiwan in the World Health Organization	May 29, 2003	769
108–29	Veterans' Memorial Preservation and Recognition Act of 2003	May 29, 2003	772
108–30	To amend the Richard B. Russell National School Lunch Act to extend the availability of funds to carry out the fruit and vegetable pilot program.	May 29, 2003	774
108–31	To amend the Microenterprise for Self-Reliance Act of 2000 and the Foreign Assistance Act of 1961 to increase assistance for the poorest people in developing countries under microenterprise assistance programs under those Acts, and for other purposes.	June 17, 2003	775
108–32	Grand Teton National Park Land Exchange Act	June 17, 2003	779
108–33	To designate the facility of the United States Postal Service located at 1114 Main Avenue in Clifton, New Jersey, as the "Robert P. Hammer Post Office Building".	June 23, 2003	781
108–34	Zuni Indian Tribe Water Rights Settlement Act of 2003	June 23, 2003	782
108–35	To designate the Federal building and United States courthouse located at 46 East Ohio Street in Indianapolis, Indiana, as the "Birch Bayh Federal Building and United States Courthouse".	June 23, 2003	799
108–36	Keeping Children and Families Safe Act of 2003	June 25, 2003	800
108–37	To designate the regional headquarters building for the National Park Service under construction in Omaha, Nebraska, as the "Carl T. Curtis National Park Service Midwest Regional Headquarters Building".	June 26, 2003	832
108–38	Expressing the sense of Congress with respect to raising awareness and encouraging prevention of sexual assault in the United States and supporting the goals and ideals of National Sexual Assault Awareness and Prevention Month.	June 26, 2003	833
108–39	ORBIT Technical Corrections Act of 2003	June 30, 2003	835
108–40	Welfare Reform Extension Act of 2003	June 30, 2003	836
108–41	Automatic Defibrillation in Adam's Memory Act	July 1, 2003	839
108–42	San Gabriel River Watershed Study Act	July 1, 2003	840
108–43	Glen Canyon National Recreation Area Boundary Revision Act	July 1, 2003	841
108–44	Accountant, Compliance, and Enforcement Staffing Act of 2003	July 3, 2003	842
108–45	Strengthen AmeriCorps Program Act	July 3, 2003	844
108–46	To redesignate the facility of the United States Postal Service located at 7401 West 100th Place in Bridgeview, Illinois, as the "Michael J. Healy Post Office Building".	July 14, 2003	847

Public Law	Title	Approved	117 Stat.
108–47	To designate the facility of the United States Postal Service located at 1830 South Lake Drive in Lexington, South Carolina, as the "Floyd Spence Post Office Building".	July 14, 2003	848
108–48	To redesignate the facility of the United States Postal Service located at 1859 South Ashland Avenue in Chicago, Illinois, as the "Cesar Chavez Post Office".	July 14, 2003	849
108–49	To designate the facility of the United States Postal Service located at 141 Erie Street in Linesville, Pennsylvania, as the "James R. Merry Post Office".	July 14, 2003	850
108–50	To designate the facility of the United States Postal Service located at 111 West Washington Street in Bowling Green, Ohio, as the "Delbert L. Latta Post Office Building".	July 14, 2003	851
108–51	To designate the facility of the United States Postal Service located at 1901 West Evans Street in Florence, South Carolina, as the "Dr. Roswell N. Beck Post Office Building".	July 14, 2003	852
108–52	To designate the facility of the United States Postal Service located at 7554 Pacific Avenue in Stockton, California, as the "Norman D. Shumway Post Office Building".	July 14, 2003	853
108–53	To designate the facility of the United States Postal Service located at 4832 East Highway 27 in Iron Station, North Carolina, as the "General Charles Gabriel Post Office".	July 14, 2003	854
108–54	To designate the facility of the United States Postal Service located at 2318 Woodson Road in St. Louis, Missouri, as the "Timothy Michael Gaffney Post Office Building".	July 14, 2003	855
108–55	To redesignate the facility of the United States Postal Service located at 201 West Boston Street in Brookfield, Missouri, as the "Admiral Donald Davis Post Office Building".	July 14, 2003	856
108–56	To designate the facility of the United States Postal Service located at 1502 East Kiest Boulevard in Dallas, Texas, as the "Dr. Caesar A.W. Clark, Sr. Post Office Building".	July 14, 2003	857
108–57	To designate the facility of the United States Postal Service located at 120 Baldwin Avenue in Paia, Maui, Hawaii, as the "Patsy Takemoto Mink Post Office Building".	July 14, 2003	858
108–58	To authorize the Congressional Hunger Center to award Bill Emerson and Mickey Leland Hunger Fellowships for fiscal years 2003 and 2004.	July 14, 2003	859
108–59	To extend the Abraham Lincoln Bicentennial Commission, and for other purposes	July 14, 2003	860
108–60	To award a congressional gold medal to Prime Minister Tony Blair	July 17, 2003	862
108–61	Burmese Freedom and Democracy Act of 2003	July 28, 2003	864
108–62	To authorize the Secretary of the Interior to grant an easement to facilitate access to the Lewis and Clark Interpretive Center in Nebraska City, Nebraska.	July 29, 2003	871
108–63	To authorize the Secretary of the Interior to acquire the McLoughlin House in Oregon City, Oregon, for inclusion in Fort Vancouver National Historic Site, and for other purposes.	July 29, 2003	872
108–64	To designate the visitor center in Organ Pipe Cactus National Monument in Arizona as the "Kris Eggle Visitor Center", and for other purposes.	July 29, 2003	874
108–65	To redesignate the facility of the United States Postal Service located at 101 South Vine Street in Glenwood, Iowa, as the "William J. Scherle Post Office Building".	July 29, 2003	875
108–66	To provide that certain Bureau of Land Management land shall be held in trust for the Pueblo of Santa Clara and the Pueblo of San Ildefonso in the State of New Mexico.	July 30, 2003	876
108–67	To direct the Secretary of Agriculture to convey certain land in the Lake Tahoe Basin Management Unit, Nevada, to the Secretary of the Interior, in trust for the Washoe Indian Tribe of Nevada and California.	Aug. 1, 2003	880
108–68	To amend the PROTECT Act to clarify certain volunteer liability	Aug. 1, 2003	883
108–69	Emergency Supplemental Appropriations for Disaster Relief Act, 2003	Aug. 8, 2003	885
108–70	To designate the building located at 1 Federal Plaza in New York, New York, as the "James L. Watson United States Court of International Trade Building".	Aug. 14, 2003	886
108–71	To designate the facility of the United States Postal Service located at 9350 East Corporate Hill Drive in Wichita, Kansas, as the "Garner E. Shriver Post Office Building".	Aug. 14, 2003	887
108–72	Smithsonian Facilities Authorization Act	Aug. 15, 2003	888
108–73	Family Farmer Bankruptcy Relief Act of 2003	Aug. 15, 2003	891
108–74	To amend title XXI of the Social Security Act to extend the availability of allotments for fiscal years 1998 through 2001 under the State Children's Health Insurance Program, and for other purposes.	Aug. 15, 2003	892
108–75	Mosquito Abatement for Safety and Health Act	Aug. 15, 2003	898
108–76	Higher Education Relief Opportunities for Students Act of 2003	Aug. 18, 2003	904
108–77	United States-Chile Free Trade Agreement Implementation Act	Sept. 3, 2003	909
108–78	United States-Singapore Free Trade Agreement Implementation Act	Sept. 3, 2003	948
108–79	Prison Rape Elimination Act of 2003	Sept. 4, 2003	972
108–80	To designate the United States courthouse located at 101 North Fifth Street in Muskogee, Oklahoma, as the "Ed Edmondson United States Courthouse".	Sept. 17, 2003	990
108–81	Museum and Library Services Act of 2003	Sept. 25, 2003	991
108–82	To ratify the authority of the Federal Trade Commission to establish a do-not-call registry	Sept. 29, 2003	1006
108–83	Legislative Branch Appropriations Act, 2004	Sept. 30, 2003	1007
108–84	Making continuing appropriations for the fiscal year 2004, and for other purposes	Sept. 30, 2003	1042
108–85	Fremont-Madison Conveyance Act	Sept. 30, 2003	1049
108–86	Postmasters Equity Act of 2003	Sept. 30, 2003	1052
108–87	Department of Defense Appropriations Act, 2004	Sept. 30, 2003	1054
108–88	Surface Transportation Extension Act of 2003	Sept. 30, 2003	1110
108–89	To extend the Temporary Assistance for Needy Families block grant program, and certain tax and trade programs, and for other purposes.	Oct. 1, 2003	1131
108–90	Department of Homeland Security Appropriations Act, 2004	Oct. 1, 2003	1137
108–91	Hospital Mortgage Insurance Act of 2003	Oct. 3, 2003	1158
108–92	To amend chapter 84 of title 5, United States Code, to provide that certain Federal annuity computations are adjusted by 1 percentage point relating to periods of receiving disability payments, and for other purposes.	Oct. 3, 2003	1160
108–93	To direct the Secretary of the Interior to conduct a special resource study to determine the national significance of the Miami Circle site in the State of Florida as well as the suitability and feasibility of its inclusion in the National Park System as part of Biscayne National Park, and for other purposes.	Oct. 3, 2003	1161
108–94	Coltsville Study Act of 2003	Oct. 3, 2003	1163
108–95	Mount Naomi Wilderness Boundary Adjustment Act	Oct. 3, 2003	1165
108–96	Runaway, Homeless, and Missing Children Protection Act	Oct. 10, 2003	1167
108–97	To designate the facility of the United States Postal Service located at 1000 Avenida Sanchez Osorio in Carolina, Puerto Rico, as the "Roberto Clemente Walker Post Office Building".	Oct. 10, 2003	1173

Public Law	Title	Approved	117 Stat.
108–98	To amend the Higher Education Act of 1965 with respect to the qualifications of foreign schools.	Oct. 10, 2003	1174
108–99	To amend the Immigration and Nationality Act to extend for an additional 5 years the special immigrant religious worker program.	Oct. 15, 2003	1176
108–100	Check Clearing for the 21st Century Act	Oct. 28, 2003	1177
108–101	To award a congressional gold medal to Jackie Robinson (posthumously), in recognition of his many contributions to the Nation, and to express the sense of the Congress that there should be a national day in recognition of Jackie Robinson.	Oct. 29, 2003	1195
108–102	To amend title 44, United States Code, to transfer to the Public Printer the authority over the individuals responsible for preparing indexes of the Congressional Record, and for other purposes.	Oct. 29, 2003	1198
108–103	To redesignate the facility of the United States Postal Service located at 48 South Broadway, Nyack, New York, as the "Edward O'Grady, Waverly Brown, Peter Paige Post Office Building".	Oct. 29, 2003	1199
108–104	Making further continuing appropriations for the fiscal year 2004, and for other purposes	Oct. 31, 2003	1200
108–105	Partial-Birth Abortion Ban Act of 2003	Nov. 5, 2003	1201
108–106	Emergency Supplemental Appropriations Act for Defense and for the Reconstruction of Iraq and Afghanistan, 2004.	Nov. 6, 2003	1209
108–107	Making further continuing appropriations for the fiscal year 2004, and for other purposes	Nov. 7, 2003	1240
108–108	Department of the Interior and Related Agencies Appropriations Act, 2004	Nov. 10, 2003	1241
108–109	National Cemetery Expansion Act of 2003	Nov. 11, 2003	1322
108–110	To redesignate the facility of the United States Postal Service located at 120 East Ritchie Avenue in Marceline, Missouri, as the "Walt Disney Post Office Building".	Nov. 11, 2003	1324
108–111	To designate the facility of the United States Postal Service located at 440 South Orange Blossom Trail in Orlando, Florida, as the "Arthur 'Pappy' Kennedy Post Office".	Nov. 11, 2003	1325
108–112	To designate the facility of the United States Postal Service located at 1905 West Blue Heron Boulevard in West Palm Beach, Florida, as the "Judge Edward Rodgers Post Office Building".	Nov. 11, 2003	1326
108–113	To designate the facility of the United States Postal Service located at 1101 Colorado Street in Boulder City, Nevada, as the "Bruce Woodbury Post Office Building".	Nov. 11, 2003	1327
108–114	To designate the facility of the United States Postal Service located at 2300 Redondo Avenue in Long Beach, California, as the "Stephen Horn Post Office Building".	Nov. 11, 2003	1328
108–115	To designate the facility of the United States Postal Service located at 2001 East Willard Street in Philadelphia, Pennsylvania, as the "Robert A. Borski Post Office Building".	Nov. 11, 2003	1329
108–116	To designate the facility of the United States Postal Service located at 1210 Highland Avenue in Duarte, California, as the "Francisco A. Martinez Flores Post Office".	Nov. 11, 2003	1330
108–117	To designate the facility of the United States Postal Service located at 339 Hicksville Road in Bethpage, New York, as the "Brian C. Hickey Post Office Building".	Nov. 11, 2003	1331
108–118	To designate the facility of the United States Postal Service located at 10701 Abercorn Street in Savannah, Georgia, as the "J.C. Lewis, Jr. Post Office Building".	Nov. 11, 2003	1332
108–119	To designate the facility of the United States Postal Service located at 141 Weston Street in Hartford, Connecticut, as the "Barbara B. Kennelly Post Office Building".	Nov. 11, 2003	1333
108–120	To designate the facility of the United States Postal Service located at 135 East Olive Avenue in Burbank, California, as the "Bob Hope Post Office Building".	Nov. 11, 2003	1334
108–121	Military Family Tax Relief Act of 2003	Nov. 11, 2003	1335
108–122	Recognizing the Dr. Samuel D. Harris National Museum of Dentistry, an affiliate of the Smithsonian Institution in Baltimore, Maryland, as the official national museum of dentistry in the United States.	Nov. 11, 2003	1344
108–123	Federal Employee Student Loan Assitance Act	Nov. 11, 2003	1345
108–124	To designate the facility of the United States Postal Service located at 1601-1 Main Street in Jacksonville, Florida, as the "Eddie Mae Steward Post Office".	Nov. 11, 2003	1346
108–125	To extend the authority for the construction of a memorial to Martin Luther King, Jr	Nov. 11, 2003	1347
108–126	To authorize the design and construction of a visitor center for the Vietnam Veterans Memorial.	Nov. 17, 2003	1348
108–127	To amend title XXI of the Social Security Act to make technical corrections with respect to the definition of qualifying State.	Nov. 17, 2003	1354
108–128	Black Canyon of the Gunnison Boundary Revision Act of 2003	Nov. 17, 2003	1355
108–129	To authorize the exchange of lands between an Alaska Native Village Corporation and the Department of the Interior, and for other purposes.	Nov. 17, 2003	1358
108–130	Animal Drug User Fee Act of 2003	Nov. 18, 2003	1361
108–131	Blackwater National Wildlife Refuge Expansion Act	Nov. 22, 2003	1372
108–132	Military Construction Appropriations Act, 2004	Nov. 22, 2003	1374
108–133	District of Columbia Military Retirement Equity Act of 2003	Nov. 22, 2003	1386
108–134	To reauthorize certain school lunch and child nutrition programs through March 31, 2004	Nov. 22, 2003	1389
108–135	Making further continuing appropriations for the fiscal year 2004, and for other purposes	Nov. 22, 2003	1391
108–136	National Defense Authorization Act for Fiscal Year 2004	Nov. 24, 2003	1392
108–137	Energy and Water Development Appropriations Act, 2004	Dec. 1, 2003	1827
108–138	To correct a technical error from Unit T-07 of the John H. Chafee Coastal Barrier Resources System.	Dec. 1, 2003	1869
108–139	Commending the Inspectors General for their efforts to prevent and detect waste, fraud, abuse, and mismanagement, and to promote economy, efficiency, and effectiveness in the Federal Government during the past 25 years.	Dec. 1, 2003	1870
108–140	Recognizing the Agricultural Research Service of the Department of Agriculture for 50 years of outstanding service to the Nation through agricultural research.	Dec. 1, 2003	1872
108–141	To redesignate the facility of the United States Postal Service, located at 315 Empire Boulevard in Crown Heights, Brooklyn, New York, as the "James E. Davis Post Office Building".	Dec. 1, 2003	1874
108–142	Kaloko-Honokohau National Historical Park Addition Act of 2003	Dec. 2, 2003	1875
108–143	To designate the facility of the United States Postal Service located at 710 Wicks Lane in Billings, Montana, as the "Ronald Reagan Post Office Building".	Dec. 2, 2003	1877
108–144	To designate the facility of the United States Postal Service located at 3710 West 73rd Terrace in Prairie Village, Kansas, as the "Senator James B. Pearson Post Office".	Dec. 2, 2003	1878
108–145	Adoption Promotion Act of 2003	Dec. 2, 2003	1879
108–146	Tornado Shelters Act	Dec. 3, 2003	1883

Public Law	Title	Approved	117 Stat.
108–147	Veterans' Compensation Cost-of-Living Adjustment Act of 2003	Dec. 3, 2003	1885
108–148	Healthy Forests Restoration Act of 2003	Dec. 3, 2003	1887
108–149	To designate the facility of the United States Postal Service located at 514 17th Street in Moline, Illinois, as the "David Bybee Post Office Building".	Dec. 3, 2003	1916
108–150	To designate the facility of the United States Postal Service located at 2650 Cleveland Avenue, NW in Canton, Ohio, as the "Richard D. Watkins Post Office Building".	Dec. 3, 2003	1917
108–151	To designate the facility of the United States Postal Service located at 3210 East 10th Street in Bloomington, Indiana, as the "Francis X. McCloskey Post Office Building".	Dec. 3, 2003	1918
108–152	Florida National Forest Land Management Act of 2003	Dec. 3, 2003	1919
108–153	21st Century Nanotechnology Research and Development Act	Dec. 3, 2003	1923
108–154	Birth Defects and Developmental Disabilities Prevention Act of 2003	Dec. 3, 2003	1933
108–155	Pediatric Research Equity Act of 2003	Dec. 3, 2003	1936
108–156	Basic Pilot Program Extension and Expansion Act of 2003	Dec. 3, 2003	1944
108–157	To provide for Federal court proceedings in Plano, Texas	Dec. 3, 2003	1947
108–158	Overseas Private Investment Corporation Amendments Act of 2003	Dec. 3, 2003	1949
108–159	Fair and Accurate Credit Transactions Act of 2003	Dec. 4, 2003	1952
108–160	Environmental Policy and Conflict Resolution Advancement Act of 2003	Dec. 6, 2003	2013
108–161	National Veterinary Medical Service Act	Dec. 6, 2003	2014
108–162	To award a congressional gold medal to Dr. Dorothy Height in recognition of her many contributions to the Nation.	Dec. 6, 2003	2017
108–163	Health Care Safety Net Amendments Technical Corrections Act of 2003	Dec. 6, 2003	2020
108–164	Fairness to Contact Lens Consumers Act	Dec. 6, 2003	2024
108–165	To designate the facility of the United States Postal Service located at 57 Old Tappan Road in Tappan, New York, as the "John G. Dow Post Office Building".	Dec. 6, 2003	2029
108–166	To designate the facility of the United States Postal Service located at 38 Spring Street in Nashua, New Hampshire, as the "Hugh Gregg Post Office Building".	Dec. 6, 2003	2030
108–167	To authorize salary adjustments for Justices and judges of the United States for fiscal year 2004.	Dec. 6, 2003	2031
108–168	National Transportation Safety Board Reauthorization Act of 2003	Dec. 6, 2003	2032
108–169	To reauthorize the United States Fire Administration, and for other purposes	Dec. 6, 2003	2036
108–170	Veterans Health Care, Capital Asset, and Business Improvement Act of 2003	Dec. 6, 2003	2042
108–171	National Flood Insurance Program Reauthorization Act of 2004	Dec. 6, 2003	2064
108–172	To temporarily extend the programs under the Small Business Act and the Small Business Investment Act of 1958 through March 15, 2004, and for other purposes.	Dec. 6, 2003	2065
108–173	Medicare Prescription Drug, Improvement, and Modernization Act of 2003	Dec. 8, 2003	2066
108–174	To reauthorize the ban on undetectable firearms	Dec. 9, 2003	2481
108–175	Syria Accountability and Lebanese Sovereignty Restoration Act of 2003	Dec. 12, 2003	2482
108–176	Vision 100-Century of Aviation Reauthorization Act	Dec. 12, 2003	2490
108–177	Intelligence Authorization Act for Fiscal Year 2004	Dec. 13, 2003	2599
108–178	To improve the United States Code	Dec. 15, 2003	2637
108–179	Torture Victims Relief Reauthorization Act of 2003	Dec. 15, 2003	2643
108–180	To award congressional gold medals posthumously on behalf of Reverend Joseph A. DeLaine, Harry and Eliza Briggs, and Levi Pearson in recognition of their contributions to the Nation as pioneers in the effort to desegregate public schools that led directly to the landmark desegregation case of Brown et al. v. the Board of Education of Topeka et al.	Dec. 15, 2003	2645
108–181	Appointing the day for the convening of the second session of the One Hundred Eighth Congress.	Dec. 15, 2003	2648
108–182	Hometown Heroes Survivors Benefits Act of 2003	Dec. 15, 2003	2649
108–183	Veterans Benefits Act of 2003	Dec. 16, 2003	2651
108–184	National Museum of African American History and Culture Act	Dec. 16, 2003	2676
108–185	Making further continuing appropriations for the fiscal year 2004, and for other purposes	Dec. 16, 2003	2684
108–186	To support certain housing proposals in the fiscal year 2003 budget for the Federal Government, including the downpayment assistance initiative under the HOME Investment Partnership Act, and for other purposes.	Dec. 16, 2003	2685
108–187	Controlling the Assault of Non-Solicited Pornography and Marketing Act of 2003	Dec. 16, 2003	2699
108–188	Compact of Free Association Amendments Act of 2003	Dec. 17, 2003	2720
108–189	To restate, clarify, and revise the Soldiers' and Sailors' Civil Relief Act of 1940	Dec. 19, 2003	2835
108–190	To provide for the exchange of certain lands in the Coconino and Tonto National Forests in Arizona, and for other purposes.	Dec. 19, 2003	2867
108–191	Captive Wildlife Safety Act	Dec. 19, 2003	2871
108–192	Carter G. Woodson Home National Historic Site Act	Dec. 19, 2003	2873
108–193	Trafficking Victims Protection Reauthorization Act of 2003	Dec. 19, 2003	2875
108–194	Poison Control Center Enhancement and Awareness Act Amendments of 2003	Dec. 19, 2003	2888
108–195	Defense Production Act Reauthorization of 2003	Dec. 19, 2003	2892
108–196	Federal Law Enforcement Pay and Benefits Parity Act of 2003	Dec. 19, 2003	2896
108–197	Mental Health Parity Reauthorization Act of 2003	Dec. 19, 2003	2898
108–198	Preserving Independence of Financial Institution Examinations Act of 2003	Dec. 19, 2003	2899

NATIONAL ARCHIVES AND RECORDS ADMINISTRATION
LITTERA SCRIPTA MANET
1985

Federal Register

Friday,
January 30, 2004

Part III

Environmental Protection Agency

40 CFR Parts 51, 72, 75, and 96

Rule To Reduce Interstate Transport of Fine Particulate Matter and Ozone (Interstate Air Quality Rule); Proposed Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 51, 72, 75, and 96

[FRL–7604–3]

Rule To Reduce Interstate Transport of Fine Particulate Matter and Ozone (Interstate Air Quality Rule)

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: In today's action, EPA is proposing to find that 29 States and the District of Columbia contribute significantly to nonattainment of the national ambient air quality standards (NAAQS) for fine particles ($PM_{2.5}$) and/or 8-hour ozone in downwind States. The EPA is proposing to require these upwind States to revise their State implementation plans (SIPs) to include control measures to reduce emissions of sulfur dioxide (SO_2) and/or nitrogen oxides (NO_X). Sulfur dioxide is a precursor to $PM_{2.5}$ formation, and NO_X is a precursor to both ozone and $PM_{2.5}$ formation. Reducing upwind precursor emissions will assist the downwind $PM_{2.5}$ and 8-hour ozone nonattainment areas in achieving the NAAQS. Moreover, attainment would be achieved in a more equitable, cost-effective manner than if each nonattainment area attempted to achieve attainment by implementing local emissions reductions alone.

Based on State obligations to address interstate transport of pollutants under section 110(a)(2)(D) of the Clean Air Act (CAA), EPA is proposing statewide emissions reduction requirements for SO_2 and NO_X. The EPA is proposing that the emissions reductions be implemented in two phases, with the first phase in 2010 and the second phase in 2015. The proposed emissions reduction requirements are based on controls that are known to be highly cost effective for electric generating units (EGUs).

Today's action also discusses model multi-State cap and trade programs for SO_2 and NO_X that States could choose to adopt to meet the proposed emissions reductions in a flexible and cost-effective manner. The EPA intends to propose the model trading programs in a future supplemental action.

DATES: The comment period on this proposal ends on March 30, 2004. Comments must be postmarked by the last day of the comment period and sent directly to the Docket Office listed in **ADDRESSES** (in duplicate form if possible).

Up to two public hearings will be held prior to the end of the comment period. The dates, times and locations will be announced separately. Please refer to **SUPPLEMENTARY INFORMATION** for additional information on the comment period and public hearings.

ADDRESSES: Comments may be submitted by mail to: Air Docket, Environmental Protection Agency, Mail code: 6102T, 1200 Pennsylvania Ave., NW., Washington, DC 20460, Attention Docket ID No. OAR–2003–0053.

Comments may also be submitted electronically, by facsimile, or through hand delivery/courier. Follow the detailed instructions provided under **SUPPLEMENTARY INFORMATION**.

Documents relevant to this action are available for public inspection at the EPA Docket Center, located at 1301 Constitution Avenue, NW., Room B102, Washington, DC between 8:30 a.m. and 4:30 p.m., Monday through Friday, excluding legal holidays. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: For general questions concerning today's action, please contact Scott Mathias, U.S. EPA, Office of Air Quality Planning and Standards, Air Quality Strategies and Standards Division, C539–01, Research Triangle Park, NC, 27711, telephone (919) 541–5310, e-mail at *mathias.scott@epa.gov*. For legal questions, please contact Howard J. Hoffman, U.S. EPA, Office of General Counsel, Mail Code 2344A, 1200 Pennsylvania Avenue, NW., Washington, DC, 20460, telephone (202) 564–5582, e-mail at *hoffman.howard@epa.gov*. For questions regarding air quality analyses, please contact Norm Possiel, U.S. EPA, Office of Air Quality Planning and Standards, Emissions Modeling and Analysis Division, D243–01, Research Triangle Park, NC, 27711, telephone (919) 541–5692, e-mail at *possiel.norm@epa.gov*. For questions regarding statewide emissions inventories and emissions reductions requirements, please contact Ron Ryan, U.S. EPA, Office of Air Quality Planning and Standards, Emissions Modeling and Analysis Division, Mail Code D205–01, Research Triangle Park, NC, 27711, telephone (919) 541–4330, e-mail at *ryan.ron@epa.gov*. For questions regarding the EGU cost analyses, emissions inventories and budgets, please contact Kevin Culligan, U.S. EPA, Office of Atmospheric Programs, Clean Air Markets Division, Mail Code 6204J, 1200 Pennsylvania Avenue, NW., Washington, DC, 20460, telephone (202) 343–9172, e-mail at *culligan.kevin@epa.gov*. For questions regarding the model cap and trade programs, please contact Sam Waltzer, U.S. EPA, Office of Atmospheric Programs, Clean Air Markets Division, Mail Code 6204J, 1200 Pennsylvania Avenue, NW., Washington, DC, 20460, telephone (202) 343–9175, e-mail at *waltzer.sam@epa.gov*. For questions regarding the regulatory impact analyses, please contact Linda Chappell, U.S. EPA, Office of Air Quality Planning and Standards, Air Quality Strategies and Standards Division, Mail Code C339–01, Research Triangle Park, NC, 27711, telephone (919) 541–2864, e-mail at *chappell.linda@epa.gov*.

SUPPLEMENTARY INFORMATION:

Regulated Entities

This action does not propose to directly regulate emissions sources. Instead, it proposes to require States to revise their SIPs to include control measures to reduce emissions of NO_X and SO_2. The proposed emissions reductions requirements that would be assigned to the States are based on controls that are known to be highly cost effective for EGUs.

Public Hearing

The EPA will hold up to two public hearings on today's proposal during the comment period. The details of the public hearings, including the times, dates, and locations will be provided in a future **Federal Register** notice and announced on EPA's Web site for this rulemaking at *http://www.epa.gov/interstateairquality/*.

The public hearings will provide interested parties the opportunity to present data, views, or arguments concerning the proposed rule. The EPA may ask clarifying questions during the oral presentations, but will not respond to the presentations or comments at that time. Written statements and supporting information submitted during the comment period will be considered with the same weight as any oral comments and supporting information presented at a public hearing.

How Can I Get Copies of This Document and Other Related Information?

Docket. The EPA has established an official public docket for this action under Docket ID No. OAR–2003–0053. The official public docket consists of the documents specifically referenced in this action, any public comments received, and other information related to this action. Although a part of the official docket, the public docket does not include Confidential Business Information (CBI) or other information whose disclosure is restricted by statute.

The official public docket is the collection of materials that is available for public viewing at the Air Docket in the EPA Docket Center, (EPA/DC) EPA West, Room B102, 1301 Constitution Ave., NW., Washington, DC. The EPA Docket Center Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742. A reasonable fee may be charged for copying.

Electronic Access. You may access this **Federal Register** document electronically through the EPA Internet under the "**Federal Register**" listings at *http://www.epa.gov/fedrgstr/.*

An electronic version of the public docket is available through EPA's electronic public docket and comment system, EPA Dockets. You may use EPA Dockets at *http://www.epa.gov/edocket/* to submit or view public comments, access the index listing of the contents of the official public docket, and to access those documents in the public docket that are available electronically. Once in the system, select "search," then key in the appropriate docket identification number.

Certain types of information will not be placed in the EPA Dockets. Information claimed as CBI and other information whose disclosure is restricted by statute, which is not included in the official public docket, will not be available for public viewing in EPA's electronic public docket. The EPA's policy is that copyrighted material will not be placed in EPA's electronic public docket but will be available only in printed, paper form in the official public docket. To the extent feasible, publicly available docket materials will be made available in EPA's electronic public docket. When a document is selected from the index list in EPA Dockets, the system will identify whether the document is available for viewing in EPA's electronic public docket. Although not all docket materials may be available electronically, you may still access any of the publicly available docket materials through the docket facility identified above. The EPA intends to work towards providing electronic access to all of the publicly available docket materials through EPA's electronic public docket.

For public commenters, it is important to note that EPA's policy is that public comments, whether submitted electronically or in paper, will be made available for public viewing in EPA's electronic public docket as EPA receives them and without change, unless the comment contains copyrighted material, CBI, or other information whose disclosure is restricted by statute. When EPA identifies a comment containing copyrighted material, EPA will provide a reference to that material in the version of the comment that is placed in EPA's electronic public docket. The entire printed comment, including the copyrighted material, will be available in the public docket.

Public comments submitted on computer disks that are mailed or delivered to the docket will be transferred to EPA's electronic public docket. Public comments that are mailed or delivered to the Docket will be scanned and placed in EPA's electronic public docket. Where practical, physical objects will be photographed, and the photograph will be placed in EPA's electronic public docket along with a brief description written by the docket staff.

For additional information about EPA's electronic public docket, visit EPA Dockets online or *see* 67 FR 38102; May 31, 2002.

The EPA has also established a Web site for this rulemaking at *http://www.epa.gov/interstateairquality/* which will include the rulemaking actions and certain other related information.

How and to Whom Do I Submit Comments?

You may submit comments electronically, by mail, by facsimile, or through hand delivery/courier. To ensure proper receipt by EPA, identify the appropriate docket identification number, OAR–2003–0053, in the subject line on the first page of your comment. Please ensure that your comments are submitted within the specified comment period. Comments received after the close of the comment period will be marked "late." The EPA is not required to consider these late comments. If you wish to submit CBI or information that is otherwise protected by statute, please follow the instructions below under, "How Should I submit CBI to the Agency?" Do not use EPA Dockets or e-mail to submit CBI or information protected by statute.

Electronically. If you submit an electronic comment as prescribed below, EPA recommends that you include your name, mailing address, and an e-mail address or other contact information in the body of your comment. Also include this contact information on the outside of any disk or CD ROM you submit, and in any cover letter accompanying the disk or CD ROM. This ensures that you can be identified as the submitter of the comment and allows EPA to contact you in case EPA cannot read your comment due to technical difficulties or needs further information on the substance of your comment. The EPA's policy is that EPA will not edit your comment, and any identifying or contact information provided in the body of a comment will be included as part of the comment that is placed in the official public docket, and made available in EPA's electronic public docket. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment.

EPA Dockets. Your use of EPA's electronic public docket to submit comments to EPA electronically is EPA's preferred method for receiving comments. Go directly to EPA Dockets at *http://www.epa.gov/edocket,* and follow the online instructions for submitting comments. To access EPA's electronic public docket from the EPA Internet Home Page, select "Information Sources," "Dockets," and "EPA Dockets." Once in the system, select "search," and then key in Docket ID No. OAR–2003–0053. The system is an "anonymous access" system, which means EPA will not know your identity, e-mail address, or other contact information unless you provide it in the body of your comment.

Electronic mail. Comments may be sent by e-mail to *A-and-R-Docket@epa.gov,* Attention Docket ID No. OAR–2003–0053. In contrast to EPA's electronic public docket, EPA's e-mail system is not an "anonymous access" system. If you send an e-mail comment directly to the Docket without going through EPA's electronic public docket, EPA's e-mail system automatically captures your e-mail address. The e-mail addresses that are automatically captured by EPA's e-mail system are included as part of the comment that is placed in the official public docket, and made available in EPA's electronic public docket. Electronic submissions will be accepted in WordPerfect or ASCII file format. Avoid the use of special characters and any form of encryption.

Disk or CD ROM. You may submit comments on a disk or CD ROM that you mail to the mailing address identified under Docket above. These electronic submissions will be accepted in WordPerfect or ASCII file format. Avoid the use of special characters and any form of encryption.

By Mail. Send your comments to Air Docket (in duplicate if possible), Environmental Protection Agency, Mail code: 6102T, 1200 Pennsylvania Ave., NW, Washington, DC, 20460, Attention Docket ID No. OAR–2003–0053.

By Hand Delivery or Courier. Deliver your comments to: Air Docket, Environmental Protection Agency, 1301 Constitution Avenue, NW, Room B108, Mail code: 6102T, Washington, DC 20004, Attention Docket ID No. OAR–2003–0053. Such deliveries are only accepted during the Docket's normal hours of operation as identified above under Docket.

By Facsimile. Fax your comments to (202) 566–1741, Attention Docket ID. No. OAR–2003–0053.

How Should I Submit CBI to the Agency?

Do not submit information that you consider to be CBI electronically through EPA's electronic public docket or by e-mail. Send or deliver information identified as CBI only to the following address: Roberto Morales, U.S. EPA, Office of Air Quality Planning and Standards, Mail Code C404–02, Research Triangle Park, NC 27711, telephone (919) 541–0880, e-mail at *morales.roberto@epa.gov,* Attention Docket ID No. OAR–2003–0053. You may claim information that you submit to EPA as CBI by marking any part or all of that information as CBI (if you submit CBI on disk or CD ROM, mark the outside of the disk or CD ROM as CBI and then identify electronically within the disk or CD ROM the specific information that is CBI). Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

In addition to one complete version of the comment that includes any information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket and EPA's electronic public docket. If you submit the copy that does not contain CBI on disk or CD ROM, mark the outside of the disk or CD ROM clearly that it does not contain CBI. Information not marked as CBI will be included in the public docket and EPA's electronic public docket without prior notice. If you have any questions about CBI or the procedures for claiming CBI, please consult the person identified in the FOR FURTHER INFORMATION CONTACT section.

What Should I Consider as 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.
2. Describe any assumptions that you used.
3. Provide 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 your estimate.
5. Provide specific examples to illustrate your concerns.
6. Offer alternatives.
7. Make sure to submit your comments by the comment period deadline identified.
8. To ensure proper receipt by EPA, identify the appropriate docket identification number in the subject line on the first page of your response. It would also be helpful if you provided the name, date, and **Federal Register** citation related to your comments.

Outline

I. Background

A. Summary of Rulemaking and Affected States

The CAA contains a number of requirements to address nonattainment of the $PM_{2.5}$ and the 8-hour ozone national ambient air quality standards (NAAQS), including requirements that States address interstate transport that contributes to such nonattainment.[1] Based on air quality modeling, ambient air quality data analyses, and cost analyses, EPA proposes to conclude that emissions in certain upwind States result in amounts of transported fine particles ($PM_{2.5}$), ozone, and their emissions precursors that significantly contribute to nonattainment in downwind States. In today's action, we are proposing State implementation plan (SIP) requirements for the affected upwind States under CAA section 110(a)(1) to meet the requirements of section 110(a)(2)(D). Clean Air Act Section 110(a)(2)(D) requires SIPs to contain adequate provisions to prohibit air pollutant emissions from sources or activities in those States from "contribut[ing] significantly to nonattainment in," a downwind State of the $PM_{2.5}$ and ozone NAAQS. In particular, EPA is proposing to require SIP revisions in 29 States and the District of Columbia to ensure that SIPs provide for necessary regional reductions of emissions of SO_2 and/or NO_X, which are important precursors of $PM_{2.5}$ (NO_X and SO_2) and ozone (NO_X). Achieving these emissions reductions will help enable $PM_{2.5}$ and ozone nonattainment areas in the eastern half of the United States to prepare attainment demonstrations. Moreover, attainment would ultimately be achieved in a more certain, equitable, and cost-effective manner than if each nonattainment area attempted to implement local emissions reductions alone. We are proposing to require the submission of SIP measures that meet the specified SO_2 and NO_X emissions reductions requirements within 18 months after publication of the notice of final rulemaking.

The EPA has evaluated current scientific and technical knowledge and conducted a number of air quality data and modeling analyses regarding the contribution of pollutant emissions to interstate transport. These evaluations and modeling analyses are summarized in section II, Characterization of the Origin and Distribution of 8-Hour Ozone and $PM_{2.5}$ Air Quality Problems, section IV, Air Quality Modeling to Determine Future 8-Hour Ozone and $PM_{2.5}$ Concentrations, and section V, Air Quality Aspects of Significant Contribution for 8-Hour Ozone and Annual Average $PM_{2.5}$ Before Considering Cost. The EPA proposes to find, after considering relevant information, that SO_2 and NO_X emissions in the District of Columbia and the following 28 States significantly contribute to nonattainment in a downwind State with respect to the $PM_{2.5}$ NAAQS: Alabama, Arkansas, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, and Wisconsin. The EPA also proposes to find, after considering relevant information, that NO_X emissions in the District of Columbia and the following 25 States significantly contribute to nonattainment in a downwind State with respect to the 8-hour ozone NAAQS: Alabama, Arkansas, Connecticut, Delaware, Georgia, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin. In addition to proposing findings of significant contribution to nonattainment, EPA is proposing to assign emissions reductions requirements for SO_2 and/or NO_X that each of the identified States must meet through SIP measures.

The proposed emissions reductions requirements are based on controls that EPA has determined to be highly cost effective for EGUs under an optional cap and trade program. However, States have the flexibility to choose the measures to adopt to achieve the specified emissions reductions. If the State chooses to control EGUs, then it must establish a budget—that is, an emissions cap—for those sources. Due to feasibility constraints, EPA is proposing that the emissions reductions be implemented in two phases, with the first phase in 2010 and the second phase in 2015. These requirements are described in more detail in section VI, Emissions Control Requirements; section VII, State Implementation Plan Schedules and Requirements; and section VIII, Model Cap and Trade Program.

Section VIII discusses model multi-State cap and trade programs for SO_2 and NO_X that EPA is developing that States could choose to adopt to meet the proposed emissions reductions in a flexible and cost-effective way. We intend to propose the model trading programs in a future supplemental notice of proposed rulemaking (SNPR) to be issued by May 2004. We plan to address several additional issues in the SNPR.

Sulfur dioxide and NO_X are not the only emissions that contribute to interstate transport and $PM_{2.5}$ nonattainment. However, EPA believes that given current knowledge, it is not appropriate at this time to specify emissions reduction requirements for direct $PM_{2.5}$ emissions or organic precursors (*e.g.* volatile organic compounds (VOCs) or ammonia (NH_3)). (For further discussion of EPA's proposal on which pollutant emissions to regulate, see section III.) Therefore, we are not proposing new SIP requirements for emissions of these pollutants for the purpose of reducing the interstate transport of $PM_{2.5}$. States may, however, need to consider additional reductions in some or all of these emissions as they develop SIPs to attain and maintain the $PM_{2.5}$ standards. Similarly, for 8-hour ozone, we continue to rely on the conclusion of the Ozone Transport Assessment Group (OTAG) that analysis of interstate transport control opportunities should focus on NO_X, rather than VOCs.[2]

Section III of this preamble, Overview of Proposed Interstate Air Quality Rule, explains in broad overview our assessment of the interstate pollution transport problem and our development of this proposal to address transport under the CAA.

The requirements in this proposal are intended to address regional interstate transport of air pollution. There are likely more localized transport problems that will remain, particularly between contiguous urban areas located in two or more States. States that share an interstate nonattainment area are expected to work together in developing the nonattainment SIP for that area, reducing emissions that contribute to local-scale interstate transport problems.

In this preamble, we generally refer to States as both the sources and receptors of interstate transport that contributes to nonattainment. We intend to refer to Tribal governments in a similar way. Clean Air Act section 301(d) recognizes that American Indian Tribal

[1] In today's proposal, when we use the term "transport" we mean to include the transport of both fine particles ($PM_{2.5}$) and their precursor emissions and/or transport of both ozone and its precursor emissions.

[2] The OTAG was active from 1995–1997 and consisted of representatives from the 37 states in that region; the District of Columbia; EPA; and interested members of the public, including industry and environmental groups. See discussion below under NO_X SIP Call for further information on OTAG.

governments are generally the appropriate authority to implement the CAA in Indian country. The Tribal Authority Rule (TAR) (63 FR 7262; February 12, 1998 and 59 FR 43960–43961; August 24, 1994) discusses the provisions of the CAA for which it is appropriate to treat Tribes in a manner similar to States. Therefore, in this preamble, unless otherwise specified, when we discuss the role of the State in implementing the Interstate Air Quality Rule, we are also referring to the Tribes. In certain parts of this preamble, however, we ask for comments on addressing the special needs of the Tribes. Section VI provides a more complete discussion of this Tribal issue.

Our benefit-cost analysis concludes that substantial net economic benefits to society are likely to be achieved as a result of the emissions reductions associated with this rulemaking. The results detailed in section XI show that this rule would be highly beneficial to society, with annual net benefits by 2010 of approximately $55 billion ($58 billion annual benefits compared to annual social cost of approximately $3 billion) and net annual benefits by 2015 of $80 billion ($84 billion in benefits compared to annual social costs of $4 billion). Therefore, even if the benefits were overestimated by as much as a factor of twenty, benefits would still exceed costs.

B. General Background on Air Quality Impacts of $PM_{2.5}$ and Ozone

1. What Are the Effects of Ambient $PM_{2.5}$?

On July 18, 1997, we revised the NAAQS for particulate matter (PM) to add new standards for fine particles, using as the indicator particles with aerodynamic diameters smaller than a nominal 2.5 micrometers, termed $PM_{2.5}$. We established health- and welfare-based (primary and secondary) annual and 24-hour standards for $PM_{2.5}$ (62 FR 38652). The annual standards are 15 micrograms per cubic meter, based on the 3-year average of annual mean $PM_{2.5}$ concentrations. The 24-hour standard is a level of 65 micrograms per cubic meter, based on the 3-year average of the annual 98th percentile of 24-hour concentrations.

Fine particles are associated with a number of serious health effects including premature mortality, aggravation of respiratory and cardiovascular disease (as indicated by increased hospital admissions, emergency room visits, absences from school or work, and restricted activity days), lung disease, decreased lung function, asthma attacks, and certain cardiovascular problems such as heart attacks and cardiac arrhythmia. The EPA has estimated that attainment of the $PM_{2.5}$ standards would prolong tens of thousands of lives and prevent tens of thousands of hospital admissions each year, as well as hundreds of thousands of doctor visits, absences from work and school, and respiratory illnesses in children. Individuals particularly sensitive to fine particle exposure include older adults, people with heart and lung disease, and children. Health studies have shown that there is no clear threshold below which adverse effects are not experienced by at least certain segments of the population. Thus, some individuals particularly sensitive to fine particle exposure may be adversely affected by fine particle concentrations below those for the annual and 24-hour standards. More detailed information on health effects of fine particles can be found on EPA's Web site at: *http://www.epa.gov/ttn/naaqs/standards/pm/s_pm_index.html.*

At the time EPA established the primary standards in 1997, we also established welfare-based (secondary) standards identical to the primary standards. The secondary standards are designed to protect against major environmental effects caused by PM such as visibility impairment, soiling, and materials damage.

The EPA also established the regional haze regulations in 1999 for the improvement of visual air quality in Class I areas which include national parks and wilderness areas across the country.

As discussed in other sections of this preamble, EGUs are a major source of SO_2 and NO_X emissions, both of which contribute to fine particle concentrations. In addition, EGU NO_X emissions contribute to ozone problems, described in the next section. We believe today's proposal will significantly reduce SO_2 and NO_X emissions that contribute to $PM_{2.5}$ and 8-hour ozone problems described here. The control strategies we are proposing are discussed in detail in section III and section VI below.

2. What Are the Effects of Ambient Ozone?

On July 18, 1997, EPA promulgated identical revised ozone primary and secondary ozone standards that specified that the 3-year average of the fourth highest daily maximum 8-hour average ozone concentration could not exceed 0.08 ppm. In general, the revised 8-hour standards are more protective of public health and the environment and more stringent than the pre-existing 1-hour ozone standards. There are more areas that do not meet the 8-hour standard than there are that do not meet the 1-hour standard. Short-term (1- to 3-hour) and prolonged (6- to 8-hour) exposures to ambient ozone have been linked to a number of adverse health effects. Short-term exposure to ozone can irritate the respiratory system, causing coughing, throat irritation, and chest pain. Ozone can reduce lung function and make it more difficult to breathe deeply. Breathing may become more rapid and shallow than normal, thereby limiting a person's normal activity. Ozone also can aggravate asthma, leading to more asthma attacks that require a doctor's attention and the use of additional medication. Increased hospital admissions and emergency room visits for respiratory problems have been associated with ambient ozone exposures. Longer-term ozone exposure can inflame and damage the lining of the lungs, which may lead to permanent changes in lung tissue and irreversible reductions in lung function. A lower quality of life may result if the inflammation occurs repeatedly over a long time period (such as months, years, a lifetime).

People who are particularly susceptible to the effects of ozone include children and adults who are active outdoors, people with respiratory diseases, such as asthma, and people with unusual sensitivity to ozone.

In addition to causing adverse health effects, ozone affects vegetation and ecosystems, leading to reductions in agricultural crop and commercial forest yields; reduced growth and survivability of tree seedlings; and increased plant susceptibility to disease, pests, and other environmental stresses (*e.g.*, harsh weather). In long-lived species, these effects may become evident only after several years or even decades and thus have the potential for long-term adverse impacts on forest ecosystems. Ground-level ozone damage to the foliage of trees and other plants can also decrease the aesthetic value of ornamental species used in residential landscaping, as well as the natural beauty of our national parks and recreation areas. The economic value of some welfare losses due to ozone can be calculated, such as crop yield loss from both reduced seed production (*e.g.*, soybean) and visible injury to some leaf crops (*e.g.*, lettuce, spinach, tobacco) and visible injury to ornamental plants (*i.e.*, grass, flowers, shrubs), while other types of welfare loss may not be fully quantifiable in economic terms (*e.g.*, reduced aesthetic value of trees growing in heavily visited National parks). More detailed information on health effects of ozone can be found at the following EPA Web site: *http://www.epa.gov/ttn/naaqs/standards/ozone/s_o3_index.html.*

3. What Other Environmental Effects Are Associated With SO_2 and NO_X, the Main Precursors to $PM_{2.5}$ and Ozone Addressed in This Proposal?

This proposed action will result in benefits in addition to the enumerated human health and welfare benefits resulting from reductions in ambient levels of PM and ozone. Reductions in NO_X and SO_2 will contribute to substantial visibility improvements in many parts of the Eastern U.S. where people live, work, and recreate, including Federal Class I areas such as the Great Smoky Mountains. Reductions in these pollutants will also reduce acidification and eutrophication of water bodies in the region. In addition, reduced mercury emissions are anticipated as a result of this proposal. Reduced mercury emissions will lessen mercury contamination in lakes and thereby potentially decrease both human and wildlife exposure.

C. What Is the Ambient Air Quality of $PM_{2.5}$ and Ozone?

1. What Is the $PM_{2.5}$ Ambient Air Quality?

The $PM_{2.5}$ ambient air quality monitoring for the 2000–2002 period shows that areas violating the standards are located across much of the eastern half of the United States and in parts of California. Based on these data, 120 counties have at least one monitor that violates either the annual or the 24-hour $PM_{2.5}$ standard. Most areas violate only the annual standard; a small number of areas violate both the annual and 24-hour standards; and no areas violate just the 24-hour standard. The population of these 120 counties totals 65 million people.

Only two States in the western half of the U.S., California and Montana, have counties that exceed the $PM_{2.5}$ standards. On the other hand, in the eastern half of the U.S., 175 sites in 106 counties exceeded the annual $PM_{2.5}$ standard of 15.0 micrograms per cubic meter ($\mu g/m^3$) over the 3-year period from 2000 to 2002 and 395 sites meet the annual standard. No sites in the eastern half of the United States exceed the daily $PM_{2.5}$ standard of 65 $\mu g/m^3$. The 106 violating counties are located in a distinct region made up of 19 States (plus the District of Columbia), extending from St. Clair County, Illinois (East St. Louis), the western-most violating county, to New Haven, Connecticut, the eastern-most violating county, and including the following States located in between: Illinois, Michigan, Indiana, Ohio, Pennsylvania, New York, New Jersey, Kentucky, West Virginia, Virginia, Maryland, Delaware, Tennessee, North Carolina, Alabama, Georgia, and South Carolina.

Because interstate transport is not thought to be a main contributor to exceedances of the $PM_{2.5}$ standards in California or Montana, today's proposal is focused only on the $PM_{2.5}$ monitoring sites in the Eastern U.S.

Speciated ambient data, which measures the major components of $PM_{2.5}$ (sulfate, nitrate, total carbonaceous mass, and crustal material) are invaluable in understanding the nature and extent of the $PM_{2.5}$ problem. Speciated data from the Interagency Monitoring of Protected Visual Environments (IMPROVE), the Clean Air Status and Trends Network (CASTNET), both predominantly rural networks, along with EPA's Speciation Network, show that ambient concentrations of $PM_{2.5}$ species have distinctive seasonal and geographic patterns within the eastern United States.

Mass associated with ammonium sulfate concentrations make up a significant portion (25 to 50 percent) of the annual average $PM_{2.5}$ mass. The largest sulfate contributions to $PM_{2.5}$ mass occur during the summer season mainly within a large multi-State area centered near Tennessee and Southwest Virginia. Sulfate concentrations during the winter season are relatively low.

Concentrations of ammonium nitrate particles typically comprise less than 25 percent of the annual average $PM_{2.5}$ mass. Nitrates tend to be highest during the winter months over large portions of the Midwest including northern Ohio, Indiana, Michigan, and eastern Wisconsin. Relatively higher winter concentrations are also reported within and near major urban areas including metropolitan New York, Philadelphia, and the Baltimore-Washington, DC area. Nitrate concentrations reported in southern States represent a somewhat smaller portion of the $PM_{2.5}$ mass, primarily due to warmer temperatures that are less conducive to nitrate formation and chemical stability.

Total carbon also contributes a significant amount of mass to annual $PM_{2.5}$ levels (25 to 50 percent) but does not exhibit strong seasonal or regional concentration patterns. As with nitrate, total carbon concentrations are higher in and near urban areas.

Concentrations of the last $PM_{2.5}$ component, crustal, are relatively small (less than 10 percent of $PM_{2.5}$ mass) and do not exhibit strong regional or seasonal trends. (For further discussion on the science of $PM_{2.5}$ formation, see section II; for further discussion of EPA's proposal on which pollutant emissions to regulate, see section III.)

2. What Is the Ozone Ambient Air Quality?

Almost all areas of the country have experienced some progress in lowering ozone concentrations over the last 20 years. As reported in the EPA's report, "Latest Findings on National Air Quality: 2002 Status and Trends," [3] national average levels of 1-hour ozone improved by 22 percent between 1983 and 2002 while 8-hour levels improved by 14 percent over the same time period. The Northeast and Pacific Southwest (particularly Los Angeles) have shown the greatest 20-year improvement. Even so, on balance, ozone has exhibited the slowest progress of the six major pollutants tracked nationally. During the most recent 10 years, ozone levels have been relatively constant reflecting little if any air quality improvement. During the period from 1993 to 2002, additional control requirements have reduced emissions of the two major ozone precursors, although at different rates. Emissions of VOCs were reduced by 25 percent from 1993 levels, while emissions of NO_X declined by only 11 percent. During the same time period, gross domestic product increased by 57 percent and vehicle miles traveled increased by 23 percent.

Despite the progress made nationally since 1970, ozone remains a significant public health concern. Presently, wide geographic areas, including most of the nation's major population centers, experience unhealthy ozone levels—concentrations exceeding the NAAQS for 8-hour ozone. These areas include much of the eastern half of the United States and large areas of California. More specifically, 297 counties with a total population of over 115 million people currently violate the 8-hour ozone standard.

Existing regulatory requirements (*e.g.*, Federal motor vehicle standards, EPA's regional NO_X rule known as the NO_X SIP Call, and local measures already adopted under the CAA) are expected to reduce over time the geographic extent of the nation's 8-hour ozone problem. However, the number of people living in areas with unhealthy ozone levels will remain significant for the foreseeable future because existing control programs alone will not eliminate unhealthy ozone levels in some of the nation's largest population centers.

[3] EPA 454/K–03–001, August 2003.

D. What Is the Statutory and Regulatory Background for Today's Action?

1. What are the CAA Provisions on Attainment of the $PM_{2.5}$ and Ozone NAAQS?

The CAA, which was extensively amended by Congress in 1990, contains numerous State planning and attainment requirements associated with the PM and ozone NAAQS. In 1997, EPA revised the NAAQS for PM to add new annual average and 24–hour standards for fine particles, using $PM_{2.5}$ as the indicator (62 FR 38652). At the same time, EPA issued its final action to revise the NAAQS for ozone (62 FR 38856) to establish new 8–hour standards. These standards were subject to litigation, which delayed implementation. The litigation was sufficiently resolved in 2001 to permit the EPA and States to begin the process of implementing the new $PM_{2.5}$ and 8–hour ozone standards. *See Whitman* v. *American Trucking Ass'n.*, 121 S.Ct. 903 (2001).

Following promulgation of new NAAQS, the CAA requires all areas, regardless of their designation as attainment, nonattainment, or unclassifiable, to submit SIPs containing provisions specified under section 110(a)(2). This includes provisions to address the following required SIP elements: emission limits and other control measures; provisions for meeting nonattainment requirements; ambient air quality monitoring/data system; program for enforcement of control measures; measures to address interstate transport; provisions for adequate funding, personnel, and legal authority for implementing the SIP; stationary source monitoring system; authority to implement the emergency episode provisions in their SIPs; provisions for SIP revision due to NAAQS changes or findings of inadequacy; consultation requirements with local governments and land managers; requirement to meet applicable requirements of part C related to prevention of significant deterioration and visibility protection; air quality modeling/data; stationary source permitting fees; and provisions for consultation and participation by affected local entities affected by the SIP. In addition, SIPs for nonattainment areas are generally required to include additional emissions controls providing for attainment of the NAAQS.

Under subpart 1 of part D, the SIPs must include, but are not limited to, the following elements: (1) Reasonably available control measures (RACM) and reasonably available control technology (RACT) control measures, (2) measures to assure reasonable further progress (RFP), (3) an accurate and comprehensive inventory of actual emissions for all sources of the relevant pollutant in the nonattainment area, (4) enforceable emissions limits for stationary sources, (5) permits for new and modified major stationary sources, (6) measures for new source review (NSR), and (7) contingency measures which should be ready to be implemented without further action from the State or EPA.

Section 110(a)(2)(D) provides a tool for addressing the problem of transported pollution. This provision applies to all SIPs for each pollutant covered by a NAAQS and to all areas regardless of their attainment designation. Under section 110(a)(2)(D) a SIP must contain adequate provisions prohibiting sources in the State from emitting air pollutants in amounts that will contribute significantly to nonattainment in one or more downwind States.

The CAA section 110(k)(5) authorizes EPA to find that a SIP is substantially inadequate to meet any CAA requirement. If EPA makes such a finding, it must require the State to submit, within a specified period, a SIP revision to correct the inadequacy. This is generally known as a "SIP call." In 1998, EPA used this authority to issue the NO_x SIP Call, discussed below, to require States to revise their SIPs to include measures to reduce NO_x emissions that were significantly contributing to ozone nonattainment problems in downwind States.

2. What Is the NO_x SIP Call? [4]

In the early 1990's, EPA recognized that ozone transport played an important role in preventing downwind areas from developing attainment demonstrations. In response to a recommendation by the Environmental Council of States, EPA formed a national work group to assess and attempt to develop consensus solutions to the problem of interstate transport of ozone and its precursors in the eastern half of the country. This work group, the Ozone Transport Assessment Group (OTAG), which was active from 1995–1997, consisted of representatives from the 37 States in that region; the District of Columbia; EPA; and interested members of the public, including industry and environmental groups. The OTAG completed the most comprehensive analysis of ozone transport that had ever been conducted, developing technical data, including up-to-date inventories and state-of-the-art air quality modeling, to quantify and identify the sources of interstate ozone transport. The OTAG concluded that regional NO_x emissions reductions are effective in producing ozone benefits, while VOC controls are effective in reducing ozone locally and are most advantageous to urban nonattainment areas.

In 1998, EPA promulgated a rule, based in part on the work by OTAG, determining that 22 States [5] and the District of Columbia in the eastern half of the country significantly contribute to 1-hour and 8-hour ozone nonattainment problems in downwind States.[6] This rule, generally known as the NO_x SIP Call, required those jurisdictions to revise their SIPs to include NO_x control measures to mitigate the significant ozone transport. The EPA determined the emissions reductions requirements by projecting NO_x emissions to 2007 for all source categories and then reducing those emissions through controls that EPA determined to be highly cost effective. The affected States were required to submit SIPs providing the resulting amounts of emissions reductions.

Under the NO_x SIP Call, States have the flexibility to determine the mix of controls to meet their emissions reductions requirements. However, the rule provides that if the SIP controls EGUs, then the SIP must establish a budget, or cap, for EGUs. The EPA recommended that each State authorize a trading program for NO_x emissions from EGUs. We developed a model cap and trade program that States could voluntarily choose to adopt.

In response to litigation over EPA's final NO_x SIP Call rule, the U.S. Court of Appeals for the District of Columbia Circuit issued two decisions concerning the NO_x SIP Call and its technical amendments.[7] The Court decisions generally upheld the NO_x SIP Call and technical amendments, including EPA's

[4] For a more detailed background discussion, *see* 67 FR 8396; February 22, 2002.

[5] The jurisdictions are: Alabama, Connecticut, Delaware, District of Columbia, Georgia, Illinois, Indiana, Kentucky, Maryland, Massachusetts, Michigan, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin.

[6] *See* "Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone; Final Rule," 63 FR 57,356 (October 27, 1998). The EPA also published two Technical Amendments revising the NO_x SIP Call emission reduction requirements. (64 FR 26,298; May 14, 1999 and 65 FR 11222; March 2, 2000).

[7] *See Michigan* v. *EPA*, 213 F.3d 663 (D.C. Cir. 2000), *cert. denied*, 532 U.S. 904 (2001) (NO_x SIP call) and *Appalachian Power* v. *EPA*, 251 F.3d 1026 (D.C. Cir. 2001) (technical amendments).

interpretation of the definition of "contribute significantly" under CAA section 110(a)(2)(D). The litigation over the NO_x SIP Call coincided with the litigation over the 8-hour NAAQS. Because of the uncertainty caused by the litigation on the 8-hour NAAQS, EPA stayed the portion of the NO_x SIP Call based on the 8-hour NAAQS (65 FR 56245, September 18, 2000). Therefore, for the most part, the Court did not address NO_x SIP Call requirements under the 8-hour ozone NAAQS.

As in the NO_x SIP Call, in today's action EPA is exercising its Federal role to ensure States work in a coordinated way to solve regional pollution transport problems. Today's action follows the NO_x SIP Call approach in many ways.

3. What Is the Acid Rain Program and Its Relationship to This Proposal?

Title IV of the CAA Amendments of 1990 established the Acid Rain Program to address the deposition of acidic particles and gases. These particles and gases are largely the result of SO_2 and NO_x emissions from power plants that are transported over long distances in the atmosphere. In the environment, acid deposition causes soils and water bodies to acidify, making the water unsuitable for some fish and other wildlife. Acid deposition also damages forest soils by stripping soil nutrients, as well as damaging some sensitive tree species including maple and pine trees, particularly at high elevations. It speeds the decay of buildings, statues, and sculptures that are part of our national heritage. The nitrogen portion of acid deposition contributes to eutrophication in coastal ecosystems, the symptoms of which include algal blooms (some of which may be toxic), fish kills, and loss of plant and animal diversity. Finally, acidification of lakes and streams can increase the amount of methyl mercury available in aquatic systems. Most exposure to mercury results from eating contaminated fish.

The Acid Rain Program requires a phased reduction of SO_2 (and, to a lesser extent, NO_X) emissions from power generators that sell electricity. Larger EGUs were covered in 1995 with additional generators being added in 2000. Acid Rain Program affected sources would likely be affected by today's action, which proposes to require additional cost-effective SO_2 and NO_X reductions from large EGUs.

The Acid Rain Program utilizes a market-based cap and trade approach to require power plants to reduce SO_2 emissions to 50 percent of the 1980 emission levels. At full implementation after 2010, emissions will be limited (*i.e.*, "capped") to 8.95 million tons in the contiguous United States. Individual existing units are directly allocated their share of the total emissions allowances—each allowance is an authorization to emit a ton of SO_2—in perpetuity. New units are not allocated allowances. Today's rule builds off of the Acid Rain cap and trade program and allows sources to use SO_2 allowances to meet the proposed emissions caps. This effectively reduces the national cap on SO_2 emissions.

The Acid Rain Program has achieved major SO_2 emissions reductions, and associated air quality improvements, quickly and cost effectively. In 2002, SO_2 emissions from power plants were 10.2 million tons, 41 percent lower than 1980.[8] These emissions reductions have translated into substantial reductions in acid deposition, allowing lakes and streams in the Northeast to begin recovering from decades of acid rain. Cap and trade under the Acid Rain Program has created financial incentives for electricity generators to look for new and low-cost ways to reduce emissions, and improve the effectiveness of pollution control equipment, at costs much lower than predicted. The Program's cap on emissions, its requirement that excess emissions be offset with allowances (with the potential for fines and civil prosecution), and its stringent emissions monitoring and reporting requirements ensure that environmental goals are achieved and sustained, while allowing for flexible compliance strategies which take advantage of trading and banking. The level of compliance under the Acid Rain Program continues to be uncommonly high with over 99 percent of the affected sources holding sufficient allowances by the annual compliance deadline. Even this handful of non-compliant sources did not compromise the integrity of the cap because each ton emitted in excess of allowances must be automatically offset.

Title IV also specifies a two-part, rate-based strategy to reduce NO_X emissions from coal-fired electric power plants. Beginning in 1996 with larger units, the Acid Rain Program included smaller EGUs and required additional reductions from the larger units in 2000. By basing the required levels of NO_X reductions on commercially available combustion controls, title IV has reduced NO_X emissions to 2.1 million tons per year beginning in 2000. Utilities have the flexibility to comply with the rule by: (1) Meeting the standard annual emissions limitations; (2) averaging the emissions rates of two or more boilers; or (3) if a utility cannot meet the standard emission limit, applying for a less stringent alternative emission limit (AEL) based upon its unique application of NO_x emissions control technology on which the rule is based.

4. What Is the Regional Haze Program and Its Relationship to This Proposal?

Regional haze is visibility impairment that is caused by the same types of sources likely to be affected by this proposed rule. These types of sources emit fine particles and their precursors, and they are located across a broad geographic area.[9] In 1977, in the initial visibility protection provisions of the CAA, Congress specifically recognized that the "visibility problem is caused primarily by emission into the atmosphere of SO_2, oxides of nitrogen, and particulate matter, especially fine particulate matter, from inadequate[ly] controlled sources." [10] The fine particulate matter, or $PM_{2.5}$, that impairs visibility by scattering and absorbing light also causes serious health effects and mortality in humans discussed earlier in this section. Data from the existing visibility monitoring network show that visibility impairment caused by air pollution occurs virtually all of the time at most national park and wilderness area monitoring stations.[11]

Under the 1999 Regional Haze Rule,[12] States are required to set periodic goals for improving visibility in the 156 Class I areas, and to adopt long-term strategies to meet the goal of returning visibility in these areas to natural conditions (*see* 40 CFR part 81, subpart D). Today's proposal will reduce SO_2 and NO_X emissions in 29 States, assisting those States and their neighbors in making progress toward their visibility goals.

5. What Is the Proposed Utility Control Program for Air Toxics and Its Relationship to This Proposal?

Today's interstate air quality proposal affecting SO_2 and NO_X emissions is related to a proposal signed on December 15, 2003 to regulate mercury from certain types of EGU's using the

[8] U.S. Environmental Protection Agency, *EPA Acid Rain Program: 2002 Progress Report* (EPA 430–R–03–011), November 2003. (Available at: *http://www.epa.gov/airmarkets/cmprpt/arp02/2002report.pdf)*

[9] *See, e.g.*, U.S. EPA, National Center for Environmental Assessment, Office of Research and Development, Research Triangle Park, NC, *Air Quality Criteria for Particulate Matter*, EPA/600/P–95/001bF, April 1996.

[10] H.R. Rep. No. 95–294 at 204 (1977).

[11] National Park Service, *Air Quality in the National Parks: A Summary of Findings from the National Park Service Air Quality Research and Monitoring Program*. Natural Resources Report 88–1. Denver CO, July 1988.

[12] 64 FR 35714, July 1, 1999.

maximum achievable control technology (MACT) provisions of section 112 of the CAA or using the performance standards provisions under section 111 of the CAA.

The EPA believes that a carefully designed multi-pollutant approach—a program designed to control NO_X, SO_2, and mercury at the same time—is the most effective way to reduce emissions from electric utilities. One key feature of this approach is the interrelationship of the timing and cap levels for SO_2, NO_X, and mercury. Today, we know that electric utilities can reduce their emissions of all three pollutants by installing flue gas desulfurization (FGD) (which controls SO_2 and mercury emissions) and selective catalytic reduction (SCR) (which controls NO_X and mercury). We have designed the interstate transport proposal and the mercury section 111 proposal to take advantage of the combined emissions reductions that these technologies provide. Taken together, these proposals would coordinate emissions reductions from electric utilities to achieve necessary health protections cost effectively.

II. Characterization of the Origin and Distribution of 8-Hour Ozone and $PM_{2.5}$ Air Quality Problems

This section presents a simplified account of the occurrence, formation, and origins of ozone and $PM_{2.5}$, as well as an introduction to certain relevant scientific and technical terms and concepts that are used in the remainder of this proposal. It also provides scientific and technical insights and experiences relevant to formulating control approaches for reducing the contribution of transport to these air quality problems.

A. Ground-level Ozone

1. Ozone Formation

Ozone is formed by natural processes at high altitudes, in the stratosphere, where it serves as an effective shield against penetration of harmful solar UV–B radiation to the ground. The ozone present at ground level as a principal component of photochemical smog is formed in sunlit conditions through atmospheric reactions of two main classes of precursor compounds: VOCs and NO_X (mainly NO and NO_2). The term "VOC" includes many classes of compounds that possess a wide range of chemical properties and atmospheric lifetimes, which helps determine their relative importance in forming ozone. Sources of VOCs include man-made sources such as motor vehicles, chemical plants, refineries, and many consumer products, but also natural emissions from vegetation. Nitrogen oxides are emitted by motor vehicles, power plants, and other combustion sources, with lesser amounts from natural processes including lightning and soils. Key aspects of current and projected inventories for NO_X and VOC are summarized in section IV of this proposal and EPA Web sites (*e.g., http://www.epa.gov/ttn/chief*).

The relative importance of NO_X and VOC in ozone formation and control varies with location- and time-specific factors, including the relative amounts of VOC and NO_X present. In rural areas with high concentrations of VOC from biogenic sources, ozone formation and control is governed by NO_X. In some urban core situations, NO_X concentrations can be high enough relative to VOC to suppress ozone formation locally, but still contribute to increased ozone downwind from the city. In such situations, VOC reductions are most effective at reducing ozone within the urban environment and immediately downwind.

The formation of ozone increases with temperature and sunlight, which is one reason ozone levels are higher during the summer. Increased temperature increases emissions of volatile man-made and biogenic organics and can indirectly increase NO_X as well (*e.g.*, increased electricity generation for air conditioning). Summertime conditions also bring increased episodes of large-scale stagnation, which promote the build-up of direct emissions and pollutants formed through atmospheric reactions over large regions. The most recent authoritative assessments of ozone control approaches[13 14] have concluded that, for reducing regional scale ozone transport, a NO_X control strategy would be most effective, whereas VOC reductions are most effective in more dense urbanized areas.

2. Spatial and Temporal Patterns of Ozone

Studies conducted in the 1970's established that ozone occurs on a regional scale (*i.e.* 1000's of kilometers) over much of the Eastern U.S., with elevated concentrations occurring in rural as well as metropolitan areas.[15 16] While progress has been made in reducing ozone in many urban areas, the Eastern U.S. continues to experience elevated regional scale ozone episodes in the extended summer ozone season.

Regional 8-hour ozone levels are highest in the Northeast and Mid-Atlantic areas with peak 2002 (3-year average of the 4th highest value for all sites in the region) ranging from 0.097 to 0.099 parts per million (ppm).[17] The Midwest and Southeast States have slightly lower peak values (but still above the 8-hour standard in many urban areas) with 2002 regional averages ranging from 0.083 to 0.090 ppm. Regional-scale ozone levels in other regions of the country are generally lower, with 2002 regional averages ranging from 0.059 to 0.082 ppm. Nevertheless, some of the highest urban 8-hour ozone levels in the nation occur in southern and central California and the Houston area.

B. Fine Particles

1. Characterization and Origins of Fine Particles

Particulate matter is a chemically and physically diverse mixture of discrete particles and droplets. It exists in the air in a range of particle sizes, from submicrometer to well above 30 micrometers (μm). Most of the mass of particles is distributed in two size modes that are termed fine and coarse particles. Although there is some overlap at the division of the modes (1 to 3 μm), fine and coarse particles generally have different origins, source types, chemical composition, and atmospheric transport and removal processes. In particular, because of their small size and mechanisms of formation, fine particles can be created and transported substantial distances (hundreds to over 1000 km) from emission sources.

As noted above, EPA has established NAAQS for fine particles, which are defined as those smaller than a nominal 2.5 μm (aerodynamic diameter) or $PM_{2.5}$. Standards also exist for particles smaller than a nominal 10 μm aerodynamic diameter (or PM_{10}) which include both fine particles and inhalable coarse mode particles. For reasons summarized in section III below, today's proposal focuses on reducing significant transport of $PM_{2.5}$ as it affects attainment of the annual standards.

Fine particles can be directly emitted from sources or, like ozone, can be formed in the atmosphere from precursor gases. Directly emitted particles are often termed "primary" particles, while those formed in the

[13] Ozone Transport Assessment Group, *OTAG Final Report*, 1997.

[14] NARSTO, *An Assessment of Tropospheric Ozone Pollution—A North American Perspective*, July 2000.

[15] National Research Council, *Rethinking the Ozone Problem in Urban and Regional Air Pollution*, 1991.

[16] NARSTO, *An Assessment of Tropospheric Ozone Pollution—A North American Perspective*, July 2000.

[17] U.S. EPA, *Latest Findings on National Air Quality*, August 2003.

atmosphere are called "secondary" particles.[18] The most common source of directly emitted $PM_{2.5}$ is incomplete combustion of fuels containing carbon (fossil or biomass), which produces carbonaceous particles consisting of a variety of organic substances and black carbon (soot), as well as gaseous carbon monoxide, VOCs and NO_X. Certain high energy industrial processes also emit primary $PM_{2.5}$. Examples of direct $PM_{2.5}$ sources include diesel and gasoline vehicles, open burning, residential wood burning, forest fires, power generation, and industrial metals production and processing.

The major gaseous precursors of secondary $PM_{2.5}$ include SO_2, NO_X, certain VOCs and NH_3. The SO_2 and NO_X form, respectively, sulfuric and nitric acids, which then react with ammonia to form various sulfate and nitrate compounds. At typical summertime humidities in the East, these substances absorb water and the particles exist as tiny droplets. Ammonia generally would not form atmospheric particles in the absence of acidic sulfates and nitrates. Certain reactive VOCs of relatively high molecular weight (*e.g.*, toluene, xylenes in gasoline) can be oxidized to form secondary organic aerosol particles (SOA) in the same kinds of photochemical processes that produce ozone.

The major sources of secondary $PM_{2.5}$ forming gases (SO_2, NO_X, certain VOCs, NH_3) include nearly every source category of air pollutants. Major SO_2 sources in the U.S. include coal-fired power plants and industrial boilers and smelters. Major NO_X sources were summarized in subsection 1 (ozone) above. Significant man-made sources of organic PM precursors (particularly aromatic compounds[19]) include motor vehicle fuels, solvents, petrochemical facilities, diesel and gasoline vehicle emissions, and biogenic emissions from trees. Ammonia is emitted from numerous livestock and other agricultural activities and natural processes in soil, but smaller source categories may be important in urban areas.

Secondary formation of $PM_{2.5}$ involves complex processes that depend on factors such as the amounts of needed precursor gases; the concentrations of other reactive species such as ozone (O_3), hydroxyl radicals (OH^-), or hydrogen peroxide (H_2O_2); atmospheric conditions including solar radiation, temperature and relative humidity (RH); and the interactions of precursors and pre-existing particles with cloud or fog droplets or in the liquid film on solid particles. Significantly, these processes indicate an important link between $PM_{2.5}$ and the pollutants and sources that form ozone. More complete discussions of the formation and characteristics of secondary particles can be found in the U.S. EPA Criteria Document,[20] and in the recent NARSTO Fine Particle Assessment.[21] More complete discussions of the characteristics and sources of both primary and secondary particles can be found in the U.S. EPA Staff Paper on Review of the National Ambient Air Quality Standards for Particulate Matter.[22]

2. Spatial and Temporal Patterns of $PM_{2.5}$ and Major Components

As noted in section I above, the most recent $PM_{2.5}$ monitoring data (2000–2002) show numerous counties in violation of the annual standards across much of the Eastern U.S., as well as in southern and central California. A major reason for the high values in eastern urban areas is the regional contributions from sources distant to these areas.[23] This is illustrated by comparing recent $PM_{2.5}$ data from the EPA Speciation Network (urban sites) and the IMPROVE Network (non-urban sites). A tabular summary comparing these urban and rural ambient data is included in the Air Quality Data Analysis Technical Support Document. This comparison suggests that in the East, rural regional transport contributes well over half of the $PM_{2.5}$ observed in urban areas.

The EPA Speciation Network and IMPROVE data also permits comparison of the regional contribution of the major components that comprise $PM_{2.5}$. The major chemical compounds/classes typically measured or estimated include sulfate, and nitrate, ammonium (estimated from sulfate and nitrate in IMPROVE), total carbonaceous materials (TCM), including black carbon and estimated organic carbon, and crustal-related materials. The crustal materials reflect intrusion of the smallest particles originating in the coarse mode as well as a number of fine mode metals and other elements present in small amounts.

Nationally, the most recent urban $PM_{2.5}$ composition data show a significant contribution of carbonaceous material at all sites, with sulfates higher in the East and nitrates higher in the West. Crustal material is typically less than 5 to 10 percent of the total. Focusing on the rural eastern sites representative of the regional contribution, sulfates and associated ammonium are the largest fraction, followed by carbonaceous material. Nitrates are also a significant contributor to $PM_{2.5}$ in the more northern areas of the Eastern U.S., especially in the industrial Midwest (about 20 percent).

Rao and Frank[24] (2003) have compared the concentrations of sulfates and carbonaceous particles for specific pairs of urban and nearby non-urban sites. In the East, sulfate at urban monitoring locations is only slightly higher than at nearby non-urban sites. In contrast, carbonaceous material at urban sites is significantly higher than at the non-urban sites. The similarity of urban and rural sulfates suggests that ambient sulfate is present on a regional scale and that most urban sulfate is likely associated with regional transport. On the other hand, urban carbonaceous material appears to have both a regional and an urban component. The much higher concentrations in urban areas indicate the importance of local sources. Detailed source apportionment studies discussed in section V below suggest that mobile and other combustion sources, which are much more concentrated in urban areas, may explain much of the elevated urban carbon concentrations.

Seasonal variations in $PM_{2.5}$ and components provide useful insights into the relative importance of various sources and atmospheric processes. In the East, rural $PM_{2.5}$ concentrations are usually significantly higher in the summertime than in the winter. In large urban areas, however, summer/winter differences are smaller, and winter peaks may be higher. More specifically, $PM_{2.5}$ concentrations in urban areas in the Northeast, industrial Midwest, and upper Midwest regions peak both in the winter and in the summer and are

[18] These terms used in the context of atmospheric science should not be confused with similar terms that are used in section 109 of the CAA to distinguish standards that are intended to protect public health (primary) from those that protect public welfare (secondary).

[19] Grosjean, D., Seinfeld, J.H., *Parameterization of the formation potential of secondary organic aerosols*, Atmospheric Environment 23, 1733–1747, 1989.

[20] U.S. EPA, National Center for Environmental Assessment, *Air Quality Criteria for Particulate Matter, 4th External Review Draft*. June 2003.

[21] NARSTO, *Particulate Matter Science for Policy Makers—A NARSTO Assessment*. February 2003.

[22] U.S. EPA, *Review of the National Ambient Air Quality Standards for Particulate Matter: Policy Assessment of Scientific and Technical Information OAQPS Staff Paper—First Draft*. August 2003.

[23] NARSTO, *Particulate Matter Science for Policy Makers—A NARSTO Assessment*. February 2003.

[24] V. Rao, N. Frank, A. Rush, F. Dimmick, *Chemical Speciation of $PM_{2.5}$ in Urban and Rural Areas*, In the Proceedings of the Air & Waste Management Association Symposium on Air Quality Measurement Methods and Technology, San Francisco, on November 13–15, 2002.

lowest in the spring and fall. The concentrations in the peak seasons in the Northeast and industrial Midwest are 5 μg/m³ or more higher in concentration than the low seasons. The peak seasons in the upper Midwest are less than 5 μg/m³ higher than the low seasons. In the Southeast, however, the urban areas have just one peak that occurs in the summer, and that peak is only 4 to 5 μg/m³ higher than the lowest season.

The seasonal pattern of summer $PM_{2.5}$ peaks in rural areas does not vary as much by region as do urban patterns. The composition data show that these summer peaks are due to elevated regional sulfates and organic carbon. Urban and rural nitrates tend to be low in the summer and significantly higher in the winter, when sulfates are lowest. Wintertime urban peaks appear to consist of increased ammonium nitrate and carbonaceous material of local origin.[25]

3. Implications for Control of Transported $PM_{2.5}$

The interplay between sulfates and nitrates observed in the seasonal data above is of particular importance. The formation of ammonium nitrate is favored by availability of ammonia and nitric acid vapor, low temperatures, high relative humidity, and the absence of acid sulfate particles. At higher summer temperatures when photochemical processes and meteorological conditions in the East produce high sulfate levels, ammonia and nitric acid vapor tend to remain in the gas phase rather than forming ammonium nitrate particles. In winter months, with cooler temperatures and lower sulfur-related acidity, the presence of sufficient nitric acid and ammonia favors formation of nitrate particles.

The chemistry summarized above has consequences for the effectiveness of SO_2 reductions in lowering regional and urban $PM_{2.5}$ concentrations. Both observations and modeling simulations (*see* subsection II.B.4 below) suggest that regional SO_2 reductions are effective at reducing sulfates and $PM_{2.5}$. When SO_2 reductions reach a certain point in relation to other relevant reactants and conditions, however, the ammonia formerly associated with sulfate can react with excess nitric acid vapor to form nitrate particles, effectively replacing at least part of the $PM_{2.5}$ reduction due to sulfate. This phenomenon is termed "nitrate replacement." Under these conditions, SO_2 reductions will not be as effective at reducing $PM_{2.5}$. Empirical evidence based on ambient measurements and modeling simulations show nitrate replacement changes under differing scenarios involving meteorological factors and relative concentrations of important components.[26,27] Obviously, sulfate reduction approaches (SO_2 controls) will be more effective at lowering $PM_{2.5}$ if complemented by strategies that reduce nitrates (NO_X controls), particularly in the winter.

This chemistry also has implications for the role of ammonia sources in contributing to regional $PM_{2.5}$. As noted above, ammonia would not be present in particle form were it not for the presence of sulfuric and nitric acids. Significant reductions of these acids through SO_2 and NO_X controls would also reduce particulate ammonia, without the need for ammonia controls. As evidenced in the discussion above, it is clear that any effects of ammonia emissions controls on $PM_{2.5}$ would vary considerably with the concentrations of sulfate, total ammonia (gas phase plus aerosol), total nitric acid temperature, and location and season. In some cases, a decrease in ammonia will have no effect on $PM_{2.5}$, while in other cases, the decrease will reduce total nitrate contributions.[28]

In essence, the effect of significant reductions in ammonia on $PM_{2.5}$ is least in conditions with low particulate nitrate levels (*e.g.*, warm conditions) or low nitric acid vapor levels (*e.g.*, through NO_X reductions) in comparison to ammonia levels. The most significant effects of ammonia control would occur in conditions where there is an abundance of nitric acid, in which ammonia limits particulate nitrate formation. Therefore, significant reductions in SO_2 and NO_X emissions would create conditions that would reduce the effectiveness of ammonia controls in reducing $PM_{2.5}$.

In addition to these direct effects of ammonia controls on $PM_{2.5}$, ammonia is a weak base that serves to partially neutralize acids that occur in $PM_{2.5}$. As such, reducing ammonia will make $PM_{2.5}$, clouds, and precipitation more acidic, thereby exacerbating acidifying precipitation (acid rain) and possibly causing health effects related to $PM_{2.5}$ acidity. Through this increased acidity of clouds and fogs, ammonia reductions can slow the conversion of SO_2 to particle sulfate.[29] The increased acidity associated with ammonia reductions may also increase the formation of secondary organic aerosols, according to recent laboratory studies.[30] In contrast, NO_X reductions can both slow sulfate formation through oxidant chemistry, while also reducing acidity.

A further complication in consideration of ammonia controls is the uncertainty regarding the location and temporal variations in ammonia emissions, particularly in urban areas. This is an area of active research and investigation for EPA and others. It is of note that the maximum concentration of ammonium nitrates occurs in the winter, a period that is expected to have the lowest ammonia emissions from agricultural activities;[31] by contrast, the potential $PM_{2.5}$ benefit of reducing ammonia emissions in the summer when they may be at a peak is limited to the ammonium itself, because this is the time of lowest ammonium nitrate particle levels.

The origins of the carbonaceous component of regional transport are even less well characterized. It reflects a complex mixture of hundreds or even thousands of organic carbon compounds, most of which have not yet been successfully quantified. In addition to directly emitted carbonaceous materials from fires and transport from urban areas, a varying amount is likely derived from biogenic emissions—which may include both primary and transformed secondary materials. Because the observed summertime increase in organic particles may be related to photochemical activity, it is reasonable to expect that—as for regional ozone—NO_X reductions might produce some benefits. Further, recent work by Jang *et al.* suggests that acidic aerosols (*e.g.*, sulfates) *may* increase the formation of secondary organic aerosols (SOA).[32]

Despite significant progress that has been made in understanding the origins

[25] NARSTO, *Particulate Matter Science for Policy Makers—A NARSTO Assessment.* February 2003.

[26] NARSTO, *Particulate Matter Science for Policy Makers—A NARSTO Assessment.* February 2003.

[27] Blanchard and Hidy. J., *Effects of Changes in Sulfate, Ammonia, and Nitric Acid on Particulate Nitrate Concentrations in the Southeastern United States,* Air & Waste Manage. Assoc. 53:283–290. 2003.

[28] The marginal effectiveness of reducing ammonia on $PM_{2.5}$ is examined in West, J. J., A. S. Ansari, and S. N. Pandis, *Marginal $PM_{2.5}$*: nonlinear aerosol mass response to sulfate reductions in the eastern U.S., Journal Air & Waste Management Assoc., 49(12): 1415–1424, 1999.

[29] NARSTO, *Particulate Matter Science for Policy Makers—A NARSTO Assessment.* February 2003.

[30] Jang, M.; Czaschke, N. M.; Lee, S.; Kamens, R. M., *Heterogeneous Atmospheric Aerosol Production by Acid-Catalyzed Particle Phase Reactions,* Science, 2002, 298, 814–817.

[31] Battye, W., V. P. Aneja, and P. A. Roelle, *Evaluation and improvement of ammonia emissions inventories, Atmospheric Environment,* 2003, 37, 3873–3883.

[32] Jang, M.; Czaschke, N. M.; Lee, S.; Kamens, R. M., *Heterogeneous Atmospheric Aerosol Production by Acid-Catalyzed Particle Phase Reactions,* Science, 2002, 298, 814–817.

and properties of SOA, it remains the least understood component of $PM_{2.5}$. Moreover, the contribution of primary and secondary organic aerosol components to measured organic aerosol concentrations is thought to be highly variable and is a controversial issue.[33] The relative amounts of primary versus secondary organic compounds in the ambient air throughout the U.S., however, appear to vary with location and time of year. While carbonaceous material appears to be a significant component in regional transport in the East, it is currently not possible to determine with certainty the relative contribution of primary versus secondary carbonaceous particles, or to fully quantify the fraction that might be reduced by control of man-made sources. The EPA and others have funded substantial research and monitoring efforts to clarify these issues. New information from the scientific community continues to emerge to improve our understanding of the relationship between sources of PM precursors and secondary particle formation.

4. Air Quality Impacts of Regional SO_2 Reductions

As noted above, sulfates from SO_2 comprise the largest component of regional transport in the East. Fortunately, we already have significant observational evidence of the effectiveness of reducing regional SO_2 emissions. By contrast, while small to modest NO_X emissions reductions from control programs to date have resulted in reduced nitrate deposition in some portions of the East,[34] we have no comparable long-term experience in observing the expected effects of more substantial regional reductions for NO_X. Perhaps the best documented example of the results of any major regional air pollution control program is reflected in the experience of the title IV Acid Rain Program (*see* section VIII below). From 1990 to date, this market-based program reduced SO_2 emissions from electric utilities throughout the country, with most of the emissions reductions achieved by sources in the East. The regional reductions have resulted in substantial improvements in air quality and deposition throughout the East. The spatial and temporal patterns of these improvements have been observed at most eastern rural monitoring networks.[35]

The signal of regional air quality has been detected by the CASTNET. The CASTNET sites in rural areas of the Midwest and East measured high average SO_2 concentrations prior to the Acid Rain Program, particularly in areas of the Ohio River Valley and into New York and eastern Pennsylvania where electric utility SO_2 emissions were high. Average concentrations of sulfates throughout this area were elevated throughout an even broader region, indicating that sulfates were being transported from the SO_2 emission sources to areas throughout the East.

Since 1990, SO_2 concentrations at CASTNET sites have been reduced substantially in the areas where concentrations were high before the Acid Rain Program.[36] A comparison of current mean SO_2 concentrations (3-year average 2000–2002) to SO_2 concentrations before the Program (1990–1992) shows that all sites decreased. The largest decrease was observed at sites from Illinois to northern West Virginia across Pennsylvania to western New York.

Rural monitoring networks have also been able to detect temporal patterns in SO_2 and sulfate concentrations. Temporal trends in rural concentrations of these pollutants can be used to determine if monitored concentrations responded to changes in emissions trends. The most substantial drop in SO_2 emissions occurred in 1995 when Phase I of the Acid Rain Program began. After 1995, emissions increased slightly, as sources began to use allowances that they had banked by reducing emissions before the program began, until Phase II of the program began in 2000 and emissions declined again.[37]

Monitored SO_2 concentrations, sulfate concentrations at eastern CASTNET sites, sulfur concentrations in precipitation at eastern National Atmospheric Deposition (NADP) sites, and total (Dry + Wet) sulfur deposition at NADP and CASTNET sites closely tracked the yearly trends in SO_2 emissions from Acid Rain Program sources from 1990–2002. Notably, the most significant decline in the various pollutants was observed in 1995 immediately after Phase I began.[38]

These trends in air quality and deposition at rural monitoring sites show that a large, regional emission reduction program can achieve significant, observable environmental improvements throughout a broad area, especially where pollution levels are elevated before the program is implemented. In addition, the temporal trend in observed improvements shows that emissions reductions can lead to immediate environmental improvements. Additional discussions of the air quality impacts of regional SO_2 reductions can be found in the U.S. Air Quality and Emission Trends Report,[39] as well as recent reports from IMPROVE[40] and the National Atmospheric Deposition Program.[41]

III. Overview of Proposed Interstate Air Quality Rule

A. Purpose of Interstate Air Quality Rule

For this rulemaking, EPA has assessed the role of transported emissions from upwind States in contributing to unhealthy levels of $PM_{2.5}$ and 8-hour ozone in downwind States. Based on that assessment, the EPA is proposing emissions reduction requirements for SO_2 and NO_X that would apply to upwind States.

Emissions reductions to eliminate transported pollution are required by the CAA and supported by sound policy. Clean Air Act section 110(a)(2)(D) requires SIP revisions for upwind States to eliminate emissions that contribute significantly to nonattainment downwind. Under section 110(a)(1), these SIP revisions were required in 2000 (three years after the 1997 revision of the $PM_{2.5}$ and 8-hour ozone NAAQS); EPA proposes that they be submitted as expeditiously as practicable, but no later than 18 months after the date of promulgation.

There are also strong policy reasons for addressing interstate pollution transport, and for doing so now. First, emissions from upwind States can alone, or in combination with local emissions, result in air quality levels that exceed the NAAQS and jeopardize the health of citizens in downwind communities. Second, interstate pollution transport requires some consideration of reasonable balance between local and regional controls. If significant contributions of pollution from upwind States go unabated, the downwind area must achieve greater

[33] NARSTO, *Particulote Matter Science for Policy Makers—A NARSTO Assessment*. February 2003.

[34] Butler, Thomas J., Gene E. Likens, Francoise M. Vermeylen and Barbara J. B. Stunder. The relation between NO_X emissions and precipitation NO_3- in the eastern USA, Atmospheric Environment, Volume 37, Issue 15, May 2003, Pages 2093–2104.

[35] U.S. EPA, *Clean Air Status and Trends Network 2002 Annual Report*. November 2003.

[36] U.S. EPA, *Acid Rain Progress Report*, November 2003.

[37] U.S. EPA, *Clean Air Status and Trends Network 2002 Annuol Report*, November 2003.

[38] U.S. EPA, *Clean Air Status and Trends Network 2002 Annual Report*. November 2003.

[39] U.S. EPA, *Nationol Air Quality and Emissions Trends Report*, 1999. March 2001.

[40] Malm, William C., *Spatial ond Seasonal Patterns and Temporal Variability of Haze and its Constituents in the United States:" Report III*. May 2000.

[41] *Notionol Atmospheric Deposition Program, National Atmospheric Deposition Program, 2002 Annual Summary*. 2003.

local emissions reductions, thereby incurring extra clean-up costs in the downwind area. Third, requiring reasonable controls for both upwind and local emissions sources should result in achieving air quality standards at a lesser cost than a strategy that relies solely on local controls. For all these reasons, EPA believes it is important to address interstate transport as early as possible. Doing so as we are today, in advance of the time that States must adopt local nonattainment plans, will make it easier for states to develop plans to reach attainment of the standards.

The EPA previously addressed interstate pollution transport for ozone in rules published in 1998 and 2000. These rules, known as the NO_X SIP Call and Section 126 Rule, are substantially reducing ozone transport and helping downwind areas meet the 1-hour and 8-hour ozone standards. However, EPA is reassessing ozone transport in this rulemaking for two reasons. First, several years have passed since promulgation of the NO_X SIP Call and updated data are available. Second, in view of the difficulty some areas are expected to have meeting the 8-hour ozone standards, EPA believes it is important to assess the degree to which ozone transport will remain a problem after full implementation of the existing rules, and to determine whether further controls are warranted to ensure continued progress toward attainment. Today's rulemaking is EPA's first attempt to address interstate pollution transport for $PM_{2.5}$.

B. Summary of EPA's Key Findings and Proposed Remedy for Interstate Transport

Based on a multi-part assessment summarized below, EPA has concluded that:

- Without adoption of additional emissions controls, a substantial number of urban areas in the central and eastern regions of the U.S. will continue to have levels of $PM_{2.5}$ or 8-hour ozone (or both) that do not meet the national air quality standards.
- Although States have not yet developed plans for meeting the $PM_{2.5}$ and 8-hour ozone standards, predictive analyses by EPA for the year 2010 show that even with implementation of substantial local controls, many areas would continue to experience unhealthy air quality in that year. Consequently, EPA has concluded that small contributions of pollution transport to downwind nonattainment areas should be considered significant from an air quality standpoint because these contributions could prevent or delay downwind areas from achieving the health-based standards.
- Based on our analyses, we have concluded that SO_2 and NO_X are the chief emissions contributing to interstate transport of $PM_{2.5}$. For the 8-hour ozone nonattainment, EPA continues to believe, in accordance with the conclusion of the Ozone Transport Assessment Group (OTAG), that the focus of interstate transport control should be on NO_X.
- For both $PM_{2.5}$ and 8-hour ozone, EPA has concluded that interstate transport is a major contributor to the projected nonattainment problem in the Eastern U.S. in 2010. In the case of $PM_{2.5}$, the nonattainment areas analyzed are estimated to receive a transport contribution attributable to SO_2 and NO_X emissions ranging from 4.22 to 7.36 $\mu g/m^3$ on an annual average basis, with an average of 5.47 $\mu g/m^3$ across all nonattainment areas. In the case of 8-hour ozone, the nonattainment areas analyzed receive a transport contribution of more than 20 percent of their ambient ozone concentrations, and 21 of 47 had a transport contribution of more than 50 percent.
- Typically, two or more States contribute transported pollution to a single downwind area, so that the "collective contribution" is much larger than the contribution of any single State.

Based on these conclusions, EPA is proposing to make several findings, and to require the remedy summarized below:

- For $PM_{2.5}$, we are proposing to find that SO_2 and NO_X emissions in 28 States and the District of Columbia will contribute significantly in 2010 to $PM_{2.5}$ levels in downwind nonattainment areas in amounts that exceed an air quality significance threshold proposed today.
- For ozone, we are proposing to find that NO_X emissions in 25 States and the District of Columbia will contribute significantly in 2010 to ozone levels in excess of the 8-hour standards in downwind nonattainment areas in amounts that exceed the air quality significance threshold EPA previously established in the 1998 NO_X SIP Call, and which we propose today to continue to use.
- We are also proposing to find that emissions reductions from EGUs in the identified upwind States and the District of Columbia would be highly cost effective. As in the NO_X SIP Call, we propose to find that these highly cost-effective reductions constitute the significant contributions to downwind nonattainment in other States that must be eliminated under the CAA.
- We are proposing that the level of reductions that would be highly cost effective corresponds to power sector emissions caps in a 28-state plus District of Columbia region of 2.7 million annual tons for SO_2 and 1.3 million annual tons for NO_X.
- In order to strike a balance between the feasibility of achieving a substantial amount of emissions reductions, and the need to achieve them as expeditiously as practicable for attainment of health standards, we are proposing that the emissions caps for the affected States (and the District of Columbia) be implemented in two phases, with the first phase in 2010 and the second phase in 2015. The first phase caps would be 3.9 million tons for SO_2 and 1.6 million tons for NO_X.
- We estimate that, compared to the emissions that would otherwise occur in 2010 and 2015, this proposal would result in emissions reductions of 3.6 million tons SO_2 (40 percent) and 1.5 million tons NO_X (49 percent) by 2010, and 3.7 million tons SO_2 (44 percent) and 1.8 million tons NO_X (58 percent) by 2015.
- Compared to EGU emissions in 2002 in the affected States, at full implementation of today's proposal SO_2 emissions would be reduced about 71 percent. On the same basis, NO_X emissions would be reduced 65 percent.
- The proposed emissions reductions would be met by affected States using one of two options for compliance: (1) Participating in an interstate cap and trade system that caps emissions from the electric generating sector, thereby reducing the costs of emissions reductions while ensuring that the required reductions are achieved by the region as a whole (an approach EPA believes is preferable); or (2) meeting an individual State emissions budget through measures selected by the State in accord with the requirements discussed in sections VI and VII below.

Today's proposal relies on information and analysis relevant to determining whether sources in upwind States emit in amounts that "contribute significantly to [downwind] nonattainment," which the upwind States' SIPs are required to prohibit under section 110(a)(2)(D)(i)(I).

C. Coordination of Multiple Air Quality Objectives in Today's Rulemakings

1. Linkages Between Interstate Air Quality and Mercury Rulemakings

As noted above, today's proposal for reducing the transport of pollutants that contribute significantly to violations of the $PM_{2.5}$ and 8-hour ozone air quality standards is accompanied by separate actions proposing EPA's approach for addressing mercury from power plants. The EPA has endeavored to recognize and integrate the pollution reduction requirements incorporated in today's proposed rules so as to provide benefits for public health and the environment in a manner that has proven effective in other programs. In so doing, we were guided by our experience and success in implementing the title IV Acid Rain Program for reducing some of the same pollutants. We have also fully considered the extensive analyses and assessment of options that EPA has conducted over the last eight years in developing proposals that would establish an integrated multi-pollutant program for addressing the power sector, including the President's Clear Skies Act.

Our experience with title IV and the assessments leading to the proposed Clear Skies Act have suggested that we can achieve substantial benefits at reduced costs by expanding the market-based mechanisms of title IV to achieve substantial reductions in SO_2, NO_X, and mercury, and by recognizing the interactions inherent in designing control strategies in an integrated rather than sequential manner. This approach has the added advantage of providing regulatory certainty, both for the States, which are charged with developing attainment strategies for areas that are affected by interstate transport, and for sources that would be affected by today's proposed rules for addressing transport and mercury emissions.

While EPA still hopes that Congress will adopt the Administration's Clear Skies multi-pollutant legislation, the outcome of that process is not certain. Accordingly, we believe it is our responsibility to move forward to achieve these reductions as expeditiously as possible under existing regulatory authorities. We believe today's proposals reflect the best regulatory approach for making expeditious progress towards meeting air quality standards and other health and environmental goals, while providing flexibility that will minimize the cost of compliance. We have incorporated ambitious emissions reduction schedules to ensure the combined reductions of all pollutants occur as quickly as is feasible. We are proposing to offer, as an option for implementing the SO_2 and NO_X reductions, emissions cap and trade programs that would provide a seamless transition from the current title IV and NO_X SIP Call programs.

2. Linkages Between $PM_{2.5}$ and 8-hour Ozone Transport Requirements

Although $PM_{2.5}$ and ozone are distinct NAAQS with separate implementation requirements, in reality they are closely linked in many ways. Because of these linkages, we have considered $PM_{2.5}$ and ozone in an integrated manner in developing this proposal. The linkages between $PM_{2.5}$ and ozone arise from their interactions in atmospheric chemistry, the overlap in the pollutants and emission sources that contribute to elevated ambient levels, and similarities in their implementation schedules. Emissions of NO_X and SO_2 contribute to $PM_{2.5}$ nonattainment, and NO_X emissions also contribute to 8-hour ozone nonattainment. Moreover, because the power generation sector and other source types are major emitters of both NO_X and SO_2, and because control actions for these pollutants may reinforce or compete with each other, it is also appropriate to address NO_X and SO_2 control requirements in an integrated manner, keeping in mind that the relevant provisions of the CAA must, in the end, be met for each NAAQS and its associated pollutant precursors.

3. Linkages Between Interstate Air Quality Rulemaking and Section 126 Petitions

Recent history of how EPA and the States have relied on certain CAA transport provisions indicates that a brief discussion of these provisions may be useful. In the NO_X SIP Call rule, we determined that under section 110(a)(2)(D), the SIP for each affected State (and the District of Columbia) must be revised to eliminate the amount of emissions that contribute significantly to nonattainment in downwind States. We further determined that amount, for each State, as the quantity of emissions that could be eliminated by the application of highly cost-effective controls on specified sources in that State.

During July-August, 1997, EPA received petitions under CAA section 126 from eight northeastern states. The petitions asked EPA to find that specified sources in specified upwind States were contributing significantly to nonattainment in the petitioning States. Shortly after promulgation of the NO_X SIP Call, in May, 1999, EPA promulgated a rule making affirmative technical determinations for certain of the section 126 petitions. Relying on essentially the same record as we had for the NO_X SIP Call rulemaking, we made the affirmative technical determinations with respect to the same sources in certain of the same States covered under the NO_X SIP Call. Moreover, we approved a section 126 remedy based on the same set of highly cost-effective controls. However, EPA withheld granting the findings for the petitions. Instead, we stated that because we had promulgated the NO_X SIP Call—a transport rule under section 110(a)(2)(D)—as long as an upwind State remained on track to comply with that rule, EPA would defer making the section 126 finding. 64 FR 28250 (May 25, 1999) ("May 1999 Rule").

Following promulgation of the May 1999 Rule, however, the U.S. Court of Appeals for the D.C. Circuit stayed the NO_X SIP Call. We then promulgated a revised section 126 rule, in January 2000. 65 FR 2674 (January 18, 2000) ("January 2000 Rule"). We stated that because upwind States were no longer obliged to adhere to the requirements of the NO_X SIP Call, we would go ahead and make the section 126 findings.

Even so, in the January 2000 Rule, we further indicated that we were considering rescinding the section 126 finding with respect to an affected State if, in general, we approved a SIP revision submitted by the affected State as fully achieving the amount of reductions required under the NO_X SIP Call. The reason for this rescission would be the fact that the affected State's SIP revision would fulfill the section 110(a)(2)(D) requirements, so that there would no longer be any basis for the section 126 finding with respect to that State. In this manner, the NO_X SIP Call and the Section 126 Rules would be harmonized.

Today, we are similarly proposing a remedy under section 110(a)(2)(D) to eliminate the significant contribution of emissions, in this case both SO_2 and NO_X, from upwind States to downwind States' nonattainment of the fine particle and 8-hour ozone standards. We believe it would be appropriate to apply the same approach to any section 126 petitions submitted in the future, should there be any, as we used under the NO_X SIP Call and the related section 126 rules. Thus, we expect that the remedy we would provide in response to a section 126 petition concerning reductions in EGU emissions of SO_2 or NO_X by 2010 would be identical to that provided in this rulemaking under section 110(a)(2)(D), assuming that the petition relies on essentially the same record. Thus, we would expect to take the same position we took in the May 1999 Rule—that as long as EPA has promulgated a transport rule under section 110(a)(2)(D), the transport rule and the section 126 timeframes are roughly comparable, and a State is on track to comply with the transport rule, then EPA is not required to approve section 126 petitions targeting sources in that State if those petitions rely on essentially the same record.

If a section 126 petition is submitted, we would obviously need to set out in more detail our approach to the interaction between section 110(a)(2)(D) and section 126 in our response to that petition. Today, we are setting forth our general view of the relationship between these two sections and seeking comment on this view and on the issues raised by the interaction between these sections.

D. Overview of How EPA Assessed Interstate Transport and Determined Remedies

This section provides a conceptual overview of the EPA's technical and legal analyses of the problem of interstate pollution transport as it affects attainment of the $PM_{2.5}$ and 8-hour ozone standards. It is intended to provide an overall context for the more detailed discussions below. In general, EPA has taken a two-step approach in interpreting section 110(a)(2)(D). In the first step, EPA conducted an air quality assessment to identify upwind States which contribute significantly (before considering cost) to downwind nonattainment. In the second step, EPA conducted a control cost assessment to determine the amount of emissions in each upwind State that should be reduced in order to eliminate each upwind State's significant contribution to downwind nonattainment.

This two-step approach involved multiple technical assessments, which are listed below in brief, and explained in further detail in the subsections that follow. The EPA addressed:

(1) The degree and geographic extent of current and expected future nonattainment with the $PM_{2.5}$ and 8-hour ozone NAAQS;

(2) The potential impact of local controls on future nonattainment;

(3) The potential for individual pollutants to be transported between States;

(4) The extent to which pollution transport across State boundaries will contribute to future $PM_{2.5}$ and 8-hour ozone nonattainment; and

(5) The availability and timing of emissions reduction measures that can achieve highly cost-effective reductions in pollutants that contribute to excessive $PM_{2.5}$ and 8-hour ozone levels in downwind nonattainment areas.

1. Assessment of Current and Future Nonattainment

The EPA assessed the degree and geographic extent of current nonattainment of the $PM_{2.5}$ and 8-hour ozone NAAQS. For the 3-year period 2000–2002, 120 counties with monitors exceed the annual $PM_{2.5}$ NAAQS and 297 counties with monitor readings exceed the 8-hour ozone NAAQS.[42] Nonattainment of the $PM_{2.5}$ standards exists throughout the Eastern U.S.—from western Illinois and Tennessee eastward—and in California. Nonattainment of the 8-hour ozone standards also exists widely east of the continental divide—from eastern Texas and Oklahoma to the Atlantic coast—as well as in California and Arizona.

In analyzing significant contribution to nonattainment, we determined it was reasonable to exclude the Western U.S., including the States of Washington, Idaho, Oregon, California, Nevada, Utah, and Arizona from further analysis due to geography, meteorology, and topography. Based on these factors, we concluded that the $PM_{2.5}$ and 8-hour ozone nonattainment problems are not likely to be affected significantly by pollution transported across these States' boundaries. Therefore, for the purpose of assessing States' contributions to nonattainment in other States, we have only analyzed the nonattainment counties located in the rest of the U.S.

We assessed the prospects for future attainment and nonattainment in 2010 and 2015 with the 8-hour ozone NAAQS using the Comprehensive Air Quality Model with Extensions (CAM_X), and with the $PM_{2.5}$ NAAQS using the Regional Modeling System for Aerosols and Deposition (REMSAD).[43] These two forecasting years were chosen because they include the range of expected attainment dates for many $PM_{2.5}$ nonattainment areas, and under our proposed 8-hour implementation rule, the range of expected attainment dates for many 8-hour ozone nonattainment areas. In addition, considering the likely schedule for this rulemaking and the implementation steps that would follow it (*see* section VII), we believe that 2010 would be the first year in which sizable emission reductions could confidently be expected as a result of this rulemaking.

In modeling the 2010 and 2015 "base cases," we took into account adopted State and Federal regulations (*e.g.*, mobile source rules, the NO_X SIP Call) as well as regulations that have been proposed and that we expect will be promulgated before today's proposal is finalized.

Based on this approach we predicted that, in the absence of additional control measures, 47 counties with air quality monitors would violate the 8-hour ozone NAAQS in 2010, and 34 counties would violate in 2015. For $PM_{2.5}$ we predicted that 61 counties would violate the standards in 2010, and 41 counties would violate in 2015.[44] These counties are listed in Tables IV–3 and IV–4. The counties with predicted nonattainment are widely distributed throughout the central and eastern regions of the U.S. The degree of predicted nonattainment in both years spans a range of values from close to the NAAQS level to well above the NAAQS level. Given the number and geographic extent of predicted future nonattainment problems, we continued the assessment to quantify the role of interstate contributions to nonattainment.

2. Prospects for Progress Towards Attainment Through Local Reductions

The assessments of future nonattainment presented above considered only the effect of emission reduction measures already adopted or that are specifically required and that we expect will be adopted by the time this rule is promulgated. Once designated, States containing $PM_{2.5}$ and 8-hour ozone nonattainment areas will be required to submit SIPs that may include additional local emission reduction measures designed to achieve attainment. Accordingly, we assessed, to the extent feasible with available methods, whether it would be possible for nonattainment areas to attain the annual $PM_{2.5}$ and 8-hour ozone NAAQS through local emissions reductions with reasonably available control measures, or whether the amount of transport from

[42] *See* "Air Quality Data Analysis Technical Support Document for the Proposed Interstate Air Quality Rule (January 2004)." We expect that the actual designation of $PM_{2.5}$ and 8-hour ozone nonattainment areas will be based on 2001–2003 data. We plan to update our assessment to reflect the most recent data available at the time we issue the final rule.

[43] *See* section IV, Air Quality Modeling to Determine Future 8-hour Ozone and $PM_{2.5}$ Concentrations, for more detail on the approach summarized in this subsection.

[44] The EPA also considered the current and likely future nonattainment of the PM_{10} NAAQS and the 24-hour average $PM_{2.5}$ NAAQS. Only a small number of areas are presently experiencing PM_{10} exceedances, and all have approved SIPs that are expected to result in attainment through local control measures. Accordingly, we do not believe that interstate transport will be an important consideration for PM_{10} implementation in the period from 2010, or beyond, and therefore PM_{10} is not a subject of today's proposal. Few areas, all in the western U.S., presently have violations of the 24-hour average $PM_{2.5}$ NAAQS, and all of these are also violating the annual $PM_{2.5}$ NAAQS. We believe that to the extent interstate transport is contributing to nonattainment of the 24-hour $PM_{2.5}$ NAAQS, actions aimed at the broader problem of $PM_{2.5}$ nonattainment will correct any transport affecting 24-hour $PM_{2.5}$ also. The 24-hour $PM_{2.5}$ standard was not further assessed in our analysis for today's proposal.

upwind States would make this difficult or impossible. This information could then be used to determine whether upwind States should be expected to reduce their emissions.

a. Fine Particles

We conducted an assessment of the emissions reductions that States may need to include in nonattainment SIPs, and identified measures that could provide those emission reductions. We focused on the counties predicted to be nonattainment in the 2010 base case.

For our analysis of States' ability to attain the $PM_{2.5}$ standards, we developed a group of emissions reduction measures for SO_2, NO_X, direct $PM_{2.5}$, and volatile organic compounds (VOC) as a surrogate for measures that States would potentially implement prior to 2009 in an effort to reach attainment. The measures address a broad range of source types.[45] We analyzed the effect of applying this group of local controls in two different ways. First, we analyzed the impact of the emission controls on the immediate area in which they were applied. We applied the local control measures in three sample cities: Philadelphia, Birmingham, and Chicago. The group of local emissions controls was estimated to achieve ambient annual average $PM_{2.5}$ reductions ranging from about 0.5 $\mu g/m^3$ to about 0.9 $\mu g/m^3$, which was less than the amount needed to bring any of the three cities into attainment in 2010. The detailed results of this three-city analysis are provided in section IV.

Second, we analyzed the impact of applying the group of local controls to all 290 counties that are located in metropolitan areas in the eastern and central U.S. and that contain one or more of the counties projected to be nonattainment in 2010. This analysis was designed to assess whether applying local controls in upwind nonattainment areas, as States are expected to do, would significantly reduce transport to downwind States.

Based on this analysis, we concluded that for many $PM_{2.5}$ nonattainment areas it would be difficult, if not impossible, to reach attainment unless transport is reduced to a much greater degree and over a much broader regional area than by the simultaneous adoption of local controls within specific nonattainment areas. In addition, we found that much of the air quality improvement that did occur in downwind areas with this strategy was due to reductions in transported sulfate attributable to upwind SO_2 emissions. This indicates in particular that broader reductions in regionwide emissions of SO_2, from sources located both inside and outside potential nonattainment areas, would lead to sizable reductions in $PM_{2.5}$ concentrations.[46]

b. Eight-Hour Ozone

Our analyses suggest that NO_X emissions in upwind States will contribute a sizable fraction of the projected 8-hour ozone nonattainment problem in most nonattainment areas east of the continental divide in 2010 (even after the substantial improvements expected from implementing the NO_X SIP Call).[47] Our analysis also shows that additional highly cost-effective reductions of NO_X from power plants are available. Given continued widespread ozone nonattainment, we believe it is appropriate to require additional reductions in NO_X emissions that contribute to future nonattainment due to interstate transport.

Although numerous areas will attain the 8-hour ozone standards in the near term with existing controls, EPA believes that 15–20 areas east of the continental divide will need further emissions reductions (in some cases, large reductions) to attain the 8-hour standard. These areas have already adopted numerous measures to reduce 1-hour ozone levels.

We analyzed the effect of local measures on 8-hour ozone attainment. We conducted a preliminary scoping analysis in which hypothetical total NO_X and VOC emissions reductions of 25 percent were applied in all projected nonattainment areas east of the continental divide in 2010. Despite these substantial reductions, approximately eight areas were projected to have ozone levels exceeding the 8-hour standard. We believe that this hypothetical local control scenario is an indication that attaining the 8-hour standard will entail substantial cost in a number of areas, and that further regional reductions are warranted.

3. Assessment of Transported Pollutants and Precursors

a. Fine Particles

Section II provides a summary of our knowledge concerning the nature of $PM_{2.5}$ and its precursors. We have reviewed several studies that confirm the presence of interstate transport and identify many States as either sources or receptors. We have also conducted new analyses based on comparisons of newly available urban and rural ambient air quality data, source-receptor relationships, satellite observations, and wind trajectories. The details of these most recent analyses are contained in section V. These analyses show a wide range of transport patterns for $PM_{2.5}$. On different days in a year, transport follows a variety of paths, suggesting that to some extent emissions originating in one upwind State make some contribution to annual average $PM_{2.5}$ in many downwind States, even if the upwind State is a considerable distance from the downwind States.

These analyses further conclude that sources of SO_2 and NO_X emissions continue to play a strong role in transported $PM_{2.5}$. They suggest that nearly all the particulate sulfate in the cities we examined appears to result from transport from upwind sources outside the local urban area, while upwind and local contributions for the particle nitrate and carbonaceous components of $PM_{2.5}$ are likely to come from both upwind and local sources. These findings are consistent with what is known about the location of emissions sources for these pollutants and their atmospheric formation and transport mechanisms.

Based on a consideration of these findings regarding the origin and relative contribution of the major components to transported $PM_{2.5}$ in rural areas of the U.S. (see section II), as well as the results of modeling the air quality improvements of adopting highly cost-effective controls on SO_2 and NO_X emissions from EGUs in certain states east of the continental divide (see section IX), EPA proposes to base the $PM_{2.5}$ requirements on man-made SO_2 and NO_X emissions, and not other pollutants. As summarized below, current information related to sources and controls for the other components identified in transported $PM_{2.5}$ (carbonaceous particles, ammonium, and crustal materials) does not, at this time, provide an adequate basis for regulating the regional transport of emissions responsible for these $PM_{2.5}$ components.

Carbonaceous substances (organic compounds and soot) form a large

[45] See section IV and Tables IV–5, IV–6, and IV–7 for details on the analyses of local control measures.

[46] This particular type of analysis is not able to similarly distinguish the separate effects of upwind and local NO_X emissions reductions, but other types of analysis described in section V show the usefulness of upwind NO_X reductions in reducing $PM_{2.5}$ concentrations in nonattainment areas. detailed results of this three-city analysis are provided in section IV.

[47] Emissions reductions required under section 110(a)(2)(D) alone will not eliminate all transported ozone. Because areas with the highest interstate transport contributions tend to be located relatively close to major nonattainment areas in adjoining states, we expect that controls adopted for attainment purposes in upwind nonattainment areas will also reduce interstate ozone transport.

component of $PM_{2.5}$ in rural and urban areas of the East. As discussed in section II, the origins and effectiveness of alternative controls in reducing transported carbonaceous materials are particularly uncertain, and our ability to identify and quantify appropriate measures is quite limited. Some significant fraction may be of natural origin, including biogenic emissions and wildfires. The EPA has already issued national rules to reduce the most significant direct man-made source category of carbonaceous materials, the mobile source sector. These rules will provide some reduction of transported carbonaceous material, as well as significant reductions in urban areas. For other sources, the primary emissions of carbonaceous materials are not currently quantified with certainty. While controls for other man-made sources (*e.g.*, prescribed fires, home heating) may be of significance in developing local control approaches for $PM_{2.5}$ (*e.g.*, as in the analysis summarized in section III.D.2), their relative effectiveness in addressing regional transport is not well enough understood at this time. Substantial uncertainty also exists in attempting to model the formation processes and regional transport of secondary organic particles deriving from biogenic or man-made emissions of organic precursors. To the extent that the production of regional secondary organic particles is related to ozone formation processes, regional NO_X reductions could provide some additional benefit. Measures adopted to reduce man-made VOC emissions should also tend to reduce secondary organic $PM_{2.5}$.

We also do not feel it is necessary or appropriate at this time to attempt to reduce the ammonium portion of $PM_{2.5}$ through regional ammonium controls. As indicated in section II, it is reasonable to expect that simultaneous significant reductions in regional SO_2 and NO_X emissions will also result in a decrease in particulate phase ammonium, while reducing the relative effectiveness of additional ammonia reductions. The alternative of reducing regional ammonia loadings in place of SO_2 and NO_X controls is unattractive because it increases the acidity of $PM_{2.5}$ and of deposition, and is less effective at reducing total loadings of fine particles. Further, while local ammonia reductions might reduce nitrates in some locations, the peak nitrate concentrations in the East come in the wintertime, when ammonia emissions are lowest. As noted in section II, in such circumstances, reductions in NO_X are likely to be effective in reducing nitrates. Finally, the strength and location of ammonia emissions sources, including agricultural operations, are uncertain, and the costs and net effectiveness of alternative regional-scale ammonia controls from a variety of rural and urban sources cannot be adequately quantified. The EPA continues to support research on ammonia emissions, controls and atmospheric processes, which should inform State and local control agency decisions on ammonia controls in the future.

We are proposing not to address direct emissions of crustal material because, among other things, the amount of crustal material is generally a small fraction of total $PM_{2.5}$ in nonattainment areas, crustal material does not appear to be much involved in regional-scale transport on an annual basis, and we face uncertainties in inventories and control costs for crustal material. While most crustal material on a regional scale is likely derived from soils, a small but uncertain fraction of certain components of combustion emissions are classified as "crustal" or "soil derived." As a practical matter, we expect that implementation of today's proposed controls to reduce SO_2 and NO_X from coal-fired EGUs would have co-benefits in reducing those direct emissions of $PM_{2.5}$ that are now classified as crustal material.

The proposed decisions to focus on SO_2 and NO_X reductions for addressing interstate pollution transport should not preclude controls related to carbonaceous particles, ammonium, or other significant $PM_{2.5}$ sources on a local basis, where these can be adopted cost effectively in local $PM_{2.5}$ control plans. We welcome comment on the choice to not regulate the above components of transported $PM_{2.5}$, including further information regarding the cost effectiveness of controls.

b. Ozone

Section II summarizes our knowledge regarding ozone and its precursors. We continue to rely on the assessment of ozone transport made in great depth by the OTAG in the mid-1990s. As indicated in the NO_X SIP Call proposal, the OTAG Regional and Urban Scale Modeling and Air Quality Analysis Work Groups reached the following conclusions:

- Regional NO_X emissions reductions are effective in producing ozone benefits; the more NO_X reduced, the greater the benefit.
- Controls for VOC are effective in reducing ozone locally and are most advantageous to urban nonattainment areas. (62 FR 60320, November 7, 1997)

We reaffirm this conclusion in this rulemaking, and propose to address only NO_X emissions for the purpose of reducing interstate ozone transport.

4. Role of Interstate Transport in Future Nonattainment

a. Fine Particles

For $PM_{2.5}$, we used a "zero-out" approach to assess $PM_{2.5}$ transport coming from each of the 41 States that lie at least partly east of the continental divide, *i.e.*, New Mexico northwards to Montana and all States east of those. Our zero-out approach consisted of air quality model runs for each State, both with and without each State's man-made SO_2 and NO_X emissions. We then compared the predicted downwind concentrations in the 2010 base case, which included the State's SO_2 and NO_X emissions, to the "zero-out" case which excluded all of the State's man-made SO_2 and NO_X emissions. From these results, we were able to evaluate the impact of, for example, Ohio's total man-made SO_2 and NO_X emissions on each projected downwind nonattainment county in 2010. Using the results of this modeling, we identified States as significantly contributing (before considering costs) to downwind nonattainment based on the predicted change in the $PM_{2.5}$ concentration in the downwind nonattainment area which receives the largest impact.

As detailed in section VI below, EPA's modeling indicates a wide range of maximum downwind nonattainment impacts from the 41 States. The largest contribution is from Ohio on Hancock County, WV where the annual $PM_{2.5}$ impact is 1.90 $\mu g/m^3$. Rhode Island has the lowest maximum contribution to a downwind nonattainment area, registering a maximum impact of 0.01 $\mu g/m^3$ on New Haven, Connecticut.

We have considered what level of air quality impact should be regarded as significant (without taking costs into account), and believe that the level should be a small fraction of the annual $PM_{2.5}$ NAAQS of 15.0 $\mu g/m^3$. Our reasoning is based on two factors. First, as EPA determined in 1997 when we established the $PM_{2.5}$ NAAQS, there are significant public health impacts associated with ambient $PM_{2.5}$, even at relatively low levels. By the same token, as summarized earlier, EPA's modeling indicates that at least some nonattainment areas will find it difficult or impossible to attain the standards without reductions in upwind emissions. In combination, these factors suggest a relatively low value for the

$PM_{2.5}$ transport contribution threshold is appropriate.

Second, our analysis of "base case" $PM_{2.5}$ transport shows that many upwind States contribute to concentrations in each of the areas predicted to be nonattainment in 2010. This "collective contribution" is a feature of the $PM_{2.5}$ transport problem, in part because the annual nature of the NAAQS means that wind patterns throughout the year—rather than wind patterns during one season of the year or on a few worst days during the year—play a role in determining how States contribute to each other. The implication is that to address the transport affecting a given nonattainment area, many upwind States must reduce their emissions, even though their individual contributions may be relatively small. By the same token, as summarized earlier, EPA's modeling indicates that at least some nonattainment areas will find it difficult or impossible to attain the standards without reductions in upwind emissions. In combination, these factors suggest a relatively low value for the $PM_{2.5}$ transport contribution threshold is appropriate.

We adopted a similar approach for determining the significance level for ozone transport in the NO_X SIP Call rulemaking, and the D.C. Circuit viewed this approach as reasonable when the Court generally upheld the NO_X SIP Call. The Court acknowledged that EPA had set a relatively low hurdle for States to pass the air quality component (and thus be considered to contribute significantly, depending on costs): "EPA's design was to have a lot of States make what it considered modest NO_X reductions. * * * " *See Michigan* v. *EPA,* 213 F.3d 663(D.C. Cir. 2000), *cert. denied,* 532 U.S. 904 (2001). Indeed, the Court intimated that EPA could have established an even lower hurdle for States to pass the air quality component:

> EPA has determined that ozone has *some* adverse health effects—however slight—at every level [citing National Ambient Air Quality Standards for Ozone, 62 FR 38856 (1997)]. Without consideration of cost it is hard to see why *any* ozone-creating emissions should not be regarded as fatally "significant" under section 110(a)(2)(D)(i)(I)." 213 F.3d at 678 (emphasis in original).

We believe the same approach should apply in the case of $PM_{2.5}$ transport.

In applying this approach, we first considered a significance level of 0.10 $\mu g/m^3$. This is a small level, which is consistent with the factors described. Further, an increment of this size in the annual average $PM_{2.5}$ concentration is the smallest one that can make the difference between compliance and violation of the NAAQS for an area very near the NAAQS, due to the treatment of significant digits and rounding in the definition of the NAAQS. Because the $PM_{2.5}$ NAAQS is 15.0 $\mu g/m^3$ (three significant figures), a concentration after rounding of 15.1 $\mu g/m^3$ would be a violation.[48]

On the other hand, we then considered that the air quality forecasts we have conducted in assessing future air quality impacts have, of necessity, been based on modeling, not monitoring data. In evaluating such results, we believe it is, on balance, more appropriate to adopt a small percentage value of the standard level, rather than absolute number derived from monitoring considerations. A percentage amount that is close to the value derived from the monitoring level described above is 1 percent. We therefore propose to adopt an annual $PM_{2.5}$ significance level equal to 1 percent of the standard. We believe that contributions equal to or greater than 0.15 $\mu g/m^3$ would reflect a reasonable threshold for determining significant levels of interstate transport.

Applying the proposed cutoff of 0.15 $\mu g/m^3$ or higher to the results of the transport impact assessment identifies SO_2 and NO_X emissions in 28 States and the District of Columbia as contributing significantly (before considering costs) to nonattainment in another State. These States, with their maximum downwind $PM_{2.5}$ contributions, are listed in section V, Table V–5.

Although we are proposing to use 0.15 $\mu g/m^3$ as the air quality criteria, we have also analyzed the effects of using 0.10 $\mu g/m^3$. Based on our current modeling, two additional states, Oklahoma and North Dakota, would be included if we were to adopt 0.10 $\mu g/m^3$ as the air quality criterion. Thus, today's proposal includes the State EGU budgets that would apply if these two states were included under the final rule. The EPA requests comments on the appropriate geographic scope of this proposal and the merits of the proposed 0.15 $\mu g/m^3$ threshold level as indicating a potentially significant effect of air quality in nonattainment areas in neighboring states. We request comments on the use of higher and lower thresholds for this purpose.

b. Eight-Hour Ozone

In assessing the role of interstate transport to 8-hour ozone nonattainment, we have followed the approach used in the NO_X SIP Call, but have used an updated model and updated inputs that reflect current requirements (including the NO_X SIP Call itself).[49] Using updated contribution results, we rely on the same contribution indicators, or metrics, that were used to make findings in the NO_X SIP Call. Section V and the air quality technical support document present the 8-hour ozone transport analysis and findings in detail.

In general, we found a range in how much transport from each upwind State contributes to 2010 nonattainment in downwind States. The EPA's modeling indicates from 22 to 96 percent of the ozone problem is due to transport, depending on the area.

Based on the same metrics employed in the NO_X SIP Call, we have concluded that, even with reductions from the NO_X SIP Call and other control measures that will reduce NO_X and VOC emissions, interstate transport of NO_X from 25 States and the District of Columbia will contribute significantly to downwind 8-hour ozone nonattainment in 2010. These States are listed in Table V–2. We are deferring findings for Texas, Oklahoma, Kansas, Nebraska, South Dakota, and North Dakota, which at this time cannot be assessed on the same basis as States to the east because they are only partially included in the modeling domain. We intend to conduct additional modeling for these six States using a larger modeling domain, and may propose action on them based on that modeling in a supplemental proposal.

5. Assessment of Potential Emissions Reductions

Today's proposal generally follows the statutory interpretation and approach under section 110(a)(2)(D) developed in the NO_X SIP Call rulemaking. Under this interpretation, the emissions in each upwind State that contribute significantly to nonattainment are identified as being those emissions which can be eliminated through highly cost-effective controls.

Section 110(a) requires upwind States to eliminate emissions that contribute significantly to nonattainment

[48] An area with a reported rounded concentration of 15.0 $\mu g/m^3$ would have actual air quality somewhere in the range of 14.95 to 15.04 $\mu g/m^3$. An increase of 0.10 $\mu g/m^3$ would make the rounded concentration equal 15.1 $\mu g/m^3$, which would constitute an exceedance, no matter where in the 14.95 to 15.04 $\mu g/m^3$ range the concentration fell originally. This is not the case with any increase less than 0.10 $\mu g/m^3$. For example, an increase of 0.09 $\mu g/m^3$ when added to 14.95 $\mu g/m^3$ and then rounded would result in a NAAQS compliance value of 15.0 $\mu g/m^3$, a passing result.

[49] The modeling for today's proposal, and the proposal itself fulfills EPA's commitment in the 1998 NO_X SIP Call final rule to reevaluate by 2007. *See* 63 FR 57399; October 27, 1998.

downwind, and to do so through a SIP revision that must be submitted to EPA within 3 years of issuance of revised NAAQS. In addition, States are required to submit SIPs that provide for attainment in nonattainment areas no later than 3 years after designation.

Through these provisions, the CAA places the responsibility for controls needed to assure attainment on both upwind States and their sources, and on local sources of emissions. The CAA does not specify the relative shares of the burden that each should carry, but section 110(a)(2)(D) clearly mandates that upwind States reduce those emissions that contribute significantly to downwind nonattainment. Moreover, as a matter of broad policy, even if an area could attain the NAAQS through technically feasible, but costly, local controls alone, some consideration needs to be given to a reasonable balance between regional and local controls to reach attainment. In the absence of regional controls on upwind sources, downwind States would be forced to obtain greater emissions reductions, and incur greater costs, to offset the transported pollution from upwind sources.

For the $PM_{2.5}$ and 8-hour ozone NAAQS, our air quality modeling shows attainment with local controls alone would be difficult or impossible for many areas. Our analysis in section VI shows that substantial regional reductions in SO_2 and NO_X emissions from EGUs are available at costs that are well within the levels of historically adopted measures. An attainment strategy that relies on a combination of local controls and regional EGU controls is a more equitable and therefore a more reasonable approach than a strategy that relies solely on local controls.

a. Identifying Highly Cost-Effective Emissions Reductions

As the second step in the two-step process for determining the amount of significant contribution, we must determine the amount of emissions that may be eliminated through highly cost-effective controls. Today we are proposing to retain the concept of highly cost-effective controls as developed and used in the NO_X SIP Call, in which we determined such controls by comparing the cost of recently required controls, and to apply it to the SO_2 and NO_X precursors of $PM_{2.5}$ and 8-hour ozone nonattainment.

For today's proposal, EPA independently evaluated the cost effectiveness of strategies to reduce SO_2 and NO_X to address $PM_{2.5}$ and ozone nonattainment. We developed criteria for highly cost-effective amounts through: (1) comparison to the average cost effectiveness of other regulatory actions and (2) comparison to the marginal cost effectiveness of other regulatory actions. These ranges indicate cost-effective controls. The EPA believes that controls with costs towards the low end of the range may be considered to be highly cost effective because they are self-evidently more cost effective than most other controls in the range. We also considered other factors. Our approach to the cost-effectiveness element of significant contribution and the results of our analysis are presented in section VI.

The other factors we have considered include the applicability, performance, and reliability of different types of pollution control technologies for different types of sources; the downwind impacts of the level of control that is identified as highly cost effective; and other implementation costs of a regulatory program for any particular group of sources. We also consider some of these same factors in determining the time period over which controls should be installed. Depending on the type of controls we view as cost effective, we must take into account the time it would take to design, engineer, and install the controls, as well as the time period that a source would need to obtain the necessary financing. These various factors, including engineering and financial factors, are discussed in section VI. We may also consider whether emissions from a particular source category will be controlled under an upcoming regulation (a MACT standard, for example).

Today's action proposes emissions reductions requirements based on highly cost-effective emissions reductions obtainable from EGUs. Section VI explains the proposed requirements.

b. Timing for Submission of Transport SIPs

We are proposing today to require that $PM_{2.5}$ and 8-hour ozone transport SIPs be submitted, under CAA section 110(a)(1), as soon as practicable, but not later than 18 months from the date of promulgation of this rule. Based on the experience of States in developing plans to respond to the NO_X SIP Call, we believe this is a reasonable amount of time. The NO_X SIP Call required States to submit SIPs within 12 months of the final rule, a period within the maximum 18 months allowed under section 110(k)(5) governing States' responses to SIP calls. The 12-month period was reasonable for the NO_X SIP Call given the focus on a single pollutant, NO_X, and the attainment deadlines facing downwind 1-hour ozone nonattainment areas. Since today's proposal requires affected States to control both SO_2 and NO_X emissions, and to do so for the purpose of addressing both the $PM_{2.5}$ and 8-hour ozone NAAQS, we believe it is reasonable to allow affected States more time than was allotted in the NO_X SIP Call to develop and submit transport SIPs. Since we plan to finalize this rule no later than mid-2005, SIP submittals would be due no later than the end of 2006. Under this schedule, upwind States' transport SIPs would be due before the downwind States' $PM_{2.5}$ and 8-hour ozone nonattainment SIPs, under CAA section 172(b). We expect that the downwind States' 8-hour ozone nonattainment area SIPs will be due by May 2007, and their nonattainment SIPs for $PM_{2.5}$ by January 2008.[50] As explained in section VII below, today's proposed requirement that the upwind States submit the transport SIP revisions even before the downwind States submit nonattainment SIPs is consistent with the CAA SIP submittal sequence, will provide health and environmental benefits, and will assist the downwind States in their attainment demonstration planning.

c. Timing for Achieving Emissions Reductions

As discussed in section VI, engineering and financial factors suggest that only a portion of the emissions reductions that EPA considers highly cost effective can be achieved by January 1, 2010. To ensure timely protection of public health, while taking into account these considerations, we are proposing to implement highly cost-effective reductions in two phases, with a Phase I compliance date of January 1, 2010, and a Phase II compliance date of January 1, 2015.

Based on EPA's analysis, we believe that a regional emissions cap on SO_2 of 3.9 million tons together with a NO_X emissions cap of 1.6 million tons is achievable by January 1, 2010, and therefore we are proposing these limits as the Phase I requirements.[51] The EPA believes the remaining highly cost-effective SO_2 and NO_X emissions reductions can be achieved by January 1, 2015, and will be helpful to areas with $PM_{2.5}$ or 8-hour ozone attainment dates approaching 2015. The EGU caps

[50] The actual dates will be determined by relevant provisions in the CAA and EPA's interpretation of these provisions published in upcoming implementation rules for the $PM_{2.5}$ and 8-hour ozone NAAQS.

[51] Because Connecticut is affected only by the 8-hour ozone findings, NO_X emissions reductions are not necessary until the ozone season. Therefore, for Connecticut only, EPA is proposing a Phase I NO_X reduction compliance date of May 1, 2010.

in the proposed control region would be lowered in the second phase to 2.7 million tons for SO_2 and 1.3 million tons for NO_X. The current 28-state[52] emissions, baseline emissions in 2010 and 2015 and proposed regional emissions caps are shown in Table III–1.

TABLE III–1.—SO_2 AND NO_X REGIONWIDE EMISSIONS REDUCTIONS AND EMISSIONS CAPS

	2002 Emissions (tons)	2010 (tons)		2015 (tons)	
		Baseline emissions	Cap	Baseline emissions	Cap
SO_2	9.4M	9.0M	3.9M	8.3M	2.7M
NO_X	3.7M	3.1M	1.6M	3.2M	1.3M

We derived these amounts as follows: The SO_2 emissions limitations correspond to 65 percent of the affected States' title IV allowances in 2015, and 50 percent in 2010. The NO_X emissions limitations correspond to the sum of the affected States' historic heat input amounts, multiplied by an emission rate of 0.125 mmBtu for 2015 and 0.15 mmBtu for 2010. Historic heat input is derived as the highest annual heat input during 1999–2002. We are proposing that these regionwide limits correspond to costs that meet the highly cost-effective criteria.

Further, EPA proposes to apportion these regionwide amounts to the individual States in the region as follows: For SO_2, EPA proposes to apportion the regionwide amounts to the individual States in the region in proportion to their title IV allocations. This would amount to requiring reductions in the amount of 65 percent of each affected State's title IV allocations for 2015, and 50 percent for 2010. The EPA is considering requiring an adjustment to these amounts to account for the fact that the utility industry has changed since the title IV allocation formulae were developed. For NO_X, EPA proposes to apportion the regionwide amounts to the individual States in the region in proportion to their historic heat input, determined as the average of several years of heat input.

d. Compliance Approaches and Statewide Emissions Budgets

Today's proposal affects 28 upwind States and the District of Columbia for the purpose of addressing $PM_{2.5}$ transport, and 25 States and the District of Columbia for the purpose of addressing ozone transport. For States required to reduce NO_X emissions to address 8-hour ozone transport, the NO_X reductions must be implemented at least during the ozone season. For States required to reduce SO_2 and NO_X emissions to address $PM_{2.5}$ transport, the NO_X and SO_2 reductions must be achieved annually. For States affected for both $PM_{2.5}$ and ozone, EPA is proposing that compliance with the $PM_{2.5}$-related annual emissions reduction requirement be deemed sufficient for compliance with the seasonal ozone-related emissions reduction requirement.

The EPA also wants to streamline potentially overlapping compliance requirements between the existing NO_X SIP Call and today's proposed action, while ensuring that the ozone benefits of the NO_X SIP Call are not jeopardized. The EPA is proposing that States may choose to recognize compliance with the more stringent annual NO_X reduction requirements contained in today's rulemaking as satisfying the original NO_X SIP Call seasonal reduction requirements for sources that States cover under both the NO_X SIP Call and today's proposal.

We are proposing to calculate the amount of required reductions on the basis of controls available for EGUs. We believe these EGU reductions represent the most cost-effective reductions available. In 2010, considering other controls that will be in place, but not assuming a rule to address transported pollution is implemented, EGUs are projected to emit approximately one-quarter of the total man-made NO_X emissions in 2010 and two-thirds of the man-made SO_2 emissions in the region proposed for reductions in today's rulemaking. Extensive information exists indicating that highly cost-effective controls are available for achieving significant reductions in NO_X and SO_2 emissions from the EGU sector.

We are proposing that (as under the NO_X SIP Call) States obtaining reductions from EGUs to comply with today's proposal must cap their EGUs at levels that will assure the required reductions. In addition, today's action proposes an approach which permits the use of title IV SO_2 allowances at discounted levels that provide for a planned transition toward accomplishing the objectives of the interstate air quality rule.

Based on our experience in the NO_X SIP Call, we anticipate that States will choose to require EGUs to participate in the cap and trade programs administered by EPA. If States choose to participate in the cap and trade programs, States must adopt the model cap and trade programs, described in section VIII. The cap and trade programs will create incentives for EGUs to reduce SO_2 and NO_X emissions starting no later than 2010, and probably somewhat earlier, and continuing to 2015 and beyond. The model cap and trade programs are designed to satisfy all the SO_2 and NO_X emissions reduction requirements proposed in today's rule.

If a State imposes the full amount of SO_2 and NO_X emissions reductions on EGUs that EPA has deemed highly cost effective, we are taking comment on whether this approach to compliance with the interstate air quality rule by affected EGUs in affected States would satisfy for those sources the Best Available Retrofit Technology (BART) requirements of the CAA. We are further soliciting comment, for the circumstances just described, on whether compliance through participation in a regionwide or statewide cap and trade program, rather than source-specific emissions limits, could satisfy the BART requirements for those sources.

States that choose to obtain some of the required SO2 or NO_X reductions from non-EGU sources must adopt control measures for those other sources. To assure accurate accounting of emissions reductions, these States will have to establish sector-specific baseline emission inventories for 2010 and 2015. These States will also have to measure projected emissions reductions from adopted measures from these baselines. The sector-specific baseline inventory minus the amount of

[52] Excludes emissions from Connecticut.

reduction the State chooses to obtain from that sector is the sector budget for those sources. The SIP must contain a projection showing that compliance with the adopted measure(s) for that sector will ensure that emissions from the sector will meet the sector budget.

E. Request for Comment on Potential Applicability to Regional Haze

We believe that the emissions reductions that would result from today's proposed rulemaking would help the States in making substantial progress towards meeting the goals and requirements of the Regional Haze rule in the Eastern U.S. As a result of the predicted emissions reductions, we anticipate that visibility would improve in Class I areas in this region, including in areas such as the Great Smoky and Shenandoah National Parks. We request comment on the extent to which the reductions achieved by these rules would, for States covered by the IAQR, satisfy the first long term strategy for regional haze, which is required to achieve reasonable progress towards the national visibility goal by 2018.

We also request comment on whether the cap and trade approach proposed in this rulemaking is a suitable mechanism that could be expanded to help other States meet their regional haze obligations under the CAA. If we were to propose this approach, we would address this further in a supplemental notice and we would need to amend our Regional Haze rule to specify that, in establishing a reasonable progress goal for any Class I area as required by CAA section 169A and our rule, the State would need to submit a SIP revision that, at a minimum, would enable the State to participate in a cap and trade program that reflects a rate of progress based on specified levels of SO_2 and NO_X reductions that we find are reasonable in light of the natural visibility goal that Congress established in 1977. Such an approach could be proposed to apply to areas identified in our final Regional Haze rule (64 FR 35714, July 1, 1999) as having emissions that may reasonably be anticipated to cause or contribute to an impairment of visibility in at least one Class I area, to reduce those emissions. We note that, under such an approach, we could consider two separate NO_X emission levels and two separate cap and trade zones for NO_X. States included on the basis of their contribution to either ozone or $PM_{2.5}$ nonattainment would be in one zone and would need to meet the NO_X emission reduction requirements discussed elsewhere in this action. States included only on the basis of needing to achieve reasonable progress goals would be in a separate zone and would need to meet a level specifically designed to address that issue. We request comment on what emissions levels should be considered for SO_2 and NO_X if we were to pursue such an approach. We also request comment on how such an approach could be integrated with and combine the efforts of Regional Planning Organizations that are working to address regional haze.

F. How Will the Interstate Air Quality Rule Apply to the Federally Recognized Tribes?

The Tribal Authority Rule (TAR) (40 CFR part 49), which implements section 301(d) of the CAA, gives Tribes the option of developing CAA programs, including Tribal Implementation Plans (TIPs). However, unlike States, Tribes are not required to develop implementation plans. Specifically, the TAR, adopted in 1998, provides for the Tribes to be treated in the same manner as a State in implementing sections of the CAA. The EPA determined in the TAR that it was appropriate to treat Tribes in a manner similar to a State in all aspects except specific plan submittal and implementation deadlines for NAAQS-related requirements, including, but not limited to, such deadlines in CAA sections 110(a)(1), 172(a)(2), 182, 187, and 191.[53]

In addition, the TAR also indicates that section 110(a)(2)(d) applies to the Tribes. This provision of the Act requires EPA to ensure that SIPs and TIPs ensure that their sources do not contribute significantly to nonattainment downwind. In fact, Tribes generally have few emissions sources and thus air quality problems in Indian country are generally created by transport into Tribal lands. Specifically, in the February 12, 1998 preamble to the Tribal Air Rule we stated:

> EPA notes that several provisions of the CAA are designed to address cross-boundary air impacts. EPA is finalizing its proposed approach that the CAA protections against interstate pollutant transport apply with equal force to States and Tribes. Thus EPA is taking the position that the prohibitions and authority contained in sections 110(a)(2)(D) and 126 of the CAA apply to Tribes in the same manner as States. As EPA noted in the preamble to its proposed rule, section 110(a)(2)(D), among other things, requires States to include provisions in their SIPs that prohibit any emissions activity within the State from significantly contributing to nonattainment * * * In addition, section 126 authorizes any State or Tribe to petition EPA to enforce these prohibitions against a State containing an allegedly offending source or group of sources. See 63 FR 7262, 59 FR 43960–43961.

Because the Tribes, like the States are our regulatory partners, in developing the interstate air quality rule we want to ensure that the Tribes' air quality and sovereignty are protected. Thus, we are exploring areas in the rule development where Tribes will be impacted. One area, in particular, is in the establishment of emissions reduction requirements and budgets. We are not aware of the presence of any EGUs on tribal lands located in the States for which EPA has conducted air quality modeling for today's proposal. Although, it is possible that EGUs may locate in Indian country in the future. We are requesting comment on whether and how to apply any emissions reductions or budget requirements to the Tribes, as well as comments on other areas of the rule that will impact the Tribes.

IV. Air Quality Modeling To Determine Future 8-Hour Ozone and $PM_{2.5}$ Concentrations

A. Introduction

In this section, we describe the air quality modeling performed to support today's proposal. We used air quality modeling primarily to quantify the impacts of SO_2 and NO_x emissions from upwind States on downwind annual average $PM_{2.5}$ concentrations, and the impacts of NO_x emissions from upwind States on downwind 8-hour ozone concentrations.

This section includes information on the air quality models applied in support of the proposed rule, the meteorological and emissions inputs to these models, the evaluation of the air quality models compared to measured concentrations, and the procedures for projecting ozone and $PM_{2.5}$ concentrations for future year scenarios. We also present the results of modeling locally applied control measures designed to reduce concentrations of $PM_{2.5}$ in projected nonattainment areas. The Air Quality Modeling Technical Support Document (AQMTSD) contains more detailed information on the air quality modeling aspects of this rule.[54] Updates made between the proposed rule and the final rule to components of the ozone and PM modeling platform will be made public in a Notice of Data Availability.

[53] *See* 40 CFR 49.4(a).

[54] "Air Quality Modeling Technical Support Document for the Proposed Interstate Air Quality Rule (January 2004)" can be obtained from the docket for today's proposed rule: OAR–2003–0053.

B. Ambient 8-Hour Ozone and Annual Average $PM_{2.5}$ Design Values

1. 8-Hour Ozone Design Values

Future year levels of air quality are estimated by applying relative changes in model-predicted ozone to current measurements of ambient ozone data. Current measurements of ambient ozone data come from monitoring networks consisting of more than one thousand monitors located across the country. The monitors are sited according to the spatial and temporal nature of ozone, and to best represent the actual air quality in the United States. More information on the monitoring network used to collect current measurements of ambient ozone is in the Air Quality Data Analysis Technical Support Document.[55]

In analyzing the ozone across the United States, the raw monitoring data must be processed into a form pertinent for useful interpretations. For this action, the ozone data have been processed consistent with the formats associated with the NAAQS for ozone. The resulting estimates are used to indicate the level of air quality relative to the NAAQS. For ozone air quality indicators, we developed estimates for the 8-hour ozone standard. The level of the 8-hour ozone NAAQS is 0.08 ppm. The 8-hour ozone standard is not met if the 3-year average of the annual 4th highest daily maximum 8-hour ozone concentration is greater than 0.08 ppm (0.085 is rounded up). This 3-year average is called the annual standard design value. As described below, the approach for forecasting future ozone design values involved the projection of 2000–2002 ambient design values to the various future year emissions scenarios analyzed for today's proposed rule. These data were obtained from EPA's Air Quality System (AQS) on August 11, 2003. A more detailed description of design values is in the Air Quality Data Analysis Technical Support Document. A list of the 2000–2002 Design Values is available at *http://www.epa.gov/airtrends/values.html.*

2. Annual Average $PM_{2.5}$ Design Values

Future year levels of air quality are estimated by applying relative changes in model predicted $PM_{2.5}$ to current measurements of ambient $PM_{2.5}$ data. Current measurements of ambient $PM_{2.5}$ data come from monitoring networks consisting of more than one thousand monitors located across the country. The monitors are sited according to the spatial and temporal nature of $PM_{2.5}$ and to best represent the actual air quality in the United States. More information on the monitoring network used to collect current measurements of ambient $PM_{2.5}$ is in the Air Quality Data Analysis Technical Support Document.

In analyzing the $PM_{2.5}$ data across the United States, the raw monitoring data must be processed into a form pertinent for useful interpretations. For this action, the $PM_{2.5}$ data have been processed consistent with the formats associated with the NAAQS for $PM_{2.5}$. The resulting estimates are used to indicate the level of air quality relative to the NAAQS. For $PM_{2.5}$, the annual standard is met when the 3-year average of the annual mean concentration is 15.0 $\mu g/m^3$ or less. The 3-year average annual mean concentration is computed at each site by averaging the daily Federal Reference Method (FRM) samples taken each quarter, averaging these quarterly averages to obtain an annual average, and then averaging the three annual averages. The 3-year average annual mean concentration is also called the annual standard design value. As described below, the approach for forecasting future $PM_{2.5}$ design values involved the projection of 1999–2001 and 2000–2002 ambient design values to the various future year emissions scenarios analyzed for today's proposed rule. These data were obtained from EPA's Air Quality System (AQS) on July 9, 2003. A more detailed description of design values is in the Air Quality Data Analysis Technical Support Document. A list of the 1999–2001 and 2000–2002 Design Values is available at *http://www.epa.gov/airtrends/values.html.*

C. Emissions Inventories

1. Introduction

In order to support the air quality modeling analyses for the proposed rule, emission inventories were developed for the 48 contiguous States and the District of Columbia. These inventories were developed for a 2001 base year to reflect current emissions and for future baseline scenarios for years 2010 and 2015. The 2001 base year and 2010 and 2015 future base case inventories were in large part derived from a 1996 base year inventory and projections of that inventory to 2007 and 2020 as developed for previous EPA rulemakings for Heavy Duty Diesel Engines (HDDE) (*http://www.epa.gov/otaq/models/hd2007/r00020.pdf*) and Land-based Non-road Diesel Engines (LNDE) (*http://www.epa.gov/nonroad/454r03009.pdf*). The inventories were prepared at the county level for on-road vehicles, non-road engines, and area sources. Emissions for EGUs and industrial and commercial sources (non-EGUs) were prepared as individual point sources. The inventories contain both annual and typical summer season day emissions for the following pollutants: oxides of nitrogen (NO_X); volatile organic compounds (VOC); carbon monoxide (CO); sulfur dioxide (SO_2); direct particulate matter with an aerodynamic diameter less than 10 micrometers (PM_{10}) and less than 2.5 micrometers ($PM_{2.5}$); and ammonia (NH_3). Additional information on the development of the emissions inventories for air quality modeling and State total emissions by sector and by pollutant for each scenario are provided in the AQMTSD.

2. Overview of 2001 Base Year Emissions Inventory

Emissions inventory inputs representing the year 2001 were developed to provide a base year for forecasting future air quality, as described below in section IV.D. for ozone and section IV.E. for $PM_{2.5}$. Because the complete 2001 National Emissions Inventory (NEI) and future year projections consistent with that NEI were not available in a form suitable for air quality modeling when needed for this analysis, the following approach was used to develop a reasonably representative "proxy" inventory for 2001 in model-ready form that retained the same consistency with the existing future year projected inventories as the 1996 model-ready inventory that was used as the basis for those projected inventories.

The EPA had available model-ready emissions input files for a 1996 Base Year and a 2010 Base Case from a previous analysis. In addition, robust NEI estimates were available for 2001 for three of the six man-made emissions sectors: EGUs; on-road vehicles; and non-road engines. For the EGU sector, State-level emissions totals from the NEI 2001 were divided by similar totals from the 1996 modeling inventory to create a set of 1996 to 2001 adjustment ratios. Ratios were developed for each State and pollutant. These ratios were applied to the model-ready 1996 EGU emissions file to produce the 2001 EGU emissions file.

The NEI 2001 emissions estimates for the on-road vehicles and non-road engines sectors were available from the MOBILE6 and NONROAD2002 models, respectively. Because both of these models were updates of the versions used to produce the existing 1996 model-ready emissions files and their associated projection year files, a

[55] "Air Quality Data Analysis Technical Support Document for the Proposed Interstate Air Quality Rule (January 2004)" can be obtained from the docket for today's proposed rule: OAR–2003–0053.

slightly different approach than that used for the EGUs was used to adjust the 1996 model-ready files to produce files for 2001.

The updated MOBILE6 and NONROAD2002 models were used to develop 1996 emissions estimates that were consistent with the 2001 NEI estimates. A set of 1996–to–2001 adjustment ratios were then created by dividing State-level total emissions for each pollutant for 2001 by the corresponding consistent 1996 emissions. These adjustment ratios were then multiplied by the gridded model-ready 1996 emissions for these two sectors to produce model-ready files for 2001. These model-ready 2001 files, therefore, maintain consistency with the future year projection files that were based on the older emission model versions but also capture the effects of the 1996 to 2001 emission changes as indicated by the latest versions of the two emissions models.

Consistent estimates of emissions for the 2001 Base Year were not available at the time modeling was begun for two other emission sectors: non-EGU point sources and area sources. For these two sectors, linear interpolations were performed between the gridded 1996 emissions and the gridded 2010 Base Case emissions to produce 2001 gridded emissions files. These interpolations were done separately for each of the two sectors, for each grid cell, for each pollutant. As the 2010 Base Case inventory was itself a projection from the 1996 inventory, this approach maintained consistency of methods and assumptions between the 2001 and 2010 emissions files.

3. Overview of the 2010 and 2015 Base Case Emissions Inventories

The future base case scenarios generally represent predicted emissions in the absence of any further controls beyond those State, local, and Federal measures already promulgated plus other significant measures expected to be promulgated before the final rule from today's proposal. Any additional local control programs which may be necessary for areas to attain the annual $PM_{2.5}$ NAAQS and the ozone NAAQS are not included in the future base case projections. The future base case scenarios do reflect projected economic growth, as described in the AQMTSD.

Specifically, the future base case scenarios include the effects of the LNDE as proposed, the HDDE standards, the Tier 2 tailpipe standards, the NO_X SIP Call as remanded (excludes controls in Georgia and Missouri), and Reasonably Available Control Techniques (RACT) for NO_X in 1-hour ozone nonattainment areas. Adjustments were also made to the non-road sector inventories to include the effects of the Large Spark Ignition and Recreational Vehicle rules; and to the non-EGU sector inventories to include the SO_2 and particulate matter co-benefit effects of the proposed Maximum Achievable Control Technology (MACT) standard for Industrial Boilers and Process Heaters. The future base case scenarios do not include the NO_X co-benefit effects of proposed MACT regulations for Gas Turbines or stationary Reciprocating Internal Combustion Engines, which we estimate to be small compared to the overall inventory; or the effects of NO_X RACT in 8-hour ozone nonattainment areas, because these areas have not yet been designated.

4. Procedures for Development of Emission Inventories

a. Development of Emissions Inventories for Electric Generating Units

As stated above, the 2001 Base Year inventory for the EGU sector was developed by applying State-level adjustment ratios of 2001 NEI[56] emissions to 1996 emissions for the EGU sector to the existing model-ready 1996 EGU file. Adjustments were thus made in the modeling file to account for emissions reductions that had occurred between 1996 and 2001, but at an aggregated State-level, rather than for each individual source. Future year 2010 and 2015 Base Case EGU emissions used for the air quality modeling runs that predicted ozone and $PM_{2.5}$ nonattainment status were obtained from version 2.1.6 of the Integrated Planning Model (IPM) (*http://www.epa.gov/airmarkets/epa-ipm/index.html*). However, results from this version of the IPM model were not available at the time that the air quality model runs to determine interstate contributions ("zero-out runs") were started. Therefore, we used EGU emissions from the previous IPM version (v2.1) for the zero-out air quality model runs and associated 2010 Base Case. Updates applied to the IPM model between versions 2.1 and 2.1.6 include the update of coal and natural gas supply curves and the incorporation of several State-mandated emission caps and New Source Review (NSR) settlements.

Tables IV–1 and IV–2 provide State-level emissions totals for the 2010 Base Case for SO and NO_X, respectively, for each of the five sectors. These tables are helpful in understanding the relative magnitude of each sector to the total inventory. In addition, these tables include, for comparison, a column showing the EGU emissions from the older version 2.1 IPM outputs that were used for the zero-out modeling analysis. Our examination indicates that the EGU differences between the two IPM outputs are generally minor and have not affected the content of this proposal.

TABLE IV–1.—STATE SO_2 EMISSIONS BY SECTOR IN THE 2010 BASE CASE[1]

ST	EGU v21	EGU v216	Non-EGU	On-road	Non-road	Area	Total
AL	494,700	473,000	121,300	600	1,600	51,900	648,400
AZ	47,800	47,800	120,800	600	700	4,300	174,200
AR	119,300	122,700	17,500	300	500	21,200	162,100
CA	17,300	17,300	44,000	3,400	13,000	10,700	88,400
CO	90,400	73,100	15,900	500	800	4,700	94,900
CT	6,600	6,300	7,600	300	400	500	15,000
DE	36,800	46,400	38,400	100	300	10,200	95,400
DC	0	0	2,100	0	100	5,800	8,000
FL	230,300	233,200	90,400	1,700	15,100	44,700	385,300
GA	610,000	609,200	92,800	1,100	2,600	6,700	712,300
ID	0	0	26,800	200	300	8,800	36,000
IL	591,500	600,800	277,200	1,100	1,700	36,400	917,300
IN	599,000	670,400	152,200	800	1,100	2,200	826,700
IA	186,200	169,900	84,000	300	600	14,600	269,400

[56] The 2001 NEI emissions for EGUs includes emissions for units reporting to EPA under title IV.

TABLE IV–1.—STATE SO_2 EMISSIONS BY SECTOR IN THE 2010 BASE CASE [1]—Continued

ST	EGU v21	EGU v216	Non-EGU	On-road	Non-road	Area	Total
KS	71,500	63,500	16,000	300	800	3,500	84,100
KY	393,300	363,100	42,900	500	1,800	58,000	466,400
LA	96,300	112,500	193,600	400	21,100	94,000	421,700
ME	4,700	3,200	22,200	200	200	10,800	36,600
MD	261,400	232,200	22,500	600	8,100	900	264,300
MA	17,700	15,600	15,300	600	1,200	61,300	94,000
MI	375,800	387,600	135,000	1,000	1,300	32,700	557,600
MN	94,200	91,600	41,200	500	1,100	5,700	140,000
MS	84,600	73,500	77,500	400	2,000	82,700	236,100
MO	261,000	293,100	128,600	700	900	31,900	455,200
MT	17,700	17,900	34,700	100	300	1,400	54,400
NE	97,200	97,600	7,300	200	600	10,100	115,800
NV	56,700	16,400	3,500	200	400	3,900	24,300
NH	7,300	7,300	7,900	100	200	90,800	106,300
NJ	85,300	41,300	70,800	700	53,500	42,600	208,900
NM	48,300	48,600	115,200	300	200	9,400	173,700
NY	211,400	214,100	168,600	1,300	2,200	122,100	508,200
NC	221,500	219,400	95,400	1,000	1,200	33,800	350,800
ND	172,200	160,900	56,100	100	400	64,100	281,600
OH	979,300	1,258,700	337,600	1,200	5,700	63,300	1,666,40
OK	133,000	133,000	41,200	500	600	5,500	180,800
OR	15,200	15,200	6,600	400	800	20,900	43,800
PA	670,200	853,400	141,000	1,100	3,300	80,900	1,079,80
RI	0	0	2,400	100	2,900	4,100	9,500
SC	191,500	199,700	63,900	500	1,200	15,600	280,900
SD	42,100	36,300	1,400	100	200	23,800	61,800
TN	317,300	306,100	134,300	700	2,800	47,800	491,700
TX	539,900	487,700	318,600	2,300	33,400	9,600	851,700
UT	31,200	31,500	30,300	300	400	13,100	75,600
VT	0	0	2,000	100	100	13,000	15,100
VA	180,600	187,800	112,700	900	4,600	9,500	315,400
WA	6,000	6,000	51,600	600	9,500	3,700	71,400
WV	456,800	550,600	62,200	200	33,600	11,300	658,000
WI	217,200	214,100	88,500	600	800	45,900	349,800
WY	47,100	47,300	59,700	100	200	17,300	124,600
	9,435,400	9,856,900	3,799,200	29,800	236,400	1,367,600	15,290,0

[1] All values rounded to nearest 100 tons. EGU v216 emissions are latest version and are included in totals. EGU v21 emissions were used for the zero-out analysis.

TABLE IV–2.—STATE NO_X EMISSIONS BY SECTOR IN THE 2010 BASE CASE [1]

ST	EGU v21	EGU v216	Non-EGU	On-road	Non-road	Area	Total
AL	129,500	134,100	83,400	110,200	55,800	69,400	453,000
AZ	88,200	84,600	118,200	91,300	43,600	78,100	415,700
AR	52,600	52,500	23,500	64,900	35,400	44,800	221,100
CA	18,200	17,700	137,300	401,900	276,100	129,300	962,300
CO	87,000	82,700	44,900	80,600	57,000	59,900	325,100
CT	6,700	5,200	11,300	48,500	17,300	9,300	91,600
DE	11,500	10,300	8,500	17,400	16,800	6,900	59,900
DC	100	0	800	4,800	5,400	1,900	13,000
FL	162,900	161,800	59,000	293,900	147,900	53,200	716,000
GA	152,500	150,600	71,400	189,200	66,400	74,700	552,300
ID	1,400	1,200	6,600	32,700	17,300	29,400	87,200
IL	194,200	171,400	134,900	177,700	150,200	115,800	750,100
IN	223,300	239,700	45,400	142,900	90,400	37,900	556,300
IA	95,400	86,100	26,500	61,600	57,600	31,100	262,900
KS	101,400	100,900	108,800	59,100	79,500	74,300	422,600
KY	186,300	195,900	34,800	95,700	73,100	76,900	476,400
LA	64,700	49,800	297,100	89,300	205,000	103,500	744,700
ME	6,000	2,100	15,600	30,600	8,800	4,900	62,000
MD	60,500	60,600	19,100	73,100	38,900	15,900	207,700
MA	27,800	10,400	18,200	74,400	70,000	24,900	197,800
MI	126,200	125,400	161,000	171,400	63,200	115,600	636,500
MN	109,700	104,500	83,800	103,400	64,800	24,800	381,500
MS	49,700	43,200	74,400	68,800	44,800	56,700	287,800
MO	144,700	137,000	29,700	117,800	64,200	14,800	363,600
MT	38,500	38,500	20,800	24,800	34,000	18,400	136,400
NE	58,100	57,800	14,500	37,700	57,400	15,400	182,800
NV	44,800	37,400	6,000	36,300	25,400	8,500	113,500

TABLE IV–2.—STATE NO_X EMISSIONS BY SECTOR IN THE 2010 BASE CASE [1]—Continued

ST	EGU v21	EGU v216	Non-EGU	On-road	Non-road	Area	Total
NH	3,000	3,600	4,200	25,700	6,200	13,900	53,700
NJ	40,000	29,300	51,000	93,100	86,400	79,800	339,600
NM	77,300	76,400	68,700	54,500	10,700	32,400	242,800
NY	58,700	68,400	36,700	181,500	90,900	88,100	465,600
NC	64,700	62,100	63,300	150,000	60,100	37,000	372,400
ND	81,100	77,900	7,200	16,400	41,800	21,200	164,600
OH	249,100	266,800	77,500	201,300	116,900	82,200	744,700
OK	97,700	82,100	121,000	86,800	40,000	33,200	363,100
OR	18,000	13,300	16,800	67,400	52,600	39,900	190,000
PA	212,100	209,800	173,000	200,600	80,600	114,300	778,300
RI	1,300	1,400	900	12,300	5,600	2,800	23,000
SC	67,500	64,700	46,000	94,200	29,900	26,100	260,900
SD	13,800	11,700	4,700	20,200	24,400	7,900	69,000
TN	106,700	102,800	78,000	132,900	138,900	52,300	505,000
TX	246,200	200,900	523,800	399,600	432,100	43,100	1,599,50
UT	68,400	69,400	31,600	49,000	31,500	23,500	205,100
VT	0	0	800	16,000	3,900	11,500	32,100
VA	55,800	55,500	66,500	147,000	76,600	45,700	391,300
WA	26,600	28,400	47,000	114,600	78,800	23,000	291,800
WV	142,500	155,200	50,100	40,400	57,000	21,300	324,000
WI	116,200	111,500	54,300	109,600	51,000	58,700	385,100
WY	90,300	90,500	49,500	18,600	22,900	71,700	253,200
	4,079,200	3,943,400	3,228,200	4,931,900	3,405,000	2,225,900	17,734,4

[1] All values rounded to nearest 100 tons. EGU v216 emissions are latest version and are included in totals. EGU v21 emissions were used for the zero-out analysis.

b. Development of Emissions Inventories for On-road Vehicles

The 2001 base year inventory for the on-Road vehicle sector was developed by applying State and pollutant specific adjustment ratios to each grid cell's emissions as found in the existing 1996 model-ready file for on-road sources. The adjustment ratios were created by dividing State-level emissions for each pollutant as estimated for the 2001 NEI using the MOBILE6 model by the State-level emissions for 1996 as estimated using the same MOBILE6 model.

The 1996 model-ready file, along with consistent files for 2007 and 2020 emissions, had been developed for previous EPA rulemakings using a version of the MOBILE5b model which had been adjusted to simulate the MOBILE6 model that was under development at that time. The 1996 and 2007 emissions files had been developed for the HDDE rule (*http://www.epa.gov/otaq/models/hd2007/r00020.pdf*) and the 2020 emissions file had been developed for the LNDE rule (*http://www.epa.gov/nonroad/454r03009.pdf*). Note that the 2020 on-road vehicle emissions file developed for the LNDE rule includes the reductions expected from implementation of the HDDE rule.

Application of the MOBILE6-based adjustment ratios to the 1996 MOBILE5b-based emission file allowed the resulting 2001 model-ready file to remain consistent in methodology with the existing 2007 and 2020 files. The 2010 and 2015 base case emissions files used for this proposal were then developed as straight-line interpolations between those 2007 and 2020 files, and they are therefore also consistent with the 2001 file.

c. Development of Emissions Inventories for Non-Road Engines

For the non-road sector, the 2001 model-ready emissions file was developed in a manner similar to that described above for the on-road vehicle sector. State-level 2001 NEI emissions developed from the NONROAD2002 model were divided by a consistent set of emissions for 1996, also developed using the NONROAD2002 model, to produce a set of adjustment ratios for each State and pollutant. These adjustment ratios were applied to the existing 1996 model-ready emissions for each grid cell to produce a 2001 model-ready file that remains consistent with the 1996 file and the existing future projections that were based on that 1996 file.

For the future scenarios, the 2010 and 2020 emissions files developed for EPA's analysis of the preliminary controls of the LNDE rule were modified to reflect that rule as finally proposed (68 FR 28327, May 23, 2003) and to incorporate the effects of the Large Spark Ignition and Recreational Vehicle rules. These modifications were done using adjustment ratios developed from national-level estimates of the benefits of these two rules. A 2015 emissions file for this sector was then developed as a straight-line interpolation between the modified 2010 and 2020 files.

d. Development of Emissions Inventories for Other Sectors

The NEI estimates for 2001 were not available at the time modeling was begun for the remaining two man-made emission sectors: non-EGU point sources and area sources. For these two sectors, linear interpolations were performed between gridded 1996 emissions and gridded projected 2010 base case emissions to produce gridded 2001 emissions files. The gridded emissions input files for 1996 and 2010 were available from previous EPA analyses. The interpolations were done separately for each of the two sectors, for each grid cell, and for each pollutant. The 2010 and 2015 emissions files for these sectors that were used as part of this interpolation to 2001 were themselves developed as straight-line interpolations between the 2007 and 2020 inventories described above for the on-road vehicle sector. The interpolated 2010 and 2015 emissions were adjusted to reflect the SO_2, PM_{10}, and $PM_{2.5}$ co-control benefits of the proposed Industrial Boiler and Process Heater MACT (68 FR 1660, January 13, 2003). The 2007 and 2020 projection inventories had been developed by applying State- and 2-digit SIC-specific economic growth ratios to the 1996 NEI, followed by application of any emissions control regulations.

5. Preparation of Emissions for Air Quality Modeling

The annual and summer day emissions inventory files were processed through the Sparse Matrix Operator Kernel Emissions (SMOKE) Modeling System version 1.4 to produce 36–km gridded input files for annual $PM_{2.5}$ air quality modeling and 12–km input files for episodic ozone air quality modeling. In addition to the U.S. man-made emission sources described above, hourly biogenic emissions were estimated for individual modeling days using the BEIS model version 3.09 (*ftp.epa.gov/amd/asmd/beis3v09/*). Emissions inventories for Canada and for U.S. offshore oil platforms were merged in using SMOKE to provide a more complete modeling data set. The single set of biogenic, Canadian, and offshore U.S. emissions was used in all scenarios modeled. That is, the emissions for these sources were not varied from run to run. Additional information on the development of the emissions data sets for modeling is provided in the AQMTSD.

D. Ozone Air Quality Modeling

1. Ozone Modeling Platform

The CAM_X was used to assess 8-hour ozone concentrations as part of this rulemaking. The CAM_X is a publicly available Eulerian model that accounts for the processes that are involved in the production, transport, and destruction of ozone over a specified three-dimensional domain and time period. Version 3.10 of the CAM_X model was employed for this analyses. More information on the CAM_X model can be found in the model user's guide.[57] The model simulations were performed for a domain covering the Eastern U.S. and adjacent portions of Canada.

Three episodes during the summer of 1995 were used for modeling ozone and precursor pollutants: June 12–24, July 5–15, and August 10–21. The start of each episode was chosen to correspond to a day with no ozone exceedances (an exceedance is an 8-hour daily maximum ozone concentration of 85 ppb or more). The first three days of each episode are considered ramp-up days and were discarded from analysis to minimize effects of the clean initial concentrations used at the start of each episode. In total, thirty episode days were used for analyzing interstate transport. As described in the AQMTSD, these episodes contain meteorological conditions that reflect various ozone transport wind patterns across the East. In general, ambient ozone concentrations during these episodes span the range of 2000–2002 8-hour ozone design values at monitoring sites in the East.

In order to solve for the change in pollutant concentrations over time and space, the CAM_X model requires certain meteorological inputs for the episodes being modeled, including: winds, temperature, water vapor mixing ratio, atmospheric air pressure, cloud cover, rainfall, and vertical diffusion coefficient. Most of the gridded meteorological data for the three historical 1995 episodes were developed by the New York Department of Environment and Conservation using the Regional Atmospheric Modeling System (RAMS), version 3b. A model performance evaluation [58] was completed for a portion of the 1995 meteorological modeling (July 12–15). Observed data not used in the assimilation procedure were compared against modeled data at the surface and aloft. This evaluation concluded there were no widespread biases in the RAMS meteorological data. The remaining meteorological inputs (cloud fractions and rainfall rates) were developed based on observed data.

2. Ozone Model Performance Evaluation

The CAM_X model was run with Base Year emissions in order to evaluate the performance of the modeling platform for replicating observed concentrations. This evaluation was comprised principally of statistical assessments of paired model/observed data. The results indicate that, on average, the predicted patterns and day-to-day variations in regional ozone levels are similar to what was observed with measured data. When all hourly observed ozone values (greater than 60 ppb) are compared to their model counterparts for the 30 days modeled (paired in time and space), the mean normalized bias is -1.1 percent and the mean normalized gross error is 20.5 percent. As described in the AQMTSD, the performance for individual episodes indicates variations in the degree of model performance with a tendency for underprediction during the June and July episodes and overprediction during the August episode.

At present, there are no generally accepted statistical criteria by which one can judge the adequacy of model performance for regional scale ozone model applications. However, as documented in the AQMTSD, the base year modeling for today's rule represents an improvement in terms of statistical model performance when compared to prior regional modeling analyses (*e.g.*, model performance analyses for OTAG, the Tier-2/Low Sulfur Rule, and the Heavy Duty Engine Rule).

3. Projection of Future 8-Hour Ozone Nonattainment

Ozone modeling was performed for 2001 emissions and for the 2010 and 2015 Base Cases as part of the approach for forecasting which counties are expected to be nonattainment in these 2 future years. In general, the approach involves using the model in a relative sense to estimate the change in ozone between 2001 and each future base case. Concentrations of ozone in 2010 were estimated by applying the relative change in model predicted ozone from 2001 to 2010 with present-day 8-hour ozone design values (2000–2002). The procedures for calculating future case ozone design values are consistent with EPA's draft modeling guidance [59] for 8-hour ozone attainment demonstrations, "Draft Guidance on the Use of Models and Other Analyses in Attainment Demonstrations for the 8-Hour Ozone NAAQS." The draft guidance specifies the use of the higher of the design values from (a) the period that straddles the emissions inventory Base Year or (b) the design value period which was used to designate the area under the ozone NAAQS. In this case, 2000–2002 is the design value period which straddles the 2001 Base Year inventory and is also the latest period which is available for determining designation compliance with the NAAQS. Therefore, 2000–2002 was the only period used as the basis for projections to the future years of 2010 and 2015.

The procedures in the guidance for projecting future 8-hour ozone nonattainment are as follows:

Step 1: Hourly model predictions are processed to determine daily maximum 8-hour concentrations for each episode day modeled. A relative reduction factor (RRF) is then determined for each monitoring site. First, the multi-day mean (excluding ramp-up days) of the 8-hour daily maximum predictions in the nine grid cells that include or surround the site is calculated using only those

[57] Environ, 2002: User's Guide to the Comprehensive Air Quality Model with Extensions (CAM_X), Novato, CA.

[58] Hogrefe, C., S.T. Rao, P. Kasibhatla, G. Kallos, C. Tremback, W. Hao, D. Olerud, A. Xiu, J. McHenry, K. Alapaty, 2001. "Evaluating the performance of regional-scale photochemical modeling systems: Part-I meteorological predictions." *Atmospheric Environment*, vol. 35, No. 34, 4159–4174.

[59] U.S. EPA, 1999: *Draft Guidance on the Use of Models and Other Analyses in Attainment Demonstrations for the 8-Hour Ozone NAAQS*, Office of Air Quality Planning and Standards, Research Triangle Park, NC.

predictions greater than or equal to 70 ppb, as recommended in the guidance. This calculation is performed for the base year 2001 scenario and the future-year scenario. The RRF for a site is the ratio of the mean prediction in the future-year scenario (*e.g.*, 2010) to the mean prediction in the 2001 base year scenario. The RRFs were calculated on a site-by-site basis.

Step 2: The RRF for each site is then multiplied by the 2000–2002 ambient design value for that site, yielding an estimate of the future design value at that particular monitoring location.

Step 3: For counties with only one monitoring site, the value at that site was selected as the value for that county. For counties with more than one monitor, the highest value in the county was selected as the value for that county. Counties with projected 8-hour ozone design values of 85 ppb or more are projected to be nonattainment.

As an example, consider Clay County, Alabama which has one ozone monitor. The 2000–2002 8-hour ambient ozone design value is 82 ppb. In the 2001 base year simulation, 24 of the 30 episode modeling days have CAMx values of 70 ppb or more in one of the nine grid cells that include or surround the monitor location. The average of these predicted ozone values is 88.62 ppb. In 2010, the average of the predicted values for these same grid cells was 70.32 ppb. Therefore, the RRF for this location is 0.79, and the projected 2010 design value is 82 multiplied by 0.79 equals 65.07 ppb. All projected future case design values are truncated to the nearest ppb (*e.g.*, 65.07 becomes 65). Since there are no other monitoring locations in Clay County, Alabama, the projected 2010 8-hour design value for this county is 65 ppb.

The RRF approach described above was applied for the 2010 and 2015 Base Case scenarios. The resulting 2010 and 2015 Base Case design values are provided in the AQMTSD. Of the 287 counties that were nonattainment based on 2000–2002 design values, 47 are forecast to be nonattainment in 2010 and 34 in 2015. None of the counties that were measuring attainment in the period 2000–2002 are forecast to become nonattainment in the future. Those counties projected to be nonattainment for the 2010 and 2015 Base Cases are listed in Table IV–3.

TABLE IV–3.—COUNTIES PROJECTED TO BE NONATTAINMENT FOR THE 8-HOUR OZONE NAAQS IN THE 2010 AND 2015 BASE CASES

State	2010 Base case projected nonattainment counties	2015 Base case porojected nonattainment counties
AR	Crittenden	Crittenden.
CT	Fairfield, Middlesex, New Haven	Fairfield, Middlesex, New Haven.
DC	Washington, DC	Washington, DC.
DE	New Castle	None.
GA	Fulton	None.
IL	None	Cook.
IN	Lake	Lake.
MD	Anne Arundel, Baltimore, Cecil, Harford, Kent, Prince Georges.	Anne Arundel, Cecil, Harford.
MI	None	Macomb.
NJ	Bergen, Camden, Cumberland, Gloucester, Hudson, Hunterdon, Mercer, Middlesex, Monmouth, Morris, Ocean.	Bergen, Camden, Gloucester, Hunterdon, Mercer, Middlesex, Monmouth, Morris, Ocean.
NY	Erie, Putnam, Richmond, Suffolk, Westchester	Erie, Richmond, Suffolk, Westchester.
NC	Mecklenburg	None.
OH	Geauga, Summit	Geauga.
PA	Allegheny, Bucks, Delaware, Montgomery, Philadelphia	Bucks, Montgomery, Philadelphia.
RI	Kent	Kent.
TX	Denton, Harris, Tarrant	Harris.
VA	Arlington, Fairfax	Arlington, Fairfax.
WI	Kenosha, Racine, Sheboygan	Kenosha, Sheboygan.

The counties projected to be nonattainment for the 2010 Base Case are the nonattainment receptors used for assessing the contribution of emissions in upwind States to downwind nonattainment as part of today's proposal. It should be noted that the approach used to identify these nonattainment receptors differed from that used in the NO_X SIP Call where we aggregated on a State-by-State basis all grid cells which were both (a) associated with counties that violated the 8-hour NAAQS (based on 1994–1996 data), and (b) had future base case predictions of 85 ppb or more. For this proposal, we have treated each individual county projected to be nonattainment in the future as a downwind nonattainment receptor.

E. The $PM_{2.5}$ Air Quality Modeling

1. The $PM_{2.5}$ Modeling Platform

The REMSAD model version 7 was used as the tool for simulating base year and future concentrations of $PM_{2.5}$ in support of today's proposed rule. The REMSAD is a publicly available model. An overview of the scientific aspects of this model is provided below. More detailed information can be found in the REMSAD User's Guide.[60] The basis for REMSAD is the atmospheric diffusion equation (also called the species continuity or advection/diffusion equation). This equation represents a mass balance in which all of the relevant emissions, transport, diffusion, chemical reactions, and removal processes are expressed in mathematical terms.

The REMSAD simulates both gas phase and aerosol chemistry. The gas phase chemistry uses a reduced-form version of Carbon Bond (CB4) chemical mechanism termed "micro-CB4" (mCB4). Formation of secondary PM species, such as sulfate[61] and nitrate, is simulated through chemical reactions within the model. Aerosol sulfate is formed in both the gas phase and the aqueous phase. The REMSAD also accounts for the production of secondary organic aerosols through atmospheric chemistry processes. Direct PM emissions in REMSAD are treated as inert species which are advected and

[60] ICF Kaiser, 2002: *User's Guide to the Regional Modeling System for Aerosols and Deposition (REMSAD) Version 7*, San Rafael, CA.

[61] Ammonium sulfates are referred to as "sulfate" in sections IV and V of today's proposed rule.

deposited without any chemical interaction with other species.

The REMSAD was run using a latitude/longitude horizontal grid structure in which the horizontal grids are generally divided into areas of equal latitude and longitude. The grid cell size was approximately 36 km by 36 km. The REMSAD was run with 12 vertical layers extending up to 16,000 meters, with a first layer thickness of approximately 38 meters. The REMSAD modeling domain used for this analysis covers the entire continental United States.

The REMSAD requires input of winds, temperatures, surface pressure, specific humidity, vertical diffusion coefficients, and rainfall rates. The meteorological input files were developed from a 1996 annual MM5 model run that was developed for previous projects. The MM5 is a numerical meteorological model that solves the full set of physical and thermodynamic equations which govern atmospheric motions. The MM5 was run in a nested-grid mode with 2 levels of resolution: 108 km, and 36km with 23 vertical layers extending from the surface to the 100 mb pressure level.[62] All of the $PM_{2.5}$ model simulations were performed for a full year using the 1996 meteorological inputs.

2. The $PM_{2.5}$ Model Performance Evaluation

An annual simulation of REMSAD was performed for 1996 using the meteorological data and emissions data for that year. The predictions from the 1996 Base Year modeling were used to evaluate model performance for predicting concentrations of $PM_{2.5}$ and its related speciated components (*e.g.*, sulfate, nitrate, elemental carbon, organic carbon). The evaluation was comprised principally of statistical assessments of model versus observed pairs.

The evaluation used data from the IMPROVE,[63] CASTNet[64] dry deposition, and NADP[65] monitoring networks. The IMPROVE and NADP networks were in full operation during 1996. The CASTNet dry deposition network was partially shutdown during the first half of the year. There were 65 CASTNet sites with at least one season of complete data. There were 16 sites which had complete annual data. The largest available ambient data base for 1996 comes from the IMPROVE network. The IMPROVE network is a cooperative visibility monitoring effort between EPA, Federal land management agencies, and State air agencies. Data is collected at Class I areas across the United States mostly at national parks, national wilderness areas, and other protected pristine areas. There were approximately 60 IMPROVE sites that had complete annual $PM_{2.5}$ mass and/or $PM_{2.5}$ species data for 1996. Forty-two sites were in the West[66] and 18 sites were in the East. The following is a brief summary of the model performance for $PM_{2.5}$ and deposition. Additional details on model performance are provided in the AQMTSD.

Considering the ratio of the annual mean predictions to the annual mean observations (*e.g.*, predicted divided by observed) at the IMPROVE monitoring sites REMSAD underpredicted fine particulate mass ($PM_{2.5}$), by 18 percent. Specifically, $PM_{2.5}$ in the East was underpredicted by 2 percent, while $PM_{2.5}$ in the West was underpredicted by 33 percent. Sulfate in the East is slightly underpredicted and nitrate and largely crustal material are overestimated. Elemental carbon is neither overpredicted nor underpredicted in the East. Organic aerosols are slightly overpredicted in the East. All $PM_{2.5}$ component species were underpredicted in the West.

The comparisons to the CASTNet data show generally good model performance for sulfate. Comparison of total nitrate indicate an overestimate, possibly due to overpredictions of nitric acid in the model.

Performance at the NADP sites for wet deposition of ammonium, sulfate, and nitrate was reasonably good. However, the nitrate and sulfate wet deposition were each underestimated compared to the corresponding observed values.

Given the state of the science relative to PM modeling, it is inappropriate to judge PM model performance using criteria derived for other pollutants, like ozone. The overall model performance results may be limited by our current knowledge of PM science and chemistry, by the emissions inventories for direct PM and secondary PM precursor pollutants, by the relatively sparse ambient data available for comparisons to model output, and by uncertainties in monitoring techniques. The model performance for sulfate in the East is quite reasonable, which is key since sulfate compounds comprise a large portion of $PM_{2.5}$ in the East.

Negative effects of relatively poor model performance for some of the smaller (*i.e.*, lower concentration) components of $PM_{2.5}$, such as crustal mass, are mitigated to some extent by the way we use the modeling results in projecting future year nonattainment and downwind contributions. As described in more detail below, each measured component of $PM_{2.5}$ is adjusted upward or downward based on the percent change in that component, as determined by the ratio of future year to base year model predictions. Thus, we are using the model predictions in a relative way, rather than relying on the absolute model predictions for the future year scenarios. By using the modeling in this way, we are reducing the risk that large overprediction or underprediction will unduly affect our projection of future year concentrations. For example, REMSAD may overpredict the crustal component at a particular location by a factor of 2, but since measured crustal concentrations are generally a small fraction of ambient $PM_{2.5}$, the future crustal concentration will remain as a small fraction of $PM_{2.5}$.

A number of factors need to be considered when interpreting the results of this performance analysis. First, simulating the formation and fate of particles, especially secondary organic aerosols and nitrates is part of an evolving science. In this regard, the science in air quality models is continually being reviewed and updated as new research results become available. Also, there are a number of issues associated with the emissions and meteorological inputs, as well as ambient air quality measurements and how these should be paired to model predictions that are currently under investigation by EPA and others. The process of building consensus within the scientific community on ways for doing PM model performance evaluations has not yet progressed to the point of having a defined set of common approaches or criteria for judging model performance. Unlike ozone, there is a limited data base of past performance statistics against which to measure the performance of regional/national PM modeling. Thus, the approach used for this analysis may be modified or expanded in future evaluation analyses.

[62] Olerud, D., K. Alapaty, and N. Wheeler, 2000: *Meteorological Modeling of 1996 for the United States with MM5*. MCNC-Environmental Programs, Research Triangle Park, NC.

[63] IMPROVE, 2000. *Spatial and Seasonal Patterns and Temporal Variability of Haze and its Constituents in the United States: Report III*. Cooperative Institute for Research in the Atmosphere, ISSN: 0737–5352–47.

[64] U.S. EPA, *Clean Air Status and Trends Network (CASTNet), 2001 Annual Report*.

[65] NADP, 2002: *National Acid Deposition Program 2002 Annual Summary*.

[66] The dividing line between the West and East was defined as the 100th meridian (*e.g.*, monitoring sites to the east of this meridian are included in aggregate performance statistics for the East).

3. Projection of Future $PM_{2.5}$ Nonattainment

As with ozone, the approach for identifying areas expected to be nonattainment for $PM_{2.5}$ in the future involves using the model predictions in a relative way to forecast current $PM_{2.5}$ design values to 2010 and 2015. The modeling portion of this approach includes annual simulations for 2001 emissions and for the 2010 and 2015 Base Case emissions scenarios. As described below, the predictions from these runs were used to calculate RRFs which were then applied to current $PM_{2.5}$ design values. The approach we followed is consistent with the procedures in the draft $PM_{2.5}$ air quality modeling guidance,[67] "Guidance for Demonstrating Attainment of Air Quality Goals for $PM_{2.5}$ and Regional Haze." It should be noted that the approach for $PM_{2.5}$ differs from the approach recommended for projecting future year 8-hour ozone design values in terms of the base period for design values. The approach for ozone uses the higher of the ambient design values for two 3-year periods, as described above. In contrast, the $PM_{2.5}$ guidance recommends selecting the highest design value from among the three periods that straddle the base emissions year (*i.e.*, 2001). The three periods that straddle this year are 1999–2001, 2000–2002, and 2001–2003. The data from the first two design value periods are readily available, but the data from the 2001–2003 period could not be used since the 2003 data were not yet available. Thus, we have relied on the data for the two periods 1999–2001 and 2000–2002. The design values from the period 2000–2002, which is the most recent period with available data, were used to identify which monitors are currently measuring nonattainment (*i.e.*, annual average $PM_{2.5}$ of 15.05 μg/m^3 or more). To be consistent with procedures in the modeling guideline, we selected the higher of the 1999–2001 or 2000–2002 design value from each nonattainment monitor for use in projecting future design values. The recommendation in the guidance for selecting the highest values from among 3 periods is applicable for nonattainment counties, but not necessarily for attainment counties. Thus, for monitors that are measuring attainment (*i.e.*, $PM_{2.5}$ less than 15.05 μg/m^3) using the most recent 3 years of data, we used the 2000–2002 design values as the starting point for projecting future year design values. Note that none of the counties that are attainment for the period 2000–2002 are forecast to become nonattainment in 2010 or 2015.

The modeling guidance recommends that model predictions be used in a relative sense to estimate changes expected to occur in each major $PM_{2.5}$ species. These species are sulfate, nitrate, organic carbon, elemental carbon, crustal and un-attributed mass. Un-attributed mass is defined as the difference between FRM $PM_{2.5}$ and the sum of the other five components. The procedure for calculating future year $PM_{2.5}$ design values is called the Speciated Modeled Attainment Test (SMAT). The following is a brief summary of those steps. Additional details are provided in the AQMTSD.

Step 1: Calculate quarterly mean concentrations (averaged over 3 years) for each of the six major components of $PM_{2.5}$. This is done by multiplying the monitored quarterly mean concentration of FRM-derived $PM_{2.5}$ by the monitored fractional composition of $PM_{2.5}$ species for each quarter in 3 consecutive years (*e.g.*, 20 percent sulfate multiplied by 15 μg/m^3 $PM_{2.5}$ equals 3 μg/m^3 sulfate).

Step 2: For each quarter, calculate the ratio of future (*e.g.*, 2010) to current (*i.e.*, 2001) predictions for each component specie. The result is a component-specific RRF (*e.g.*, assume that 2001 predicted sulfate for a particular location is 10 μg/m^3 and the 2010 Base concentration is 8 μg/m^3, then RRF for sulfate is 0.8).

Step 3: For each quarter and each component specie, multiply the current quarterly mean component concentration (Step 1) by the component-specific RRF obtained in Step 2. This produces an estimated future quarterly mean concentration for each component (*e.g.*, 3 μg/m^3 sulfate multiplied by 0.8 equals future sulfate of 2.4 μg/m^3).

Step 4: Average the four quarterly mean future concentrations to get an estimated future annual mean concentration for each component specie. Sum the annual mean concentrations of the 6 components to obtain an estimated future annual average concentration for $PM_{2.5}$.

We are using the FRM data for projecting future design values since these data will be used for nonattainment designations. In order to apply SMAT to the FRM data, information on $PM_{2.5}$ speciation is needed for the location of each FRM monitoring site. Only a small number of the FRM sites have measured species information. Therefore, spatial interpolation techniques were applied to the speciated component averages from the IMPROVE and Speciation Trends Network (STN) data to estimate concentrations of species mass at all FRM $PM_{2.5}$ monitoring sites. Details on the procedures and assumptions used in mapping the IMPROVE and STN data to the locations of the FRM sites are described in the AQMTSD.

The preceding procedures for determining future year $PM_{2.5}$ concentrations were applied for each FRM site. For counties with only one FRM site, the forecast design value for that site was used to determine whether or not the county will be nonattainment in the future. For counties with multiple monitoring sites, the site with the highest future concentration was selected for that county. Those counties with future year design values of 15.05 μg/m^3 or more are predicted to be nonattainment. The result is that 61 counties in the East are forecast to be nonattainment for the 2010 Base Case. Of these, 41 are forecast to remain nonattainment for the 2015 Base Case. The $PM_{2.5}$ nonattainment counties for the 2010 and 2015 Base Cases are listed in Table IV–4. These counties were used as receptors for quantifying the impacts of the SO_2 and NO_X emissions reductions in today's proposal, as presented in section IX.

TABLE IV–4. COUNTIES PROJECTED TO BE NONATTAINMENT FOR THE ANNUAL AVERAGE $PM_{2.5}$ NAAQS FOR THE 2010 AND 2015 BASE CASES

State	2010 Base case projected nonattainment counties	2015 Base case projected nonattainment counties
AL	DeKalb, Jefferson, Montgomery, Russell, Talladaga	Jefferson, Montgomery, Russell, Talladaga.
CT	New Haven	New Haven.
DC	Washington, DC	None.
DE	New Castle	None.

[67] U.S. EPA, 2000: *Draft Guidance for Demonstrating Attainment of Air Quality Goals for $PM_{2.5}$ and Regional Haze;* Draft 1.1, Office of Air Quality Planning and Standards, Research Triangle Park, NC.

TABLE IV–4. COUNTIES PROJECTED TO BE NONATTAINMENT FOR THE ANNUAL AVERAGE $PM_{2.5}$ NAAQS FOR THE 2010 AND 2015 BASE CASES—Continued

State	2010 Base case projected nonattainment counties	2015 Base case projected nonattainment counties
GA	Clarke, Clayton, Cobb, DeKalb, Floyd, Fulton, Hall, Muscogee, Paulding, Richmond, Wilkinson.	Clarke, Clayton, Cobb, DeKalb, Floyd, Fulton, Hall, Muscogee, Richmond, Wilkinson.
IL	Cook, Madison, St. Clair, Will	Cook, Madison, St. Clair.
IN	Clark, Marion	Clark, Marion.
KY	Fayette, Jefferson	Jefferson.
MD	Baltimore City	Baltimore City.
MI	Wayne	Wayne.
MO	St. Louis	None.
NY	New York (Manhattan)	New York (Manhattan).
NC	Catawba, Davidson, Mecklenburg	None.
OH	Butler, Cuyahoga, Franklin, Hamilton, Jefferson, Lawrence, Mahoning, Scioto, Stark, Summit, Trumbull.	Butler, Cuyahoga, Franklin, Hamilton, Jefferson, Scioto, Stark, Summit.
PA	Allegheny, Bucks, Lancaster, York	Allegheny, York.
SC	Greenville	None.
TN	Davidson, Hamilton, Knox, Roane, Sullivan	Hamilton, Knox.
WV	Brooke, Cabell, Hancock, Kanawha, Marshal, Wood	Brooke, Cabell, Hancock, Kanawha, Wood.

As noted above in section IV.C.4, the 2010 Base Case used for the zero-out $PM_{2.5}$ modeling included EGU emissions from an earlier simulation of the Integrated Planning Model. Of the 61 2010 Base Case nonattainment counties listed in Table IV–4, 4 counties (*i.e.*, Catawba Co., NC, Trumbull Co., OH, Greenville Co., SC, and Marshall Co., WV) were projected to be in attainment in the 2010 Base Case used for the zero-out modeling. Thus, 57 nonattainment counties (*i.e.*, the 61 counties in Table IV–4 less these 4 counties) were used as downwind receptors in the air quality modeling assessment of interstate $PM_{2.5}$ contributions described in section V.C.3.

F. Analysis of Locally-Applied Control Measures for Reducing $PM_{2.5}$

We conducted two air quality modeling analyses to assess the probability that attainment of the PM standard could be reached with local measures only. The results of these analyses, discussed in detail in the AQMTSD, support the need for today's rulemaking requiring reductions of transport pollutants. Both analysis were conducted by:

• Identifying a list of local control measures that could be applied in addition to those measures already in place or required to be in place in the near future;

• Determining the emissions inventory categories that would be affected by those measures, and the estimated percentage reduction;

• Applying those percentage reductions to sources within a selected geographic area; and

• Conducting regional large-scale air quality modeling using REMSAD to determine the ambient impacts those measures would have, and the degree to which those measures would reduce the expected number of nonattainment areas.

1. Control Measures and Percentage Reductions

For our analysis of $PM_{2.5}$ attainment prospects, we developed a list of emissions reductions measures as a surrogate for measures that State, local and Tribal air quality agencies might include in their $PM_{2.5}$ implementation plans. The list includes measures that such agencies might be able to implement to reach attainment in 2009 or as soon thereafter as possible. The measures address a broad range of man-made point, area, and mobile sources. In general, the measures represent what we consider to be a highly ambitious but achievable level of control.[68] We identified measures for direct $PM_{2.5}$ and also for the following $PM_{2.5}$ precursors: SO_2, NO_X, and VOC.[69] We did not attempt to address ammonia emissions, in part due to relatively low emissions of ammonia in urban areas and the likelihood of fewer controllable sources within the urban areas targeted for the analysis.

The percentage reductions were developed in two ways. First, we developed percentage reduction estimates for specific technologies when available. The available estimates were based on both the percentage control that might be achieved for sources applying that technology, and the percentage of the inventory the measures might be applicable to. For example, if a given technology would reduce a source's emissions by 90 percent where it was installed, but would be reasonable to install for only 30 percent of sources in the category, that technology would be assigned a percentage reduction of 90 times 30, or 27 percent.

Second, there were some groups of control measures where data and resources were not available to develop technology-specific estimates in this manner. For these, we felt it preferable to make broad judgments on the level of control that might be achieved rather than to leave these control measures out of the analysis entirely. For example, the analysis reflects a reduction of 3 percent from on-road mobile source emissions relative to a 2010 and 2015 baseline. We judged this 3 percent estimate to represent a reasonable upper bound on the degree to which transportation control measures and other measures for reducing mobile source emissions could reduce the overall inventory of mobile source emissions in a given area.

Additionally, we believe that it may be possible for point source owners to improve the performance of emissions control devices such as baghouses and electrostatic precipitators, and in some cases to upgrade to a more effective control device. In our current emissions inventories, we have incomplete data on control equipment currently in use. As a result, data are not available to calculate for each source the degree to which the control effectiveness could be improved. Nonetheless, we believed it important to include reasonable assumptions concerning controls for this category for direct $PM_{2.5}$. For this analysis, we assumed across the board that all point sources of PM could reduce emissions by 25 percent.

[68] Our assumptions regarding the measures for this analysis are not intended as a statement regarding the measures that represent RACT or RACM for $PM_{2.5}$ nonattainment areas.

[69] Some VOCs are precursors to the secondary organic aerosol component of $PM_{2.5}$.

Table IV–5 shows the control measures selected for the analysis, the pollutants reduced and the percentage reduction estimates.

2. Two Scenarios Analyzed for the Geographic Area Covered by Control Measures

We developed two scenarios for identifying the geographic area to which the control measures were applied. These two scenarios were intended to address two separate issues related to the effects of urban-based control measures.

The first scenario was intended to illustrate the effect of the selected local control measures within the geographic area to which controls were applied. For this, we applied the control measures and associated emissions reductions to the inventories for three cities—Birmingham, Chicago, and Philadelphia. We selected these three urban areas because each area was predicted to exceed the $PM_{2.5}$ standard in 2010, albeit to varying degrees. Additionally, the three urban areas were selected because they are widely separated. Accordingly, we were able to conduct a single air quality analysis with less concerns for overlapping impacts due to transport than if less separated cities were selected.

The control measures were applied to the projected 2010 baseline emission inventories for all counties within those Primary Metropolitan Statistical Areas (PMSAs).[70] Thus, for Chicago, measures were applied to the 10 counties in Illinois, but were not applied in northwest Indiana or Wisconsin. For Philadelphia, measures were applied to the New Jersey and Pennsylvania counties within the Philadelphia urban area. For Birmingham, measures were applied to four Alabama counties.

The second scenario was intended to address the cumulative impact of local control measures applied within nonattainment areas. Recognizing that $PM_{2.5}$ nonattainment areas may be near enough to each other to have transport effects between them, we applied the control measures identified in Table IV–5, with some modifications discussed below, to all 290 counties of the metropolitan areas we projected to contain any nonattainment county in 2010 in the baseline scenario. Specifically, the control measures were applied to all counties in Consolidated Metropolitan Statistical Areas (CMSAs) for which any county in the CMSA contained a nonattainment monitor.

3. Results of the Two Scenarios

Table IV–6 shows the results of applying the control measures in each of the three urban areas addressed in the first scenario. The emissions reductions were estimated to achieve ambient $PM_{2.5}$ reductions of about 0.5 $\mu g/m^3$ to about 0.9 $\mu g/m^3$, less than needed to bring any of the cities into attainment in 2010.

The SO_2 reductions in Birmingham were large—80 percent—because of the assumption that scrubbers would be installed for two large-emitting power plants within the Birmingham-area counties. Reductions of other pollutants in Birmingham, and of all pollutants in the two other cities, were 33 percent or lower. We note that despite the large reduction assumed for SO_2 emissions in the Birmingham area, ambient sulfate in Birmingham declined only 7 percent, indicating that the large majority of sulfate in Birmingham is attributable to SO_2 sources outside the metropolitan area.

TABLE IV–5.—CONTROL MEASURES, POLLUTANTS, AND PERCENTAGE REDUCTIONS FOR THE LOCAL MEASURES ANALYSIS

Source Description	Control Measure	SO_2	NO_X			$PM_{2.5}$			Tol+Xyl (VOC)		
		Eff	Eff	App	Red	Eff	App	Red	Eff	App	% Red
Utility boilers	FGD scrubber for some or all unscrubbed units.	(1)	....	....	....	....	....	....	....	....	....
Coal-fired industrial boilers > 250 mmBtu/hr.	Coal switching	50	....	....	....	....	....	....	....	....	....
Petroleum fluid catalytic cracking units.	Wet gas scrubber	50	....	....	....	....	....	....	....	....	....
Refinery process heaters—oil-fired.	Switch to natural gas	50	....	....	....	....	....	....	....	....	....
Sulfuric acid plants	Meet NSPS level	42–96	....	....	....	....	....	....	....	....	....
Coal-fired industrial boilers	SNCR	....	50	20	10	....	....	....	....	....	....
Gas-fired industrial boilers (large & medium).	SNCR	....	45	20	9	....	....	....	....	....	....
Gas-fired industrial boilers (small).	Low NO_X burner	....	50	20	10	....	....	....	....	....	....
Gas-fired IC Engines (reciprocating).	NSCR	....	94	10	9.4	....	....	....	....	....	....
Gas-fired turbine & cogeneration.	SCR	....	90	10	9	....	....	....	....	....	....
Asphalt Concrete, Lime Manufacture.	Low No_X burner	....	27	50	14	....	....	....	....	....	....
Cement Manufacturing	Tire derived fuel & mid-kiln firing.	....	34	50	18	....	....	....	....	....	....
Petroleum Refinery Gas-fired Process Heaters.	Ultra-low No_X burner & SNCR.	....	93	50	46.5	....	....	....	....	....	....
All direct $PM_{2.5}$ points sources.	Improve existing controls (baghouses, ESPs).	....	....	....	....	....	....	25	....	....	....
Wood fireplaces [2]	Natural gas inserts	....	....	....	....	80	30	24	....	....	....
	Replace with certified non-catalytic woodstove.	....	....	....	....	71	30	21.4	....	....	....

[70] For the three-city study, we chose the PMSA counties rather than the larger list of counties in the consolidated metropolitan statistical area (CMSA). Both the PMSA and the CMSA classifications for metrololitan areas are created by the Office of Management and Budget (OMB). For this study, we used the classifications of counties in place as of spring 2003, rather than the revised classifications released by OMB on June 6, 2003.

TABLE IV–5.—CONTROL MEASURES, POLLUTANTS, AND PERCENTAGE REDUCTIONS FOR THE LOCAL MEASURES ANALYSIS—Continued

Source Description	Control Measure	SO_2	NO_X			$PM_{2.5}$			Tol+Xyl (VOC)		
		Eff	Eff	App	Red	Eff	App	Red	Eff	App	% Red
HDDV including buses	Engine Modifications, Diesel oxidation catalyst.		40	5	2						
	Particulate filter					90	30	27			
	Idling reduction				1.7			1.7			1.7
Off-highway diesel construction and mining equipment.	Engine modifcations, diesel oxidation catalyst.		40	73	29						
	particulate filter					25	73	18			
Diesel Marine Vessels	SCR		75	5	4						
	Particulate filter					90	30	27			
Diesel locomotives	SCR		72	5	4						
	Electrification of yard	2.5	2.5	6	0.2	2.5	6	0.2	2.5	6	0.2
Unpaved roads	Gravel covering					60	30	18			
Construction road	Watering						50	30	15		
Open burning	Ban		100	75	75	100	75	75	100	75	75
Agricultural tilling	Soil conservation measures, unspecified.					20	30	6			
LDGV and LDGT1	Combination of unspecified measures to reduce highway vehicle miles and emissions.				3			3			3

[1] For the three-city study, we assumed controls to an emission rate of 0.15 lb/mmBtu on all currently unscrubbed coal-fired utility boilers within the three metropolitan areas. For the second scenario, we applied a 50 percent reduction to all unscrubbed utility units within the 290 counties, as a surrogate for a strategy that applied FGD scrubbers to enough units to achieve a 50 percent reduction overall.

[2] For the 1996 inventory, woodstoves and fireplaces are combined into one SCC category. We assumed for the purpose of this analysis, that woodstoves and fireplaces each comprise half of the total wood burned for the category overall. Thus, the total percentage reduction is (24+21.4)/2 = 22.7 percent.

TABLE IV–6.—MODELED $PM_{2.5}$ REDUCTIONS FROM APPLICATION OF HYPOTHETICAL LOCAL CONTROLS IN 3 URBAN AREAS

Metro area	2010 base $PM_{2.5}$ (µg/m³)	$PM_{2.5}$ reduction (µg/m³)	Final $PM_{2.5}$ (µg/m³)	Attainment achieved?
Birmingham, AL	20.07	−0.84	19.23	No.
Chicago, IL	18.01	−0.94	17.07	No.
Philadelphia, PA	15.6	−0.52	15.08	No.

Table IV–7 shows the results for the second scenario which, again, applied the same list of controls to 290 counties, resulting in local and transport reductions. These results show that some of the 2010 nonattainment areas would be projected to attain, but many are not. Accordingly, we concluded that for a sizable number of $PM_{2.5}$ nonattainment areas it will be difficult if not impossible to reach attainment unless transport is reduced to a much greater degree than by the simultaneous adoption of controls within only the nonattainment areas.

TABLE IV–7.—MODELED $PM_{2.5}$ REDUCTIONS FROM APPLICATION OF HYPOTHETICAL LOCAL CONTROLS IN ALL AREAS PREDICTED TO EXCEED THE NAAQS IN 2010

	Baseline	With local controls
Part A—Full Modeling Results Considering All Pollutants and Species		
Number of nonattainment counties	61	26
Average Reduction in $PM_{2.5}$ Design Value (µg/m³)	Not Applicable	1.26
Part B—Results Not Counting Reductions in Sulfate Component of $PM_{2.5}$		
Number of nonattainment counties	61	48
Average Reduction in $PM_{2.5}$ Design Value (µg/m₃)	Not Applicable	0.37

We were interested in what part of the $PM_{2.5}$ improvement seen in this modeling run was attributable to SO_2 reductions both locally and upwind. Part B of Table IV–7 shows a re-analysis of the modeling results in which the observed sulfate reductions were not considered in calculating the $PM_{2.5}$ effects of the control package. If, as we expect, the observation from the earlier described modeling of Birmingham and two other cities that local SO_2 reductions have relatively small local effects on sulfate applies more generally, then the difference between parts A and B of Table IV–7 would generally represent the effect of upwind reductions in SO_2 from power plants and other sources in other urban areas.

The results of the two scenarios show that much of the difference between the baseline case and the local control case is due to the sulfate component.

4. Additional Observations on the Results of the Local Measures Analyses

The application of control measures for the local measures analyses (with the exception of sulfur dioxide for Birmingham as noted previously) results in somewhat modest percentage and overall tons/year reductions. This is because a substantial part of local emissions is attributable to mobile sources, small business, and household activities for which practical, large-reduction, and quick-acting emissions reductions measures could not be identified at this time. A list of the control measures and their reduction potential is contained in the AQMTSD.

Preliminary analysis indicates that the reductions in SO_2 and NO_X required by today's proposed rule, if achieved through controls on EGUs, will have a lower cost per ton than most of the measures applied in the local measures study.

The EPA recognizes that the above analysis of the possible results of local control efforts is uncertain. It is not feasible at this time to identify with certainty the levels of emissions reductions from sources of regional transport and reductions from local measures that will lead to attainment of the PM standards. Much technical work remains as States develop their SIPs, including improvements in local emissions inventories, local area and subregional air quality analyses, and impact analysis of the effects and costs of local controls. At the same time, EPA believes that all of the available analyses of the effects of local measures support the reductions in transported pollutants that are addressed by today's proposal. Taken as a whole, the studies described above strongly support the need for the substantial reductions in transported pollutants that EPA is proposing.

At the same time, EPA believes that nothing in the local measures analysis should be interpreted as discouraging the development of urban-based control measures. Clearly, for many areas, attaining the $PM_{2.5}$ standard will require measures to address both local and regional transport. We encourage the development of early reduction measures, and specifically we note that the CAA requires States to analyze the control measures necessary to attain the standard as soon as possible.

We also note that the baseline emissions inventory used for this analysis has some known gaps. For example, direct $PM_{2.5}$ and VOXC commercial cooking (*e.g.*, charbroiling) are not included because no robust estimates were available for the 1996 base year used for this analysis. Also, excess $PM_{2.5}$ due to deterioration of engines in service, and emissions from open burning of refuse, may not be well represented. The effect of these omissions on our estimates of the number of areas reaching attainment is uncertain, but we do not believe the omissions affect our preliminary conclusions that transport controls are less expensive on a per ton basis, and are beneficial for attainment.

V. Air Quality Aspects of Significant Contribution for 8-Hour Ozone and Annual Average $PM_{2.5}$ Before Considering Cost

A. Introduction

In this section, we present the analyses of ambient data and modeling which support the findings in today's proposal on the air quality aspects of significant contribution (before considering cost) for 8-hour ozone and annual average $PM_{2.5}$. The analyses for ozone are presented first, followed by the analyses for $PM_{2.5}$. For both pollutants, we summarize information from non-EPA studies then present the procedures and findings from EPA's air quality modeling analyses of interstate transport for ozone and $PM_{2.5}$.

B. Significant Contribution to 8-Hour Ozone Before Considering Cost

1. Findings From Non-EPA Analyses That Support the Need for Reductions in Interstate Ozone Transport

As discussed in section II, it is a long-held scientific view that ground-level ozone is a regional, and not merely a local, air quality problem. Ozone and its precursors are often transported long distances across State boundaries exacerbating the downwind ozone problem. This transport of ozone can make it difficult—or impossible—for some States to meet their attainment deadlines solely by regulating sources within their own boundaries.

The EPA participated with States in the Eastern U.S. as well as industry representatives and environmental groups in the Ozone Transport Assessment Group (OTAG), which documented that long-distance transport of NO_X (a primary ozone precursor) across much of the OTAG study area contributed to high levels of ozone. For background on OTAG and the results from the study, see the following Web site: *http://www.epa.gov/ttn/naaqs/ozone/rto/otag/index.html*.

The air quality and modeling analyses by OTAG yielded the following major findings and technical conclusions relevant to today's proposed rulemaking:

• Air quality data indicate that ozone is pervasive, that ozone is transported, and that ozone aloft is carried over and transported from 1 day to the next.

• Regional NO_X reductions are effective in producing ozone benefits; the more NO_X reduced, the greater the benefit.

• Ozone benefits are greatest where emissions reductions are made; benefits decrease with distance.

• Elevated and low-level NO_X reductions are both effective.

• Volatile organic compounds (VOC) controls are effective in reducing ozone locally and are most advantageous to urban nonattainment areas. The OTAG report also recognized that VOC emissions reductions do not play much of a role in long-range transport, and concluded that VOC reductions are effective in reducing ozone locally and are most advantageous to urban nonattainment areas.

These OTAG findings provide technical evidence that transport within portions of the OTAG region results in large contributions from upwind States to ozone in downwind areas, and that a regional approach to reduce NO_X emissions is an effective means of addressing interstate ozone transport.

2. Air Quality Modeling of Interstate Ozone Contributions

This section documents the procedures used by EPA to quantify the impact of emissions in specific upwind States on air quality concentrations in projected downwind nonattainment areas for 8-hour ozone. These procedures are the first of the two-step approach for determining significant contribution, as described in section III, above.

The analytic approach for modeling the contribution of upwind States to ozone in downwind nonattainment areas is described in subsection (a), the methodology for analyzing the modeling results is presented in subsection (b), and the findings as to whether individual States make a significant contribution (before considering cost) to 8-hour ozone nonattainment is provided in subsection (c).

The air quality modeling for the interstate ozone contribution analysis was performed for those counties predicted to be nonattainment for 8-hour ozone in the 2010 Base Case, as described above in section IV.D. The procedures used by EPA to determine the air quality component of whether emissions in specific upwind States make a significant contribution (before considering cost) to projected downwind nonattainment for 8-hour ozone are the same as those used by EPA for the State-by-State determination in the NO_X SIP Call.

a. Analytical Techniques for Modeling Interstate Contributions to 8-Hour Ozone Nonattainment

The modeling approach used by EPA to quantify the impact of emissions in specific upwind States on projected downwind nonattainment areas for 8-hour ozone includes two different techniques, zero-out and source apportionment. The outputs of the two modeling techniques were used to calculate "metrics" or measures of contribution. The metrics were evaluated in terms of three key contribution factors to determine which States make a significant contribution (before considering cost) to downwind ozone nonattainment. Details of the modeling techniques and metrics are described in this section.

The zero-out and source apportionment modeling techniques provide different technical approaches to quantifying the downwind impact of emissions in upwind States. The zero-out modeling analysis provides an estimate of downwind impacts by comparing the model predictions from a base case run to the predictions from a run in which the base case man-made emissions are removed from a specific State. Zero-out modeling was performed by removing all man-made emissions of NO_X and VOC in the State.

In contrast to the zero-out approach, the source apportionment modeling quantifies downwind impacts by tracking the impacts of ozone formed from emissions in an upwind source area. For this analysis, the source apportionment technique was implemented to provide the contributions from all man-made sources of NO_X and VOC in each State. Additional information on the source apportionment technique can be found in the CAM_X User's Guide.[71] There is currently no technical evidence showing that one technique is clearly superior to the other for evaluating contributions to ozone from various emission sources; therefore, both approaches were given equal consideration in this analysis.

The EPA performed State-by-State zero-out modeling and source apportionment modeling for 31 States in the East. These States are as follows: Alabama, Arkansas, Connecticut, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, New Hampshire, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Vermont, Virginia, West Virginia, and Wisconsin. In both types of modeling, emissions from the District of Columbia were combined with those from Maryland. For the source apportionment modeling, North Dakota and South Dakota were aggregated into a single source region. Because large portions of the six States along the western border of the modeling domain (*i.e.*, Kansas, Nebraska, North Dakota, Oklahoma, South Dakota, and Texas) are outside the domain, EPA has deferred analyzing the contributions to downwind ozone nonattainment for these States.

The EPA selected several metrics to quantify the projected downwind contributions from emissions in upwind States. The metrics were designed to provide information on three fundamental factors for evaluating whether emissions in an upwind State make large and/or frequent contributions to downwind nonattainment. These factors are:

• The magnitude of the contribution,
• The frequency of the contribution, and
• The relative amount of the contribution.

The magnitude of contribution factor refers to the actual amount of ozone contributed by emissions in the upwind State to nonattainment in the downwind area. The frequency of the contribution refers to how often contributions above certain thresholds occur. The relative amount of the contribution is used to compare the total ozone contributed by the upwind State to the total amount of nonattainment ozone in the downwind area. The factors are the basis for several metrics that can be used to assess a particular impact. The metrics used in this analysis are the same as those used in the NO_X SIP Call. These metrics are described below for the zero-out modeling and for the source apportionment modeling. Table V–1 lists the metrics for each factor. Additional details with examples of the procedures for calculating the metrics are provided in the AQMTSD. We solicit comment on other metrics including whether it would be appropriate to develop a metric based on annualized costs for each State per ambient impact on each downwind nonattainment receptor.

TABLE V–1.—OZONE CONTRIBUTION FACTORS AND METRICS

Factor	Zero-out	Source apportionment
Magnitude of contribution	Maximum contribution	Maximum contribution; and Highest daily average contribution (ppb and percent).
Frequency of contribution	Number and percent of exceedances with contributions in various concentration ranges.	Number and percent of exceedances with contributions in various concentration ranges.
Relative amount of contribution	Total contribution relative to the total exceedance ozone in the downwind area and. Population-weighted total contribution relative to the total population-weighted exceedance ozone in the downwind area.	Total average contribution to exceedance hours in the downwind area.

[71] Environ, 2002: User's Guide to the Comprehensive Air Quality Model with Extensions (CAM_X), Novato, CA.

The values for each metric were calculated using only those periods during which model-predicted 8–hour average ozone concentration were of 85 ppb or more in at least one of the model grid cells that are associated with the receptor county. That is, we only analyzed interstate ozone contributions for the nonattainment receptor counties when the model predicted an exceedance in the 2010 Base Case. The procedures for assigning model grid cells to each nonattainment county are described in the AQMTSD.

As in the NO_X SIP Call, the ozone contribution metrics are calculated and evaluated for each upwind State to each downwind nonattainment receptor. These source-receptor pairs are referred to as "linkages."

b. Zero-Out Metrics

A central component of several of the metrics is the number of predicted exceedances in the 2010 Base Case for each nonattainment receptor. The number of exceedances in a particular nonattainment receptor is determined by the total number of daily predicted peak 8-hour concentrations of 85 ppb or more across all the episode days for the model grid cells assigned to the receptor.

The Maximum Contribution Metric for a particular upwind State to an individual downwind nonattainment receptor linkage is determined by first calculating the concentration differences between the 2010 Base Case and the zero-out simulation for that upwind State. This calculation is performed for all 2010 Base Case exceedances predicted for the downwind receptor. The largest difference (*i.e.*, contribution) for the linkage across all of the exceedances at the downwind receptor is the maximum contribution.

The Frequency of Contribution Metric for a particular linkage is determined by first sorting the contributions by concentration range (*e.g.*, 2 to 5 ppb, 5 to 10 ppb, etc.). The number of impacts in each range is used to assess the frequency of contribution.

Determining the Total Ozone Contribution Relative to the Base Case Exceedance Metric for a particular linkage involves first calculating the total ozone of 85 ppb or more in the 2010 Base Case and in the upwind State's zero-out run. The calculation is performed by summing the amount of ozone above the NAAQS for each predicted exceedance at the downwind receptor area. Finally, the amount of ozone above the NAAQS from the zero-out run is divided by the amount of ozone above the NAAQS from the 2010 Base simulation to form this metric.

The Population-Weighted Relative Contribution Metric is similar to the total ozone contribution metric described in the preceding paragraph, except that during the calculation the amount of ozone above the NAAQS in both the base case and the zero-out simulation is weighted by (*i.e.*, multiplied by) the 2000 population in the receptor county.

c. Source Apportionment Metrics

Despite the fundamental differences between the zero-out and source apportionment techniques, the definitions of the source apportionment contribution metrics are generally similar to the zero-out metrics. One exception is that all periods during the day with predicted 8-hour averages of 85 ppb or more are included in the calculation of source apportionment metrics, as opposed to just the daily peak 8-hour predicted values which are used for the zero-out metrics. Additional information on differences between the zero-out and source apportionment metrics calculations can be found in the AQMTSD.

The outputs from the source apportionment modeling provide estimates of the contribution to each predicted exceedance for each linkage. For a given upwind State to downwind nonattainment receptor linkage, the Maximum Contribution Metric is the highest contribution from among the contributions to all exceedances at the downwind receptor. The Frequency of Contribution Metric for the source apportionment technique is determined in a similar way to which this metric is calculated for the zero-out modeling.

The Highest Daily Average Contribution Metric is determined for each day with predicted exceedances at the downwind receptor. The metric is calculated by first summing the contributions for that linkage over all exceedances on a particular day, then dividing by the number of exceedances on that day to produce a daily average contribution to nonattainment. The daily average contribution values across all days with exceedances are examined to identify the highest value which is then selected for use in the determination of significance (before considering cost). We also express this metric as a percent by dividing the highest daily average contribution by the corresponding ozone exceedance concentration on the same day.

The Percent of Total Nonattainment Metric is determined for each of the three episodes individually as well as for all 30 days (*i.e.*, all three episodes) combined. This metric is calculated by first summing the contributions to all exceedances for a particular linkage to produce an estimate of the total contribution. Second, the total contribution is divided by the total ozone for periods above the NAAQS.

d. Evaluation of Upwind State Contributions to Downwind 8-Hour Ozone Nonattainment

The EPA compiled the 8-hour metrics by downwind area in order to evaluate the contributions to downwind nonattainment. The contribution data were reviewed to determine how large of a contribution a particular upwind State makes to nonattainment in each downwind area in terms of both the magnitude of the contribution, and the relative amount of the total contribution. The data were also examined to determine how frequently the contributions occur.

The first step in evaluating this information was to screen out linkages for which the contributions were very low. This initial screening was based on: (1) A maximum contribution of less than 2 ppb from either of the two modeling techniques and/or, (2) a percent of total nonattainment of less than 1 percent. Any upwind State that did not pass both of these screening criteria for a particular downwind area was considered not to make a significant contribution to that downwind area.

The finding of meeting the air quality component of significance (*i.e.*, before considering cost) for linkages that passed the initial screening criteria was based on EPA's technical assessment of the values for the three factors. Each upwind State that had large and/or frequent contributions to the downwind area, based on these factors, is considered as contributing significantly (before considering cost) to nonattainment in the downwind area. For each upwind State, the modeling disclosed a linkage in which all three factors—high magnitude of contribution, high frequency of contribution, high relative percentage of nonattainment—are met. In addition, each upwind State contributed to nonattainment problems in at least two downwind States (except for Louisiana and Arkansas which contributed to nonattainment in only Texas).[72] There have to be at least two different factors that indicate large and/or frequent contributions in order for the linkage to be significant (before considering cost).

[72] In some cases, we determined the contribution of some States to downwind problems as significant (before considering cost) because it passed two, but not all three, factors.

In this regard, the finding of a significant contribution (before considering cost) for an individual linkage was not based on any single factor. For most of the individual linkages, the factors yield a consistent result (*i.e.*, either large and frequent contributions and high relative contributions or small and infrequent contributions and low relative contributions). In some linkages, however, not all of the factors are consistent. The EPA believes that each of the factors provides an independent, legitimate measure of contribution.

The EPA applied the evaluation methodology described above to each upwind-downwind linkage to determine which States contribute significantly (before considering cost) to nonattainment in the 47 specific downwind counties. The analysis of the metrics for each linkage is presented in the AQMTSD. Of the 31 States included in the assessment of interstate ozone contributions, 25 States were found to have emissions which make a significant contribution (before considering cost) to downwind 8-hour ozone nonattainment. These States are listed in Tables V–2 and V–3. The linkages which EPA found to be significant (before considering cost) are listed in Tables V–2 (by upwind State) and V–3 (by downwind nonattainment county) for the 8-hour NAAQS. Of the 31 States included in the assessment of interstate ozone transport, the following six States are found to not make a significant contribution to downwind nonattainment: Florida, Maine, Minnesota, New Hampshire, Rhode Island, and Vermont.

TABLE V–2.—PROJECTED DOWNWIND COUNTIES TO WHICH SOURCES IN UPWIND STATES CONTRIBUTE SIGNIFICANTLY (BEFORE CONSIDERING COST) FOR THE 8-HOUR NAAQS.

Upwind state	Downwind 2010 nonattainment counties
AL	Crittenden AR, Fulton GA, Harris TX.
AR	Harris TX, Tarrant TX.
CT	Kent RI, Suffolk NY.
DE	Bucks PA, Camden NJ, Cumberland NJ, Delaware PA, Gloucester NJ, Hunterdon NJ, Mercer NJ, Middlesex NJ, Monmouth NJ, Montgomery PA, Morris NJ, Ocean NJ, Philadelphia PA, Richmond NY, Suffolk NY.
GA	Crittenden AR, Mecklenburg NC.
IA	Kenosha WI, Lake IN, Racine WI.
IL	Allegheny PA, Crittenden AR, Erie NY, Geauga OH, Kenosha WI, Lake IN, Racine WI, Sheboygan WI, Summit OH.
IN	Allegheny PA, Crittenden AR, Geauga OH, Kenosha WI, Racine WI, Sheboygan WI, Summit OH.
KY	Allegheny PA, Crittenden AR, Fulton GA, Geauga OH.
LA	Harris TX, Tarrant TX.
MA	Kent RI, Middlesex CT.
MD	Arlington VA, Bergen NJ, Bucks PA, Camden NJ, Cumberland NJ, Delaware PA, Erie NY, Fairfax VA, Fairfield CT, Gloucester NJ, Hudson NJ, Hunterdon NJ, Mecklenburg NC, Mercer NJ, Middlesex CT, Middlesex NJ, Monmouth NJ, Montgomery PA, Morris NJ, New Haven CT, Newcastle DE, Ocean NJ, Philadelphia PA, Putnam NY, Richmond NY, Suffolk NY, Summit OH, Washington DC, Westchester NY.
MI	Allegheny PA, Anne Arundel MD, Baltimore MD, Bergen NJ, Bucks PA, Camden NJ, Cecil MD, Cumberland NJ, Delaware PA, Erie NY, Geauga OH, Gloucester NJ, Harford MD, Hudson NJ, Hunterdon NJ, Kenosha WI, Kent MD, Lake IN, Mercer NJ, Middlesex NJ, Monmouth NJ, Montgomery PA, Morris NJ, Newcastle DE, Ocean NJ, Philadelphia PA, Prince Georges MD, Racine WI, Richmond NY, Suffolk NY, Summit OH.
MO	Crittenden AR, Geauga OH, Kenosha WI, Lake IN, Racine WI, Sheboygan WI.
MS	Crittenden AR, Harris TX.
NC	Anne Arundel MD, Baltimore MD, Camden NJ, Cecil MD, Cumberland NJ, Fulton GA, Gloucester NJ, Harford MD, Kent MD, Newcastle DE, Ocean NJ, Philadelphia PA, Suffolk NY.
NJ	Bucks PA, Delaware PA, Erie NY, Fairfax VA, Fairfield CT, Kent RI, Middlesex CT, Montgomery PA, New Haven CT, Philadelphia PA, Putnam NY, Richmond NY, Suffolk NY, Westchester NY.
NY	Fairfield CT, Hudson NJ, Kent RI, Mercer NJ, Middlesex CT, Middlesex NJ, Monmouth NJ, Morris NJ, New Haven CT.
OH	Allegheny PA, Anne Arundel MD, Arlington VA, Baltimore MD, Bergen NJ, Bucks PA, Camden NJ, Cecil MD, Cumberland NJ, Delaware PA, Fairfax VA, Fairfield CT, Gloucester NJ, Harford MD, Hudson NJ, Hunterdon NJ, Kenosha WI, Kent MD, Kent RI, Lake IN, Mercer NJ, Middlesex CT, Middlesex NJ, Monmouth NJ, Montgomery PA, Morris NJ, New Haven CT, Newcastle DE, Ocean NJ, Philadelphia PA, Prince Georges MD, Racine WI, Richmond NY, Suffolk NY, Washington DC, Westchester NY.
PA	Anne Arundel MD, Arlington VA, Baltimore MD, Bergen NJ, Camden NJ, Cecil MD, Cumberland NJ, Erie NY, Fairfax VA, Fairfield CT, Gloucester NJ, Harford MD, Hudson NJ, Hunterdon NJ, Kenosha WI, Kent MD, Kent RI, Lake IN, Mecklenburg NC, Mercer NJ, Middlesex CT, Middlesex NJ, Monmouth NJ, Morris NJ, New Haven CT, Newcastle DE, Ocean NJ, Prince Georges MD, Putnam NY, Racine WI, Richmond NY, Suffolk NY, Summit OH, Washington DC, Westchester NY.
SC	Fulton GA, Mecklenburg NC.
TN	Crittenden AR, Fulton GA, Lake IN, Mecklenburg NC, Tarrant TX.
VA	Anne Arundel MD, Baltimore MD, Bergen NJ, Bucks PA, Camden NJ, Cecil MD, Cumberland NJ, Delaware PA, Erie NY, Fairfield CT, Gloucester NJ, Harford MD, Hudson NJ, Hunterdon NJ, Kent MD, Kent RI, Lake IN, Mecklenburg NC, Mercer NJ, Middlesex CT, Middlesex NJ, Monmouth NJ, Montgomery PA, Morris NJ, New Haven CT, Newcastle DE, Ocean NJ, Philadelphia PA, Prince Georges MD, Putnam NY, Richmond NY, Suffolk NY, Summit OH, Washington DC, Westchester NY.
WI	Erie NY, Lake IN.
WV	Allegheny PA, Anne Arundel MD, Baltimore MD, Bucks PA, Camden NJ, Cecil MD, Cumberland NJ, Delaware PA, Fairfax VA, Fairfield CT, Fulton GA, Gloucester NJ, Harford MD, Hunterdon NJ, Kent MD, Mercer NJ, Middlesex NJ, Monmouth NJ, Montgomery PA, Morris NJ, New Haven CT, Newcastle DE, Ocean NJ, Philadelphia PA, Prince Georges MD, Suffolk NY, Summit OH, Washington DC, Westchester NY.

TABLE V–3.—UPWIND STATES THAT CONTAIN EMISSIONS SOURCES THAT CONTRIBUTE SIGNIFICANTLY (BEFORE CONSIDERING COST) TO PROJECTED 8-HOUR NONATTAINMENT IN DOWNWIND STATES.

Downwind nonattainment counties	Upwind States									
Crittenden AR	AL	GA	IL	IN	KY	MO	MS	TN		
Fairfield CT	MD	NJ	NY	OH	PA	VA	WV			
Middlesex CT	MA	MD	NJ	NY	OH	PA	VA			
New Haven CT	MD	NJ	NY	OH	PA	VA	WV			
Washington DC	MD	OH	PA	VA	WV					
Newcastle DE	MD	MI	NC	OH	PA	VA	WV			
Fulton GA	AL	KY	NC	SC	TN	WV				
Lake IN	IA	IL	MI	MO	OH	PA	TN	VA	WI	
Anne Arundel MD	MI	NC	OH	PA	VA	WV				
Baltimore MD	MI	NC	OH	PA	VA	WV				
Cecil MD	MI	NC	OH	PA	VA					
Harford MD	MI	NC	OH	PA	VA	WV				
Kent MD	MI	NC	OH	PA	VA	WV				
Prince Georges MD	MI	OH	PA	VA	WV					
Mecklenburg NC	GA	MD	SC	TN	VA					
Bergen NJ	MD	MI	OH	PA	VA					
Camden NJ	DE	MD	MI	NC	OH	PA	VA	WV		
Cumberland NJ	DE	MD	MI	NC	OH	PA	VA	WV		
Gloucester NJ	DE	MD	MI	NC	OH	PA	VA	WV		
Hudson NJ	MD	MI	NY	OH	PA	VA				
Hunterdon NJ	DE	MD	MI	OH	PA	VA	WV			
Mercer NJ	DE	MD	MI	NY	OH	PA	VA	WV		
Middlesex NJ	DE	MD	MI	NY	OH	PA	VA	WV		
Monmouth NJ	DE	MD	MI	NY	OH	PA	VA	WV		
Morris NJ	DE	MD	MI	NY	OH	PA	VA	WV		
Ocean NJ	DE	MD	MI	NC	OH	PA	VA	WV		
Erie NY	IL	MD	MI	NJ	PA	VA	WI			
Putnam NY	MD	NJ	PA	VA						
Richmond NY	DE	MD	MI	NJ	OH	PA	VA			
Suffolk NY	CT	DE	MD	MI	NC	NJ	OH	PA	VA	WV
Westchester NY	MD	NJ	OH	PA	VA	WV				
Geauga OH	IL	IN	KY	MI	MO					
Summit OH	IL	IN	MD	MI	PA	VA	WV			
Allegheny PA	IL	IN	KY	MI	OH	WV				
Bucks PA	DE	MD	MI	NJ	OH	VA	WV			
Delaware PA	DE	MD	MI	NJ	OH	VA	WV			
Montgomery PA	DE	MD	MI	NJ	OH	VA	WV			
Philadelphia PA	DE	MD	MI	NC	NJ	OH	VA	WV		
Kent RI	CT	MA	NJ	NY	OH	PA	VA			
Denton TX	None of the upwind States examined in this analysis were found to make a significant contribution (before considering cost) to this nonattainment receptor.									
Harris TX	AL	AR	LA	MS						
Tarrant TX	AR	LA	TN							
Arlington VA	MD	OH	PA							
Fairfax VA	MD	NJ	OH	PA	WV					
Kenosha WI	IA	IL	IN	MI	MO	OH	PA			
Racine WI	IA	IL	IN	MI	MO	OH	PA			
Sheboygan WI	IL	IN	MO							

C. Significant Contribution for Annual Average $PM_{2.5}$ Before Considering Cost

1. Analyses of Air Quality Data That Support the Need To Reduce Interstate Transport of $PM_{2.5}$

a. Spatial Gradients of Pollutant Concentrations

Daily maps of $PM_{2.5}$ mass concentrations from EPA's national monitoring network show large areas of elevated $PM_{2.5}$ occurring over monitoring locations in urban areas as well as rural areas. The fact that many of the rural monitors are not located near emissions sources, or at least not near large emission sources, and yet the rural concentrations are elevated like the neighboring urban concentrations, provides evidence that $PM_{2.5}$ is being transported to the rural areas.

When the daily maps of $PM_{2.5}$ mass concentrations are viewed in sequence, they show the large areas of elevated $PM_{2.5}$ moving from one area to another, suggesting that $PM_{2.5}$ is being transported not just from urban areas to neighboring rural areas, but also from one State to another and from one part of the country to another. The smoke from wildfires in southeastern Ontario reaching all of the New England States in July of 2002 is but one well-publicized example of transported $PM_{2.5}$.

It may be suggested that it is not $PM_{2.5}$ that is being transported; rather, it is meteorological conditions conducive to $PM_{2.5}$ formation that are being transported. However, the fact that the monitors located far from emission sources often report elevated $PM_{2.5}$ just after the upwind monitors record high levels and just before the downwind monitors record high levels indicates strongly that it is $PM_{2.5}$ that is being transported.

Episodes of movement of elevated $PM_{2.5}$ have been seen in almost every direction in the Eastern United States, including in the west to east direction along the lower Great Lakes, in the south to north direction along the East Coast, in the south to north direction across the Midwestern States, in the north to south direction across the Midwestern States, and in the north to south direction along the East Coast. More information on episodes of movement of $PM_{2.5}$ is contained in the Air Quality Data Analysis Technical Support Document.

Satellite data from Moderate Resolution Imaging Spectroradiometer (MODIS) sensors, designed to retrieve aerosol properties over both land and ocean, are strongly correlated with the ground-based monitors that measure $PM_{2.5}$ concentrations below. The MODIS data provide a visual corroboration for the above described regional transport. Three examples follow:[73]

Midwest-Northeast Haze Event: June 20–28, 2002

During late June 2002, the Central and Eastern United States experienced a haze event from a combination of man-made air pollutants combined with some smoke. The MODIS images document the buildup of aerosols in the Midwest from June 20–22, then the transport of aerosols across the Northeast from June 23–26. Images from June 27 and 28 show the beginning of smoke transported from fires in Canada into the Northern Midwest. This series from June 20–26 qualitatively documents a haze transport event from the Midwest into the Northeast. The imagery also documents the geographical scale of the smoke transport on June 27–28.

Northeast Fire Event: July 4–9, 2002

In early July 2002, the MODIS imagery captured two events: an episodic widespread haze event in the East, Southeast, and Midwest; and an event directly related to major forest fires in Canada. On July 4 and 5, MODIS images show urban haze in the East, Southeast, and Midwest. This haze event persists in the Southeast and southern Midwest throughout the remaining days, July 7–9. At the same time, MODIS images for July 6 through July 8 document how the Northeast and mid-Atlantic become dominated by smoke transported into the region from Canada fires. On July 9, MODIS images show the smoke and the southern haze has moved towards the east while dissipating over the Atlantic. This series from July 6–8 qualitatively documents the smoke transport event from major fires in Canada. The imagery also documents the widespread geographical scale of haze, particularly from July 4–8, as well as the movement of the haze (along with smoke) across large distances.

Midwest-Southeast Haze Event: September 8–14, 2002

This imagery during September 2002 reveals the formation of a large-scale haze event over the lower Ohio River Valley that eventually transports over large portions of Southcentral and Southeastern United States. The MODIS images document the buildup of aerosols in the Midwest over September 8 and 9. Influenced by a strong low-pressure system off the mid-Atlantic seaboard on September 10, the haze plume divides, with the majority traveling south and west toward Texas and a small remnant moving northeast. On September 11 and 12, the Midwest plume, combined with additional pollutants from Texas and the Southeast, is transported to the East. September 13 has another low pressure system, forcing collection of pollutants in Texas and Louisiana, which are obscured by cloud cover on September 14. This series reveals the geographic extent and the complexities that are possible with the transfer of pollutants. More information on the use of satellite data to observe the movement of $PM_{2.5}$ is contained in the Air Quality Data Analysis Technical Support Document.

b. Urban vs. Rural Concentrations

Differences between concentrations at urban areas and nearby rural locations help indicate the general magnitudes of regional and local contributions to $PM_{2.5}$ and $PM_{2.5}$ species.[74] The differences indicate that in the Eastern United States, the regional contributions to the annual average concentrations at urban locations is 50 to 80 percent which, in terms of mass, is generally between 10 and 13 μg/m^3. For many rural areas, average $PM_{2.5}$ concentrations exceed 10 μg/m^3 and are often not much below the annual $PM_{2.5}$ NAAQS of 15 μg/m^3. These results are consistent with those found in the NARSTO Fine Particle Assessment.[75] More information on comparisons of urban and rural concentrations of $PM_{2.5}$ is contained in the Air Quality Data Analysis Technical Support Document.

For the most part, sulfate is regionwide, as indicated by the rural sulfate concentrations being 80 to 90 percent of the urban sulfate concentrations. Total carbon is less of a regional phenomenon than sulfate, as evidenced by the rural total carbon concentrations being about 50 percent of the urban total carbon concentrations. Last, nitrate has a regional component; however, the local component can be as large as 2.0 μg/m^3.

c. Inter-Site Correlation of $PM_{2.5}$ Mass and Component Species

Correlation analysis provides further evidence for the transport of $PM_{2.5}$ and its constituents. Analysis of the time series history of $PM_{2.5}$ among different monitoring locations indicates a strong tendency for $PM_{2.5}$ concentrations to rise and fall in unison. Correlations of $PM_{2.5}$ daily concentrations among stations separated by over 300 to 500 kilometers frequently have correlation coefficients that exceed 0.7. The correlation coefficient is a measure of the degree of linear association between two variables, and the square of the correlation coefficient, denoted R^2, measures how much of the total variability in the data is explained by a simple linear model. For example, in the preceding case, approximately 50 percent, $(0.7)^2$, of the variability in $PM_{2.5}$ concentrations at one site frequently can be explained by $PM_{2.5}$ concentrations at a site over 300 kilometers away. These high correlations occur both in warm and cool seasons suggesting that large scale transport phenomenon in conjunction with large and small scale meteorological conditions play a major role in particle concentration changes over large geographic areas.

Correlation of major $PM_{2.5}$ constituents among monitoring stations show differing patterns as distance separating monitors increases. For sulfate, the correlation among daily average concentrations remains strong (above 0.7) at distances exceeding 300 kilometers. Correlation of nitrates among monitoring stations tends to be lower than for sulfate and also varies somewhat among seasons. Warm season correlations, when nitrates are lowest, tend to be relatively low (about 0.4) for stations separated by 300 kilometers or more. Cool season correlations for nitrates are larger than warm season correlations and range from about 0.5 to above 0.6 for stations near urban areas and separated by 300 kilometers or more. Correlation coefficients for organic carbon typically range from about 0.4 to above 0.6 for separation

[73] Battelle, *Satellite Data for Air Quality Analysis.* July 2003.

[74] Rao, Tesh, *Chemical Speciation of* $PM_{2.5}$ *in Urban and Rural Areas,* Published in the Proceedings of the Air and Waste Management Symposium on Air Quality Measurement Methods and Technology—2002, November 2002.

[75] North American Research Strategy for Tropospheric Ozone and Particulate Matter, *Particulate Matter Science for Policy Makers—A NARSTO Assessment.* February 2003.

distances above 300 kilometers but appear to decrease more rapidly during the summer season compared with the other three seasons. For elemental carbon and crustal material, correlation with distance drops very rapidly to values below 0.2 or 0.3 for separation distances above 50 to 100 kilometers.

The formation rate and relative stability for the major $PM_{2.5}$ species help explain the observed correlation patterns. For sulfate, conversion of SO_2 to sulfate occurs slowly over relatively large distances downwind of major emission sources of SO_2. Slow conversion of SO_2 to sulfate over large travel distances promotes greater spatial homogeneity and thus large correlation among distant monitoring stations. For nitrates, evidence suggests that higher inter-station correlations in winter are associated with increased stability of nitrate (longer travel distances) when conditions are cool compared with warm seasons when nitrates are much less stable. The formation of secondary organic carbon from natural sources helps maintain a relatively homogeneous regional component (higher correlation) that is offset somewhat by higher organic carbon in urban areas associated with local carbon sources. For elemental carbon and crustal material, almost all of the contributions come from nearby sources and hence the relatively low correlation among stations that are separated by even small distances. More information on inter-site correlation of $PM_{2.5}$ and species is contained in the Air Quality Data Analysis Technical Support Document.

d. Ambient Source Apportionment Studies

Generally, sources emitting particulate matter, or precursors that later form particulate matter, emit multiple species of particulate matter simultaneously. Often, the proportions of the species are sufficiently different from one source type to another that it is possible to determine how much each source type contributes to the $PM_{2.5}$ mass observed at a monitoring location. This technique is called source apportionment or receptor modeling.

A review of nearly 20 recently published articles using source apportionment modeling at over 35 locations in the Eastern United States was conducted to understand commonalities and differences in source apportionment results.[76] A large sulfate dominated source was identified as the largest or one of the largest source types in nearly every study. Some studies labeled this source coal combustion, while others labeled it secondary sulfate and did not attribute it to an emission source. For many of the locations, over 50 percent of the $PM_{2.5}$ mass is apportioned to this source type during some seasons. Summer is typically the season with the largest contributions. Most of the studies, by using back trajectory analysis, indicated that the probable location of the sulfate/coal combustion sources is in the Midwest. Also, studies with multiple years of data tended to identify a winter and summer signature of the sulfate source type, with more mass being apportioned to the summer version. Reasons cited in these studies for the two signatures included different types of coal being burned during the summer versus the winter or different atmospheric chemistry leading to different proportions of species at the monitoring location by season.

A nitrate-dominated source type was identified at approximately half the sites and contributes to between 10 and 30 percent of the annual $PM_{2.5}$ mass. The source has seasonal variation with maxima in the cold seasons. The back trajectories sometimes point to areas with high ammonia emissions. However, the interpretation of this nitrate-dominated source type is not consistent from study to study. Some authors associate this source type with NO_X point sources and motor vehicles from major cities that are sufficiently far from the receptor for the NO_X to oxidize and react with ammonia. Other authors associate this source type with mobile emissions from nearby highways. One author does not interpret the source type since he believes it is artificially created by the meteorological conditions and atmospheric chemistry required for formation of ammonium nitrate.

Another major source type identified at nearly all the sites is one dominated by secondary organic matter. Some studies labeled this source motor vehicles, while other studies labeled it secondary organic matter and did not attribute it to an emission source. For several sites, this source type contributes more than 20 percent of the annual $PM_{2.5}$ mass. Only a few studies separated the source type into the combustion of gasoline and diesel fuel, and this separation was generally accomplished by using the four organic carbon fractions and the three elemental carbon fractions available from the IMPROVE network. In Washington, DC, over 85 percent of the mobile source type contribution is associated with gasoline vehicles and less than 15 percent with diesel. This contrasts with Atlanta, where only 33 to 55 percent (depending on the study) of the mobile source type contribution is associated with gasoline vehicles.

Wood smoke and forest fires were identified as a significant source type at several sites. The magnitude of their contributions varies from site to site. For a rural site in Vermont, the magnitude of the contribution of this source type is approximately 1 $\mu g/m^3$, which is approximately 15 percent of the total $PM_{2.5}$ mass. For Atlanta, the magnitude of contribution ranged from 0.5 to 2.0 $\mu g/m^3$ depending on the study, which is approximately 3 to 11 percent of the total $PM_{2.5}$ mass.

A crustal source category is identified for all sites and usually comprises 1 to 3 percent of the total $PM_{2.5}$ mass.

In addition to reviewing the source apportionment results in the published literature, EPA conducted receptor modeling using the data from the EPA speciation network to identify and quantify major contributors to $PM_{2.5}$ in eight urban areas: Houston, Birmingham, Charlotte, St. Louis, Indianapolis, Washington, DC, Milwaukee, and New York City.[77] The "8 city report" contains 2 general types of findings that provide evidence to support that interstate transport of fine particles occurs. First, the source apportionment analyses at the eight cities provides evidence of the types of sources that are most likely the major contributors to fine particle mass in each city. Second, linking wind trajectories with the source apportionment analyses provides evidence of the most likely locations of the source types that are the major contributors to fine particle mass in each city.

The source apportionment results identify the largest source type at each site to be coal combustion. The source type contains a large amount of sulfate and is a major source of selenium, a trace particle normally associated with the combustion of coal. The mass apportioned to this source type ranged from a low of 1 to 3 $\mu g/m^3$ in the lowest season to more than 10 $\mu g/m^3$ in the high seasons at 5 of the sites. The source type accounted for 30 to 50 percent of the overall mass, consistent with the proportions found in the published literature. The consistency in the relative and absolute magnitude in the contributions from the coal combustion source type in these eight cities, combined with the fact that the distance of major coal combustion sources from each city varies widely, indicates that it

[76] Battelle, *Compilation of Existing Studies of Source Apportionment for* $PM_{2.5}$. August 2003.

[77] Battelle, *Eight Site Source Apportionment of* $PM_{2.5}$ *Specification Trends Data*. September 2003.

is most likely a regional source rather than a local source.

The second and third largest source types are an ammonium nitrate source type and mobile sources. As the name implies, the ammonium nitrate source type contains a large amount of both ammonium and nitrate. Association of actual emission sources with this source type is less definitive, as was the case in the published literature. It is most likely that the source type originates from both coal combustion and mobile emissions. The mass apportioned to this source type ranged from 1 to 5 $\mu g/m^3$, which is 8 to 30 percent of the overall mass. This source type was identified in each city except Houston.

The absolute and relative magnitude of contribution from this source type showed much more variation than the coal combustion source type. It was highest in the Midwest in the winter, contributing between 7 and 10 $\mu g/m^3$, where the temperatures are cooler and there are more ammonia emissions. The summertime contributions of this source type are generally low, near 1 $\mu g/m^3$.

The mobile source type contains a large amount of organic carbon, some elemental carbon, very little sulfate and some metals (particularly barium from brake pads). The mass apportioned to this source type ranged from a low of 2.5 $\mu g/m^3$ at Milwaukee to a high of 6.5 $\mu g/m^3$ at Birmingham. This source type has the least seasonal variability of the largest source types. Contributions for the highest season, which varies from site to site but is generally fall or summer, are only 1.5 or 2 times higher than the contributions for the lowest season. As a percentage of mass, the mobile source type accounts for 15 to 40 percent of the total mass. It is assumed that most of the mass apportioned to the mobile source type is associated with local sources.

Linking the wind trajectories with the source apportionment results allows us to develop source regions (*i.e.*, geographic regions with a high probability of being the origin of the mass associated with a source profile). These source regions provide evidence that at least some of the particles associated with the source profiles are likely transported over long distances. For example, the highest probability source region for the coal combustion source profile for Birmingham includes parts of the following States: Missouri, Illinois, Indiana, Ohio, Kentucky, Virginia, North Carolina, South Carolina, Alabama, and Mississippi. Table V–4 lists the States included in the highest probability source regions for each of the three largest source profiles at each of the 8 sites.

The EPA compared the source regions for the coal combustion source (the largest source in each city) with the results from the zero-out modeling (described below) at the six cities in the 8 City Source Apportionment Study that were projected to violate the $PM_{2.5}$ standard in 2010. To perform these comparisons, for each city, the States in the highest probability source regions were compared to the States with a maximum contribution of 0.10 $\mu g/m^3$ or greater at the monitor in that city. These comparisons were generally good. At the Bronx site for instance, 8 of the 9 States with a maximum contribution of 0.10 $\mu g/m^3$ or greater were included in the highest probability source region for the coal combustion source. In 5 of the 6 cities for which the comparison was performed, at least two thirds of the States with a maximum contribution of 0.10 $\mu g/m^3$ were also in the highest probability source region for the coal combustion source. In the 6th city, St. Louis, 7 of the 13 States with a maximum contribution of 0.10 $\mu g/m^3$ were the highest probability source region for the coal combustion source. In summary, the general agreement between these two independent methods (source apportionment linked with wind trajectories and zero-out modeling) produce similar results in determining what States impact downwind receptors.

Sulfate is generally formed in the atmosphere from SO_2 (which is why the source is often referred to as secondary sulfate). Since the major sources of SO_2 emissions are utility plants, which are fairly well inventoried, the sulfate source locations have been compared to the utility plant SO_2 emissions as a check on the source identifications. Similarly, much of the nitrate is formed from NO_X reactions in the atmosphere with utility plants being a major source of NO_X. Hence, the nitrate source locations have also been compared with utility plant NO_X emissions inventories (although we do not expect the correlation to be as good because (a) nitrate is semi-volatile, (b) there are other significant sources of NO_X, and (c) the nitrate formation is also dependent on NH_3 emissions).

The comparisons of the sulfate source regions with the utility SO_2 emissions were good for some of the sites. At the Bronx site for instance, the back trajectories do yield the expected source region associations with large utility emissions of SO_2, namely the Ohio River Valley and the borders of Ohio, West Virginia, and Pennsylvania.

Comparisons of the contour maps of the various non-marine nitrate sources show a common pattern, namely Midwest farming regions. Illinois, in particular, stands out. It has both NO_X utility emissions and the farming regions for sources of ammonia.

More information on ambient source apportionment studies is contained in the Air Quality Data Analysis Technical Support Document.

TABLE V–4.—EIGHT CITY SOURCE APPORTIONMENT STUDY STATES IN HIGHEST PROBABILITY REGIONS FOR LARGEST SOURCES

Eight city source apportionment study states in highest probability regions for largest sources			
City	Coal combustion source	Mobile sources	Ammonium nitrate source
Bronx	NY, PA, MD, VA, NC, WV, OH, KY, IN, MI, IL, WI.	VT, MA, NY, NJ, PA, MD, VA, OH, IN, IL, WI, MN.	NY, NJ, DE, MD, VA, NC, PA, OH, IL, WI, MN.
Washington, DC	NY, PA, VA, NC, SC, GA, OH, KY, TN, IN, IL, AR.	MD, DE, VA, NC, SC, WV, OH, KY, TN.	NY, PA, MD, DE, KY, TN, IL.
Charlotte	NY, CT, NJ, PA, MD, VA, NC, SC, GA, FL, WV, OH, KY, MI, IN, AL, MS.	NC, SC, GA, TN AR	PA, MD, VA, NC, SC, GA, FL, KY, TN, AR, MO, KS.
Birmingham	VA, NC< SC, GA, FL, OH, KY, TN, AL, IN, IL, MO.	NC, SC, GA, AL, MS, AR	IN, KY, TN, IL, MS, MN, IA, AR, LA, NE, OK, TX.
Milwaukee	OH, MI, IN, KY, TN, AL, MS, IL, WI, IA, MO, AR, LA, SD, NE, KS, OK.	AL, WI, TN, MS, MN, MO	MI, OH, IN, WI, IL, MN, IA, MO, AR, ND, KS, OK.

TABLE V–4.—EIGHT CITY SOURCE APPORTIONMENT STUDY STATES IN HIGHEST PROBABILITY REGIONS FOR LARGEST SOURCES—Continued

City	Eight city source apportionment study states in highest probability regions for largest sources		
	Coal combustion source	Mobile sources	Ammonium nitrate source
Indianapolis	NC, KY, TN, AL, FL, IN, IL, IA, MO, AR, LA, TX, NE, KS.	OH, KY, TN, NC, GA, IN, MI, WI, AR, LA.	MI, OH, IN, WI, IL, MN, IA, MO, AR, ND, KS, OK.
St. Louis	WV, MI, KY, TN, IL, MO, AR, LA, TX.	MO, LA, NE, KS	OH, IN, KY, TN, IL, IA, KS.
Houston [1]	SC, GA, FL, AL, MS, LA, TX, IN ..	KY, TN, AL, MS, IN, IL, AR, LA, TX.	

[1] No ammonium nitrate source was identified in Houston.

2. Non-EPA Air Quality Modeling Analyses Relevant to $PM_{2.5}$ Transport and Mitigation Strategies

Air quality modeling was performed as part of the Southern Appalachian Mountains Initiative (SAMI) to support an assessment of the impacts of aerosols, ozone, and acid deposition in Class I areas within an eight-State portion of the Southeast.[78] The results of the SAMI modeling[79] provide the following technical information on transport relevant to today's proposal:

• Emissions reductions strategies produce the largest changes in fine particle mass on days with the highest mass.

• Most of the reductions in fine particle mass are due to reductions in sulfate particles.

• Particle mass in Class I areas of the SAMI region are influenced most by SO_2 emissions within the State and within adjacent States.

• SO_2 emissions in other regions outside SAMI also contribute to particle mass at Class I areas in the SAMI States.

• Specifically, in a 2010 baseline scenario, SO_2 emissions reductions in States outside the SAMI region accounted for approximately 20 percent to as much as 60 percent of the modeled sulfate reduction in the 10 Class 1 areas in the SAMI region.

• The relative sensitivity of nitrate fine particle mass at the SAMI Class I areas to changes in NO_X emissions from SAMI States and from other regions is similar to the above findings for sulfate fine particle mass.

• For SAMI to accomplish its mission, emissions reductions are essential both inside and outside the SAMI region.

• Formation of nitrate particles is currently limited in the rural southeastern U.S. by the availability of ammonia. As sulfate particles are reduced, more ammonia will be available to react with nitric acid vapor and form nitrate particles.

The findings of the air quality modeling performed by SAMI are very consistent and supportive of EPA's zero-out modeling, as described below. The findings indicate that interstate transport results in non-trivial contributions to $PM_{2.5}$ in downwind locations. High concentrations of $PM_{2.5}$ at sensitive downwind receptors are not only influenced by emissions within that State, but are also heavily influenced by emissions in adjacent States as well as emissions from States in other regions. The SAMI results support a regional control approach involving SO_2 emissions reductions in order to sufficiently reduce $PM_{2.5}$ to meet environmental objectives. The SAMI also found that SO_2 emissions reductions can lead to an increase in particle nitrate (*i.e.*, nitrate replacement). As described in section II.B.3, any such increases could be mitigated through reductions in emissions of NO_X.

3. Air Quality Modeling of Interstate $PM_{2.5}$ Contributions

This section documents the procedures used by EPA to quantify the impact of emissions in specific upwind States on projected downwind nonattainment for annual average $PM_{2.5}$. These procedures are part of the two-step approach for determining significant contribution, as described in section III, above.

The analytic approach for modeling the contribution of upwind States to $PM_{2.5}$ in downwind nonattainment areas and the methodology for analyzing the modeling results are described in subsection (a) and the findings as to whether individual States meet the air quality prong of the significant contribution test is provided in subsection (b). The air quality modeling for the interstate $PM_{2.5}$ contribution analysis was performed for those counties predicted to be nonattainment for annual average $PM_{2.5}$ in the 2010 Base Case, as described above in section IV.E.

a. Analytical Techniques for Modeling Interstate Contributions to Annual Average $PM_{2.5}$ Nonattainment

The EPA performed State-by-State zero-out modeling to quantify the contribution from emissions in each State to future $PM_{2.5}$ nonattainment in other States and to determine whether that contribution meets the air quality prong (*i.e.*, before considering cost) of the "contribute significantly" test. As part of the zero-out modeling technique we removed the 2010 Base Case man-made emissions of SO_2 and NO_X for 41 States on a State-by-State basis in different model runs. The States EPA analyzed using zero-out modeling are: Alabama, Arkansas, Colorado, Connecticut, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Montana, Nebraska, New Hampshire, New Mexico, New Jersey, New York, North Carolina, North Dakota, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, South Dakota, Tennessee, Texas, Vermont, Virginia, West Virginia, Wisconsin, and Wyoming. Emissions from the District of Columbia were combined with those from Maryland.

The contribution from each State to $PM_{2.5}$ at nonattainment receptors in other States was determined in the following manner:

Step 1: The $PM_{2.5}$ species predictions from the zero-out run were applied using the SMAT to calculate $PM_{2.5}$ at the 57 2010 Base Case nonattainment receptor counties. These receptors are identified in section IV.E.3, above.

Step 2: For each of the 57 receptors, we calculated the difference in $PM_{2.5}$ between the 2010 Base Case and the zero-out run. This difference is the

[78] The eight States of the Southern Appalachians covered by SAMI are: Alabama, Georgia, Kentucky, North Carolina, South Carolina, Tennessee, Virginia, and West Virginia.

[79] Southern Appalachian Mountains Initiative Final Report, August 2002.

contribution from the particular State to the downwind nonattainment receptor.

As described above in section V.B.2., EPA used three fundamental factors for evaluating the contribution of upwind States to downwind 8-hour ozone nonattainment, *i.e.*, the magnitude, frequency, and relative amount of contribution. One of these factors, the frequency of contribution, is not relevant for an annual average NAAQS and thus, frequency was not considered in the evaluation of interstate contributions to nonattainment of the $PM_{2.5}$ NAAQS.

The EPA considered a number of metrics to quantify the magnitude and relative amount of the $PM_{2.5}$ contributions. All of the metrics are described in the AQMTSD. As discussed in section III, above, EPA is proposing to use the maximum downwind contribution metric as the means for evaluating the significance (before considering cost) of interstate $PM_{2.5}$ transport. We solicit comment on other metrics including population-weighted metrics and whether it would be appropriate to develop a metric based on annualized costs for each State per ambient impact on each downwind nonattainment receptor.

The procedures for calculating the maximum contribution metric are as follows:

Step 1: Determine the contribution from each upwind State to $PM_{2.5}$ at each downwind receptor;

Step 2: The highest contribution from among those determined in Step 1 is the maximum downwind contribution.

b. Evaluation of Upwind State Contributions to Downwind $PM_{2.5}$ Nonattainment

The EPA is proposing to use a criterion of 0.15 $\mu g/m^3$ for determining whether emissions in a State make a significant contribution (before considering cost) to $PM_{2.5}$ nonattainment in another State. The rationale for choosing this criterion is described in section III, above. The maximum downwind contribution from each upwind State to a downwind nonattainment county is provided in Table V–5. Of the States analyzed for this proposal, 28 States and the District of Columbia contribute 0.15 $\mu g/m^3$ or more to nonattainment in other States and therefore are found to make a significant contribution (before considering cost) to $PM_{2.5}$. Although we are proposing to use 0.15 $\mu g/m^3$ as the air quality criterion, we have also analyzed the impacts of using 0.10 $\mu g/m^3$. Based on our current modeling, two additional States, Oklahoma and North Dakota, would be included if we were to adopt 0.10 $\mu g/m^3$ as the air quality criterion. The contributions to $PM_{2.5}$ from each of the 41 upwind States to each of the downwind nonattainment counties are provided in the AQMTSD. Table V–6 provides a count of the number of downwind counties that received contributions of 0.15 $\mu g/m^3$ or more from each upwind State. This table also provides the number of downwind counties that received contributions of 0.10 $\mu g/m^3$ or more from each upwind State.

TABLE V–5.—MAXIMUM DOWNWIND $PM_{2.5}$ CONTRIBUTION ($\mu g/m^3$) FOR EACH OF 41 UPWIND STATES

Upwind state	Maximum downwind contribution	Downwind nonattainment county of maximum contribution
Alabama	1.17	Floyd, GA.
Arkansas	0.29	St. Clair, IL.
Connecticut	0.07	New York, NY.
Colorado	0.04	Madison, IL.
Delaware	0.17	Berks, PA.
Florida	0.52	Russell, AL.
Georgia	1.52	Russell, AL.
Illinois	1.50	St. Louis, MO.
Indiana	1.06	Hamilton, OH.
Iowa	0.43	Madison, IL.
Kansas	0.15	Madison, IL.
Kentucky	1.10	Clark, IN.
Louisiana	0.25	Jefferson, AL.
Maryland/District of Columbia	0.85	York, PA.
Maine	0.03	New Haven, CT.
Massachusetts	0.21	New Haven, CT.
Michigan	0.88	Cuyahoga, OH.
Minnesota	0.39	Cook, IL.
Mississippi	0.30	Jefferson, AL.
Missouri	0.89	Madison, IL.
Montana	0.03	Cook, IL.
Nebraska	0.08	Madison, IL.
New Hampshire	0.06	New Haven, CT.
New Jersey	0.45	New York, NY.
New Mexico	0.03	Knox, TN.
New York	0.85	New Haven, CT.
North Carolina	0.41	Sullivan, TN.
North Dakota	0.12	Cook, IL.
Ohio	1.90	Hancock, WV.
Oklahoma	0.14	Madison, IL.
Pennsylvania	1.17	New Castle, DE.
Rhode Island	0.01	New Haven, CT.
South Carolina	0.72	Richmond, GA.
South Dakota	0.04	Madison, IL.
Tennessee	0.57	Floyd, GA.
Texas	0.37	St. Clair, IL.
Vermont	0.06	New Haven, CT.
Virginia	0.67	Washington, DC.
West Virginia	0.89	Allegheny, PA.

TABLE V–5.—MAXIMUM DOWNWIND $PM_{2.5}$ CONTRIBUTION (μg/m³) FOR EACH OF 41 UPWIND STATES—Continued

Upwind state	Maximum downwind contribution	Downwind nonattainment county of maximum contribution
Wisconsin	1.00	Cook, IL.
Wyoming	0.05	Madison, IL.

TABLE V–6.—NUMBER OF DOWNWIND $PM_{2.5}$ NONATTAINMENT COUNTIES THAT RECEIVE CONTRIBUTIONS 0.15 μg/m³ OR MORE AND 0.10 μg/m³ OR MORE FROM EACH UPWIND STATE

Upwind state	Number of downwind nonattainment counties with contributions of 0.10 μg/m³ or more	Number of downwind nonattainment counties with contributions of 0.15 μg/m³ or more
Alabama	43	32
Arkansas	27	4
Delaware	4	1
Florida	23	19
Georgia	38	27
Illinois	53	53
Indiana	54	53
Iowa	30	13
Kansas	4	2
Kentucky	52	50
Louisiana	33	25
Maryland/District of Columbia	9	7
Massachusetts	2	1
Michigan	55	39
Minnesota	18	8
Mississippi	28	18
Missouri	47	31
New Jersey	8	7
New York	16	12
North Carolina	35	28
North Dakota	4	0
Ohio	47	47
Oklahoma	3	0
Pennsylvania	52	46
South Carolina	23	19
Tennessee	50	43
Texas	48	36
Virginia	35	17
West Virginia	46	32
Wisconsin	48	29

VI. Emissions Control Requirements

This section describes the proposed criteria EPA used to establish these new SO_2 and NO_X control requirements, for the States with emissions sources contributing to nonattainment as described in section V. This section also explains how information on EGUs was used in proposing emissions control requirements for SO_2 and NO_X to address interstate pollution transport, and what source categories were also considered by the Agency. This includes consideration of the technologies available for reducing SO_2 and NO_X emissions and the methods that we used to evaluate the cost effectiveness of these emissions reductions. This section also discusses interactions of today's proposed action with the existing Acid Rain Program under title IV of the CAA. This section discusses the emission source categories that EPA considered for today's action, and explains that we assumed control on EGUs in developing this proposal. This section also describes the methodology used for developing State budgets from the proposed control requirements, with a step in the methodology based on regionwide targets. Further, this section presents the proposed State budgets for NO_X and SO_2 for EGUs. (More details regarding requirements related to budget demonstrations can be found in section VII.) This section also discusses baseline inventories.

A. Source Categories Used for Budget Determinations

Today's action proposes requirements based on emissions reductions for EGUs. The EPA is examining potential pollution control approaches and the cost effectiveness of emissions reductions for other source categories. Today, EPA solicits comments on those other source categories, but is not proposing action on them.

1. Electric Generation Units

In developing today's proposal, we investigated various source categories to see which may be candidates for additional controls. Our attention focused on emission reductions from EGUs for several reasons. Electric Generating Units are the most significant source of SO_2 emissions and a very substantial source of NO_X in the affected region. For example, EGU emissions are projected to represent approximately one-quarter (23 percent) of the total NO_X emissions in 2010 and over two-thirds (67 percent) of the total SO_2 emissions in 2010 in the 28-State plus DC region that is being controlled for both SO_2 and NO_X after application of current CAA controls. Furthermore, control technologies available for reducing NO_X and SO_2 from EGUs are considered highly cost effective and able to achieve significant emissions reductions.

The methodology for setting SO_2 and NO_X budgets described below under sections VI.B, VI.C, and VI.D applies to EGUs only. Electric Generating Units are defined as fossil-fuel fired boilers and turbines serving an electric generator with a nameplate capacity of greater than 25 megawatts (MW) producing electricity for sale. Fossil fuel is defined as natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material. The term "fossil fuel-fired" with regard to a unit means combusting fossil fuel, alone or in combination with any amount of other fuel or material. These definitions are the same as those used under the title IV Acid Rain program.

2. Treatment of Cogenerators

The EPA is proposing that the determination of whether a boiler or turbine that is used for cogeneration should be considered an EGU is dependent upon the amount of electricity that the unit sells.[80]

We propose to treat a cogeneration unit as an EGU in this proposed rule if it serves a generator with a nameplate capacity of greater than 25 MW and supplies more than one-third of its potential electric output capacity and sells more than 25 MW electrical output to any utility power distribution system for sale in any of the years 1999 through 2002. If one-third or less of the potential electric output capacity or 25 MW or less is sold during all of those years, the cogeneration unit would be classified as a non-EGU. The definition of potential electrical output capacity proposed for this rule is the definition under part 72, appendix D of the Acid Rain regulations.

The definition of a cogeneration facility under the title IV Acid Rain program and the NO_X SIP Call was based on the Federal Energy Regulatory Commission Qualifying Facility definition. We propose to use this same definition with one change. We propose to apply the efficiency standards under title 18, section 292.205 to coal, oil, and gas-fired units instead of applying the efficiency standards only to oil and gas-fired units. The EPA believes this change would be more consistent with its fuel-neutral approach throughout this proposed rule. In addition, not applying an efficiency standard to coal-fired units would be counter productive to EPA's efforts to reduce SO_2 and NO_X emissions under this proposed rule because of the relatively high SO_2 and NO_X emissions from coal-fired units.

We solicit comment on use of this definition of cogeneration facility for purposes of developing emission budgets.

3. Non-EGU Boilers and Turbines

For several reasons, the approach we are proposing today would not require or assume additional emissions reductions from non-EGU boilers and turbines. First, compared to the information we have about emissions from EGUs and the costs of controlling those emissions, we have relatively little information about non-EGU boilers and turbines.[81] In particular, we have limited information both about SO_2 controls and the integration of NO_X and SO_2 controls. As a result, we are not able to determine that further emissions reductions from these sources would be highly cost effective. Second, based on the information we do have, projected emissions of NO_X and SO_2 from these sources in 2010 are much lower than those projected from EGUs. However, we invite information and comment on these source categories. In particular, we request comments on sources of emissions and cost information.

We recognize, for example, that some industrial boiler owners may prefer the certainty and flexibility of being included in a regional trading program, rather than facing the uncertainty of the SIP development process. In addition, many non-EGU boilers and turbines already are regulated under the NO_X SIP Call and thus are part of a NO_X trading program with EGUs. It is EPA's intent that, for EGUs, compliance with the more stringent annual NO_X reduction requirement in today's proposed rule will be able to serve as compliance with the seasonal NO_X SIP Call limits. Therefore since EGUs will no longer be participating in the seasonal NO_X SIP Call Trading Program, the cost of compliance for non-EGUs will likely increase.

4. Other Non-EGUs

We also evaluated the available information on SO_2 and NO_X emissions and control measures for source categories other than EGUs and large industrial boilers and turbines, in order to identify highly cost effective emission reductions. Our approach to considering these source categories is discussed in a technical support document available in the docket, entitled "Identification and Discussion of Sources of Regional Point Source NO_X and SO_2 Emissions Other Than EGUs (January 2004)". Based on this evaluation, we are not proposing to consider reductions from any of these source categories because we are unable to identify specific quantities of SO_2 or NO_X emissions reductions that would be highly cost effective. However, we invite information and comment on these sources categories. In particular, we request comment on sources of emissions and cost information.

The EPA did not identify highly cost-effective controls on mobile or area sources that would achieve broad-scale regional emissions reductions relative to baseline conditions and fit well with the regulatory authority available under section 110(a)(2)(D). We observe that Federal requirements for new on-road and off-road engines and motor vehicles will substantially reduce emissions as the inventory of vehicles and engines turns over.

B. Overview of Control Requirements and EGU Budgets

This section explains how EPA developed State emissions reduction requirements for NO_X and SO_2 emissions that will lead to reductions of emissions associated with the interstate transport of fine particles and ozone. We seek to implement the section 110(a)(2)(D) requirement that upwind States act as "good neighbors" by eliminating the amount of their emissions that contribute significantly to the downwind nonattainment areas. The proposed requirements would apply to 29 Eastern States (and DC) that significantly contribute to fine particle and/or ozone nonattainment.

We propose to establish these emissions reduction requirements, for both SO_2 and NO_X purposes, based on

[80] The NO_X SIP Call, as finalized in 1998, moved beyond the "utility unit" definition in the Acid Rain Program and treated as "ECUs" all fossil- fuel-fired units serving generators with a nameplate capacity exceeding 25 MW and producing any electricity for sale. This EGU definition, as applied to cogeneration units, was remanded to EPA as a result of litigation. Subsequently, EPA proposed to retain the approach in the 1998 rule, but in response to comments EPA received on that proposal, EPA is preparing to finalize a response to the court remand in which EPA will change the definition of EGU originally finalized in the NO_X SIP Call to be very similar to the existing title IV definition.

[81] *See* "Identification and Discussion of Sources of Regional Point Source NO^X and SO_2 Emissions Other Than EGUs (January 2004)".

assuming the application of highly cost-effective controls to large EGUs. The approach of identifying highly cost-effective controls was the basis for developing the emissions budgets in the NO_X SIP Call, and is the basis for developing the emissions budgets in today's action. Today's proposal bases its reduction and control requirements solely on controls for EGUs.

The States have full flexibility in choosing the sources that must reduce emissions. If the States choose to require EGUs to reduce their emissions, then the States must impose a cap on EGU emissions, which would, in effect, be an emissions budget. If a State chooses to control EGUs and elects to allow them to participate in the interstate cap and trade program, the State must follow EPA rules for allocating allowances to the individual EGUs. If a State wants to control EGUs but does not want to allow EGUs to participate in the interstate cap and trade program, the State has flexibility in allocating, but it must cap EGUs. The State must also assure that EGUs meet title IV requirements.

In 2010, the proposed requirements would effectively establish emissions caps for SO_2 and NO_X of 3.9 million tons and 1.6 million tons, respectively. The budgets would be lowered in 2015 to provide SO_2 and NO_X emissions caps of 2.7 million tons and 1.3 million tons, respectively, in the proposed control region. An SO_2 emissions cap of 2.7 million tons in 28 States will lead to nationwide emissions of approximately 3.5 million tons when the cap is fully implemented. This is significantly lower than the 8.95 million tons of SO_2 emissions allowed from EGUs under the current title IV Acid Rain SO_2 Trading Program. EPA expects that States will elect to join a regional cap and trade program for these pollutants that the Agency will administer similar to the NO_X SIP Call. This is discussed in section VIII of this proposal.

If the States choose to control other sources, then they must employ methods to assure that those other sources implement controls that will yield the appropriate amount of reductions. This is discussed further in section VII, below.

The EPA believes that it will take substantial time (more than 3 years from completion of SIPs) to install all of the equipment necessary to meet the proposed control requirements. Thus, EPA is proposing that the required reductions be made in two phases, with annual emissions caps for NO_X and SO_2 taking effect in 2010 and 2015.

Today's approach is similar to that of the NO_X SIP Call. In that case, EPA required States that controlled emissions from large boilers (either EGUs or non-EGUs) to cap emissions from those source categories. In addition, EPA allowed States to meet part of their emissions budget requirements by participating in an interstate emissions cap and trade program. The cap and trade program in effect meant that the total amount of NO_X emissions from EGUs and non-EGU boilers and turbines was limited on a regionwide basis, rather than on a State-specific basis. For other source categories, EPA did not require the State to cap emissions, as long as it demonstrated that it had enforceable measures that achieved the necessary emission reductions. We are proposing to take a similar approach in today's rulemaking.

For convenience, we use specific terminology to refer to certain concepts. "State budget" refers to the statewide emissions that may be used as an accounting technique to determine the amount of emissions reductions that controls may yield. It does not imply that there is a legally enforceable statewide cap on emissions from all SO_2 or NO_X sources. "Regionwide budget" refers to the amount of emissions, computed on a regionwide basis, which may be used to determine State-by-State requirements. It does not imply that there is a legally enforceable regionwide cap on emissions from all SO_2 or NO_X sources. "State EGU budget" refers to the legally enforceable cap on EGUs a State would apply should it decide to control EGUs.

C. Regional Control Requirements and Budgets Based on a Showing of Significant Contribution

In determining States' emissions reduction requirements, EPA considered both the level and timing of the emissions budgets for the electric power industry at a regional level and State level. The EPA wants to assist the States to attain the NAAQS for $PM_{2.5}$ and 8-hour ozone in a way that is timely, practical, and cost effective.

For purposes of the $PM_{2.5}$ and 8-hour ozone transport requirements, CAA section 110(a)(2)(D) requires that States submit SIPs than prohibit emissions in the amount that contributes significantly to nonattainment downwind. Our interpretation of the "contribute significantly" determination includes an air quality component and a cost-effectiveness component. The air quality component is discussed in sections IV, V, and IX. As to the cost-effectiveness component, in the NO_X SIP Call, we applied this component by employing "highly cost-effective" controls as the benchmark. We adopt that benchmark for today's proposal.

In determining the States' obligations under this rule, EPA considers a variety of factors. These include:

- The availability of information,
- The identification of source categories emitting relatively large amounts of the relevant emissions,
- The performance and applicability of control measures,
- The cost effectiveness of control measures, and
- Engineering and financial factors that affect the availability of control measures.

We have relatively complete information with respect to these factors for the electric power industry. We do not have information to this degree of completeness for other sources.

The electric power industry emits relatively large amounts of the relevant emissions. This factor is particularly important in a case such as this when the Federal government is proposing a multistate regional approach to reducing transported pollution.

We request comment on how to determine what constitutes "a relatively large amount" of the relevant emissions. One approach would be to consider the percent contribution the source category makes to the total inventory (*e.g.*, 1 to 10 percent). Another approach, which some have suggested, would be to consider the contribution of a source category to the total NAAQS exceedance level. For example, this approach might consider a source category's contribution to ambient concentrations above the attainment level in all nonattainment areas in affected downwind States for $PM_{2.5}$. We request comment on both of these approaches as well as what the appropriate percent contribution under each approach might be.

Under the cost effectiveness component, we also take into account available information about the applicability, performance, and reliability of different types of pollution control technologies for different types of sources. Based on engineering judgement, we consider how many sources in a particular source category can install control technology, and whether such technology is compatible with the typical configuration of sources in that category. As was done in the NO_X SIP Call, and as proposed in today's rule we also evaluate the downwind impacts of the level of control that is identified as highly cost effective. The fact that a particular control level has a substantial downwind impact affirms the selection of that level as "highly cost effective."

However, as noted above, we are requesting comment on an approach that would incorporate the effect on downwind States as part of the cost effectiveness component of significant contribution.

There are other practical considerations that we may also consider. For example, if we are aware that emissions from a particular source category will be controlled under an upcoming regulation (a MACT standard, for example), we would also take that fact into account.

We considered several additional factors, including the engineering factors concerning construction and installation of the controls when evaluating the time period needed to implement the controls. This analysis also involves consideration of the time period needed by sources to obtain the financing needed for the controls. Engineering and financial factors are discussed in this section.

The EPA's approach to controls factored in the air quality improvements that could occur. Air quality modeling that is covered in section IX indicates that today's proposed transport reductions will bring many fine particle nonattainment areas and some ozone nonattainment areas into attainment by 2010 or 2015, and improve air quality in many downwind $PM_{2.5}$ and ozone nonattainment areas. The modeling also shows more reductions will be needed for some areas to attain. We are striving in this proposal to set up a reasonable balance of regional and local controls to provide a cost effective and equitable governmental approach to attainment with the NAAQS for fine particles and ozone.

1. Performance and Applicability of Pollution Control Technologies for EGUs

In developing today's proposal, EPA focused on the utility industry as a potential source of highly cost effective reductions of both SO_2 and NO_X emissions. We began by reviewing the reliability, capability and applicability of today's SO_2 and NO_X pollution controls for this industry.

Both wet and dry flue gas desulfurization (FGD) technologies for SO_2 control, and the selective catalytic reduction (SCR) technology for NO_X control on coal-fired boilers, are fully demonstrated and available pollution control technologies. The design and performance levels for these technologies were based on proven industry experience.[82]

[82] References for this dicussion are provided in the docket for today's rulemaking.

For SO_2 control, EPA has considered two wet FGD technologies, consisting of the limestone forced oxidation system (LSFO) with dibasic acid injection and the magnesium enhanced lime (MEL) system. In addition, a dry FGD technology, lime spray dryer (LSD) system, has also been considered. Of these, the LSFO system is generally used for installations firing high-sulfur (2 percent and higher) coals, LSD for low-sulfur (less than 2 percent) coals, and MEL for both low- and high-sulfur coals, depending on the overall economics of each application.

In EPA's analyses, the SO_2 reduction capabilities considered are 95 percent for the LSFO system, 96 percent for the MEL system, and 90 percent for the LSD system. A significant amount of industry information is available on the use of these technologies. One reference shows over 30 years of operating experience in U.S. electrical utility plants. The three FGD systems considered by EPA have been used in the majority of these plants. A significant number of the wet FGD systems, especially those installed in the last 10 years, have design SO_2 removal efficiencies ranging from 95 to 99 percent. Also, there are several LSD installations designed for 90 percent or higher SO_2 removal, supporting the performance levels selected by EPA.

The EPA has also identified several other references that support its FGD technology selections. These references report long-term operating experience with wet FGD systems, with and without dibasic acids, at SO_2 removal rates of 95 to 99 percent. We also performed a study that lists in a greater detail the criteria and the references for selection of all three FGD technologies considered.

The NO_X reduction capability considered by EPA for the SCR technology is 90 percent, with the minimum NO_X emission rate limited to 0.05 lb/mmBtu. Because of this 0.05 lb/mmBtu limit, the actual NO_X reduction requirement for SCR systems on the boilers with existing or future combustion controls is expected to be less than 90 percent. For example, the baseline NO_X emissions on a large number of boilers with existing combustion controls are below 0.3 lb/mmBtu, requiring SCRs with NO_X removal rates of approximately 83 percent or lower.

The first SCR application in the U.S. on a coal-fired boiler started operating in 1993. At the end of 2002, the number of operating SCR installations on U.S. boilers stood at 56. Another 85 SCR units are scheduled to go into operation in 2003. The design NO_X reduction efficiencies of these SCR systems vary, but many of them are designed for 90 percent reduction. Operating data available from many plants indicate that the 90 percent NO_X removal rate has been met or exceeded at these plants.

There is more long-term experience with coal-fired SCR applications in Europe and Japan. This experience includes high- and medium-sulfur coal applications and is directly applicable to the U.S. installations. The overall SCR experience both in the U.S. and abroad, therefore, supports the criteria EPA has used for this technology.

SCRs and scrubbers have been used in combination on most new coal-fired powered plants built in the U.S. since the early 1990s. The combination has also been retrofit on a number of existing coal-fired units.

2. Evaluation of Cost Effectiveness

With effective, well-established controls available for both SO_2 and NO_X emissions from EGUs, EPA must determine what is the appropriate level of costs for these controls. In the NO_X SIP Call rule, EPA defined the cost component of the "contribute significantly" test in terms of a level of cost effectiveness, that is, dollars spent per ton of emissions reductions. Specifically, in the NO_X SIP Call, EPA defined the cost component in terms of "highly cost-effective" controls, a definition upheld by the D.C. Circuit in the Michigan case. Today, EPA proposes to use this approach.

We want to provide an emissions reductions program for SO_2 and NO_X that complements State efforts to attain the $PM_{2.5}$ and ozone standards in the most cost-effective, equitable and practical manner possible. The objective of the analysis is to select from the spectrum of possible pollution controls the least expensive approaches available at the time the controls are selected.

To ensure that EPA's overarching goal of achieving the NAAQS in the most cost effective, equitable and practical manner possible is met by Federal and State actions, the Agency has decided to pursue emissions reductions that it considers are highly cost effective now before State plans for nonattainment are due. Proposing highly cost-effective controls also provides greater certainty that transport controls are not being overemphasized relative to local controls.

For today's proposal, EPA independently evaluated the cost effectiveness of strategies to reduce SO_2 and NO_X to address $PM_{2.5}$ and ozone nonattainment. The results of EPA's analysis are summarized below. (All costs in this summary are rounded to the nearest hundred dollars, and are presented in 1999$.) It should be noted that the results of these analyses for SO_2 controls are not relevant to NO_X controls, and vice versa. Each pollutant has a different history of cost of controls, which makes cross-pollutant comparison inappropriate.

We note that comparisons of the cost per ton of pollutant reduced from various control measures should be viewed carefully. Cost per ton of pollutant reduction is a convenient way to measure cost effectiveness, but it does not take into account the fact that any given ton of pollutant reduction may have different impacts on ambient concentration and human exposure, depending on factors such as the relative locations of the emissions sources and receptor areas. Thus, for example, an alternative approach might adopt the effect of emission reductions on ambient concentrations in downwind nonattainment areas as the measure of effectiveness of further control. The EPA solicits comment on whether to take such considerations into account and what, if any, scientifically defensible methods may be available to do so.

a. Cost Effectiveness of SO_2 Emission Reductions

The EPA developed criteria for highly cost-effective amounts through: (1) Comparison to the average cost effectiveness of other regulatory actions and (2) comparison to the marginal cost effectiveness of other regulatory actions. These ranges indicate cost-effective controls. EPA believes that controls with costs towards the low end of the range may be considered to be highly cost effective because they are self-evidently more cost effective than most other controls in the range. Moreover, this level of cost is consistent with SO_2 and NO_X emissions reductions that yield substantial ambient benefits in downwind nonattainment areas, as discussed in section IX. For these reasons, EPA proposes today the costs identified below as highly cost-effective levels, and the associated set of SO_2 and NO_X emissions reductions and emissions budgets, as the basis for the SIP requirements.

Table VI–1 provides the average and marginal costs of annual SO_2 reductions under EPA proposed controls for 2010 and 2015. Also, EPA considered the sensitivity of the marginal cost results to assumptions of higher electric growth and future natural gas prices than it used in its base case. These assumptions in the sensitivity analysis were based on the Energy Information Agency's *Annual Energy Outlook for 2003*.

Table VI–2 provides the average cost per ton of recent EPA, State, and local Best Available Control Technology (BACT) permitting decisions for SO_2. These decisions reflect the application of BACT for SO_2 to new sources and major modifications at existing sources. These decisions, which include consideration of average and incremental cost effectiveness, reflect the application of best available controls in attainment and unclassified areas. These decisions do not reflect the application of lowest achievable emission rate, which is required in nonattainment areas and which does not directly consider cost in any form. The BACT decisions are relevant for present purposes because they comprise cost effective controls that have been demonstrated.

Table VI–3 provides the marginal cost per ton of recent State decisions for annual SO_2 controls where marginal cost information was available. These include the WRAP Regional SO_2 Trading Program and statewide rules that have required significant reductions of SO_2 in North Carolina and Wisconsin.

The results of the sensitivity analysis of the marginal cost in Table VI–1 when compared to Table VI–3 results further supports that the SO_2 controls are highly cost effective.

Additionally, the Agency further considered the cost effectiveness of alternative stringency levels for this regulatory proposal (examining changes in the marginal cost curve at varying levels of emissions reductions). Figure VI–1 shows that the "knee" in the marginal cost effectiveness curve—the point where the cost of control is increasing at a higher rate than the amount of SO_2 removal for EGUs—appears to start above $1,200 per ton. The selected approach was well below the point at which there would be significant diminishing returns on the dollars spent for pollution control. The EPA used the Technology Retrofitting Updating Model (TRUM), a spreadsheet model based on the Integrated Planning Model (IPM), for this analysis. Details of this analysis can be found in "An Analysis of the Marginal Cost of SO_2 and NO_X Reductions" (January 2004) in the docket for today's rulemaking.

TABLE VI–1.—PREDICTED COSTS PER TON OF SO_2 CONTROLLED UNDER PROPOSED CONTROL STRATEGY (1999$)/TON [1]

	2010	2015
Average Cost	$700	$800
Marginal Cost ...	700	1,000
Sensitivity Analysis: Marginal Cost, Assuming High Electric Demand and Natural Gas Price	900	1,100

[1] EPA IPM modeling; available in the docket.

TABLE VI–2.—AVERAGE COSTS PER TON OF ANNUAL SO_2 CONTROLS

SO_2 control action	Average cost (1999$)/ton
Best Available Control Technology (BACT) determinations.	$500–$2,100 [1]

[1] These numbers reflect a range of cost effectiveness data entered into EPA's RACT/BACT/LAER Clearinghouse (RBLC) for add-on SO_2 controls.

TABLE VI–3.—MARGINAL COSTS PER TON OF ANNUAL SO_2 CONTROL ACTIONS

SO_2 control action	Marginal cost (1999$)/ton
Wisconsin Multi-pollutant rule.	$1,400 [1]
North Carolina Multi-pollutant rule.	$800 [2]
WRAP Regional SO_2 Trading Program.	$1,100–$2,200 [3]

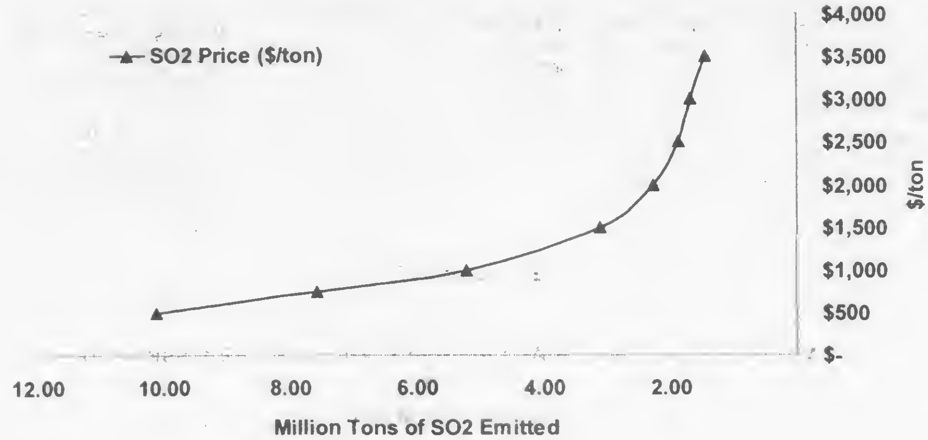
[1] EPA's IPM Base Case run, available in the docket.

[2] EPA's IPM Base Case run, available in the docket.

[3] "An Assessment of Critical Mass for the Regional SO_2 Trading Program," Prepared for Western Regional Air Partnership Market Trading Forum by ICF Consulting Group, September 27, 2002, available in the docket and at *http://www.wrapair.org/forums/mtf/critical_mass.html*. This analysis looked at the implications of one or more States choosing to opt-out of the WRAP regional SO_2 trading program.

Figure VI-1

Marginal Cost Curve of Abatement for SO2 Emissions in 2015 (NOx cap at 2.3 million tons)



b. Cost Effectiveness of NO_X Emission Reductions

In developing the NO_X SIP Call, EPA determined that an average cost effectiveness of $2,500/ton (in 1999$, from original $2,000/ton in 1990$), or less, was highly cost effective for NO_X reductions during the ozone season. This was based on review of other relevant actions EPA and others had recently taken. An updated summary of average costs of NO_X control actions is in Table VI–4. Each of the programs in Table VI–4 cover annual NO_X reductions, which makes comparison of these estimates to ozone season reductions a conservative comparison, as was done in the NO_X SIP Call. The table's results are very similar to what EPA found in 1998 and reaffirm the Agency's earlier determination of what a highly cost-effective reduction of NO_X emissions is.

Table VI–5 provides the results of EPA's analysis of the cost effectiveness of the proposed NO_X control requirements for States contributing to downwind ozone nonattainment. The average costs are well below $2,500/ton. The marginal costs in 2010 are much lower than the benchmark, but in 2015 are above it by a modest amount. Notably, if the controls during the ozone season are then used for the remaining months of the year, their costs are very low. Table VI–6 provides these results. These reductions are among the lowest cost EPA has ever observed in NO_X control actions and are obviously highly cost effective.

Table VI–7 shows the average and marginal costs of year-round controls for EPA's proposed approach. When these costs are compared to the costs in Table VI–8, it is clear that in the States that control NO_X for $PM_{2.5}$ only, the controls are highly cost effective.

The Agency further considered the cost effectiveness of alternative stringency levels for this regulatory proposal (examining changes in the marginal cost curve at varying levels of emission reductions). Figure VI–2 shows that the knee in the marginal cost effectiveness curve for NO_X appears to start above $2,000 per ton. The selected approach was well below the point at which there would be significant diminishing returns on the dollars spent for pollution control.

TABLE VI–4.—AVERAGE COST PER TON OF EXISTING AND PROPOSED ANNUAL NO_X RULES

NO_X rule [1]	Average cost (1999$)
Tier 2 Vehicle Gasoline Sulfur [2].	$1,300–$2,300
2004 Highway HD Diesel [2]	$200–$400
Off-highway Diesel Engine [2]	$400–$700
Tier 1 Vehicle Standards [2]	$2,100–$2,800
National Low Emission Vehicle [2].	$1,900
Marine SI Engines [2]	$1,200–$1,800
2007 Highway HD Diesel Stds [2].	$1,600–$2,100
On-board Diagnostics [2]	$2,300
Marine CI Engines [2]	Up to $200
Revision of NSPS for New EGUs.	$2,100

[1] Costs for rules affecting mobile sources presented here include a VOC component.
[2] Control of Air Pollution from New Motor Vehicles: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements; Final Rule (66 FR 5102; January 18, 2001). The values shown for 2007 Highway HD Diesel Stds are discounted costs.

TABLE VI–5.—PREDICTED COSTS PER TON OF OZONE SEASON-ONLY NO_X CONTROLLED UNDER PROPOSED CONTROL STRATEGY (1999$)/TON [1]

	2010	2015
Average Cost	$1,000	$1,500
Marginal Cost	2,200	2,600

[1] EPA IPM modeling; available in the docket.

TABLE VI–6.—PREDICTED COSTS PER TON OF WINTER SEASON NO_X CONTROLLED UNDER PROPOSED CONTROL STRATEGY (1999$)/TON [1]

	2010	2015
Average Cost	$700	$500

[1] EPA IPM modeling; available in the docket.

TABLE VI–7.—PREDICTED COSTS PER TON OF ANNUAL NO_X CONTROLLED UNDER PROPOSED CONTROL STRATEGY (1999$)/TON [1]

	2010	2015
Average Cost	$800	$700
Marginal Cost	1,300	1,500
Sensitivity Analysis: of Marginal Cost, Assuming High Electricity Demand and Natural Gas Price	1,300	1,600
Sensitivity Analysis: of Marginal Cost, Assuming High Electricity Demand, Natural Gas Price and SCR Costs	2,200	2,000

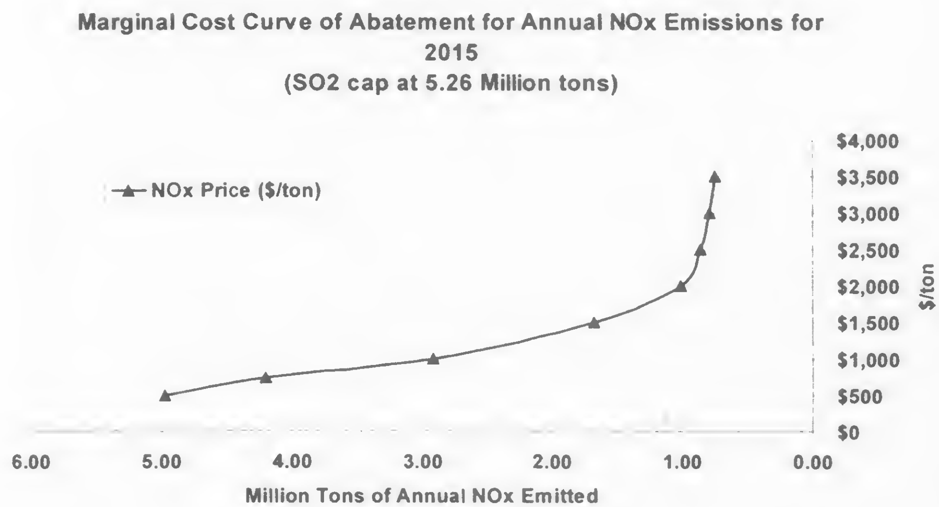
[1] EPA IPM modeling; available in the docket.

TABLE VI–8.—MARGINAL COST PER TON OF REDUCTION RECENT NO_X RULES

NO_X action	Marginal cost per ton (1999$)
Wisconsin Rules—Annual Controls.	$1,800 [1]
Texas Rules—Annual Controls.	$1,400–$3,000 [1]

[1] EPA's IPM Base Case run, available in the docket. NO_X control requirements in Texas vary regionally; the range of marginal costs here reflects the various requirements in the State.

Figure VI-2



c. EPA Cost Modeling Methodology

The EPA conducted analysis through the Integrated Planning Model (IPM) that indicates that its proposed SO_2 and NO_X control strategies are consistent with the level of controls proposed as highly cost effective. We use IPM to examine costs and, more broadly, analyze the projected impact of environmental policies on the electric power sector in the 48 contiguous States and the District of Columbia. The IPM is a multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector. It provides forecasts of least-cost capacity expansion, electricity dispatch, and emission control strategies for meeting energy demand and environmental, transmission, dispatch, and reliability constraints. We used IPM to evaluate the cost and emissions impacts of the policies to limit emissions of SO_2 and NO_X from the electric power sector that are proposed in today's rulemaking. The National Electric Energy Data System (NEEDS) contains the generation unit records used to construct model plants that represent existing and planned/committed units in EPA modeling applications of IPM. The NEEDS includes basic geographic, operating, air emissions, and other data on all the generation units that are represented by model plants in EPA's v. 2.1.6 update of IPM.

We used the IPM to conduct the cost effectiveness analysis for the emissions control program proposed in this action. The model was also used to derive the marginal cost of several State programs that EPA considers as part of its base case.

For the purpose of preliminarily evaluating today's proposal, EPA modeled a strategy that assumes SO_2 controls in the 48 contiguous States in a manner that largely leads to a cap on Eastern States without leakage of emissions to nearby States. The modeled 48-State cap simulates a control program that is very similar to the program we are now proposing to control SO_2 in only the 28-State and DC region. Most of the SO_2 emissions and reductions would occur in the 28-State and DC control region and therefore a very similar result is expected. Based on IPM modeling, the SO_2 emissions in 2015 from the proposed 28-State and DC region would be 92 percent of national emissions under base case conditions (*i.e.*, without implementation of today's proposed program). In addition, emissions reductions in the 28-State and DC region would be 96 percent of total national reductions, under the 48 State cap that was modeled. Thus, the 48-

State cap that was modeled very closely represents the proposed 28-State and DC cap.

We modeled NO_X controls in a 31 and one-half State region that includes Minnesota, Iowa, Missouri, Arkansas, Louisiana, Eastern Texas and all of the States to the east, and DC. The NO_X control region proposed in today's action (28-States and the District of Columbia, plus ozone season only control in Connecticut) is very similar to this region used for modeling.

Because the regions used for modeling SO_2 and NO_X controls encompass a significant amount of the electricity generation in the country, they provide information that could be applied to somewhat smaller or larger regions. We believe that costs (both marginal and average) in a somewhat smaller or larger region would be similar.[83]

In this modeling case, EPA assumes interstate emissions trading. While EPA is not requiring States to participate in an interstate trading program for EGUs, EPA believes it is reasonable to evaluate control costs assuming States choose to participate in such a program since the program will result in less expensive reductions.

The modeled case discussed below assumes a phased program, with the first set of reductions occurring in 2010 and the second phase occurring in 2015. For SO_2 in particular, it should be noted that the regional reductions or budget levels are not actually achieved in the year that they are implemented. This is because of the existence of an SO_2 emission bank. The availability of the SO_2 emission bank allows sources to make emission reductions earlier and then use the allowances that are saved at a later date. Banking has less of an effect on NO_X emissions because in the existing ozone-season only program, NO_X allowances are more expensive than they are expected to be in an annual program. Thus, there is not an incentive to make early NO_X emission reductions to create allowances to be used in the future.

3. Timing, Engineering and Financial Factor Impacts

While cost considerations are one of the primary components in establishing emission reduction requirements, another important consideration is the time by which the emission reductions may be achieved. The EPA has determined that for engineering and financial reasons, it would take substantial time to install the projected controls that would be necessary to reach the ultimate control levels proposed. We seek to require implementation of the reductions on a schedule that will provide air quality benefits as soon as feasible to as many nonattainment areas as possible. Therefore, we propose to require the implementation of as much of the reductions as possible by an early date and to set a later date for the remaining amount of reductions.

Specifically, EPA proposes that the first phase must be implemented by January 1, 2010. This date is based upon the following schedule: EPA finalizes today's proposed rule by mid-2005; States submit SIPs by the end of 2006; and sources install the first phase of required controls by January 1, 2010, and the second phase by January 1, 2015.

EPA recognizes that this two-phase approach assumes that States will achieve the reduction requirements imposed by the rules proposed today through controls on EGUs. Of course, States may choose to control different sources, and if so, the specific engineering constraints applicable to EGU compliance may not apply to these other sources.[84] Nevertheless, EPA believes it appropriate to authorize a two-phase approach for all States, regardless of how they choose to achieve the reduction requirements. This approach is consistent with the fact that EPA calculated the amount of reductions required on the basis of assumed controls on EGUs, as well as the fact that as a practical matter, most (if not all) States are likely to adopt EGU controls as their primary (if not exclusive) way to achieve the required reductions.

a. Engineering Assessment To Determine Phase 1 Budgets

When designing an emissions reductions program such as EPA is proposing in today's action, the Agency must consider the effect that the timing and reduction stringency of the program will have on the quantity of resources required to complete the control technology installation and the ability of markets to adjust and to provide more resources where needed. We used IPM to predict the number and size of facilities that would install new emissions control equipment to meet the implementation dates and emissions reductions in today's proposed rule. Then, we estimated the resources required for the installation of those control technologies.

Today's proposed rule does not require the imposition of controls on any particular source and instead leaves that matter to the affected States. However, the cost effectiveness of EGU controls makes it likely that many States will achieve reductions through EGU controls. Accordingly, EPA considers it appropriate to evaluate the timing of the reduction requirements with reference to the EGU control implementation schedule. Therefore, today's proposed rule assumes the installation of significant numbers of SO_2 and NO_X controls on EGUs. To meet the existing Federal title IV program and NO_X SIP Call requirements, there has been a reliance on low sulfur coal and limited use of scrubbers (also called FGD) for SO_2 reductions and low NO_X burners and post-combustion controls (*e.g.*, SCR) for NO_X reductions, as well as shifting of dispatch to more efficient and less polluting units for each air pollutant. However, to meet the future requirements proposed in today's rule, for SO_2 control we predict there will be heavy reliance on scrubbers in the decade following finalization of today's rule. For NO_X control, we predict there will be heavy reliance on SCR and, to a much lesser degree, selective non-catalytic reduction (SNCR) and gas reburn.

The installation of the advanced post-combustion controls required under today's proposal will take significant resources and time. Installation of these controls are large-scale construction projects that can span several years, especially if multiple units are being installed at a single power plant. If EPA were to allow sources all of the time they needed to install controls to meet the ultimate cap levels without the imposition of intermediate caps, the consequences for SO_2 and NO_X would be different. For SO_2, the existence of the title IV program and the ability to bank would likely encourage sources to run their SO_2 emission controls as soon as they were installed. While these early reductions would be environmentally beneficial, they would also allow sources to continue to increase their SO_2 banks. By creating an intermediate cap, the ability to bank would be limited. For NO_X, there would be little incentive to turn on controls and achieve additional reductions, particularly in the non-ozone season and in the States not affected by the NO_X SIP Call. Therefore, in order to get any additional NO_X reductions—either during the winter

[83] We began our emissions and economic analysis for today's proposal before the air quality analysis, which affects the States we are proposing for control requirements, was completed. Thus, we modeled emissions and economic effects on regions that are similar but not identical to the region proposed today. We intend to publish revised emissions and economic modeling in a supplemental action.

[84] Other sources may face similar or other timing constraints for implementation purposes.

months from already installed SCRs or year-round from newly installed SCRs outside of the SIP Call region—it is necessary to impose an intermediate cap.

We believe that 3 years is a reasonable amount of time to allow companies to install emission controls that could be used to comply with the first phase reduction requirements of today's proposed rule. In certain circumstances, some individual units could install emissions reduction equipment in considerably less time than 3 years.[85] In the report, "Engineering and Economic Factors Affecting the Installation of Control Technologies for Multi-pollutant Strategies' (October 2002), EPA projected that it would take on average about 21 months to install a SCR on one unit and about 27 months to install a scrubber on one unit. However, many times, companies must install controls on units at the same plant. To do so, companies will often stagger installations to minimize operational disruptions, thereby taking more time. We project that seven SCRs could be installed at a single facility in 3 years. Also, we project that three scrubber modules (scrubbing a total of six units) could be installed in 3 years. Since we believe that 3 years is enough time to install controls on all the units required at a large power plant, EPA believes that 3 years is a reasonable amount of time to allow for the first phase of compliance.

The availability of skilled labor—specifically, boilermakers—is an important constraint for the installation of significant amounts of emission controls. Boilermakers are skilled steel workers who are specially trained to install both NO_X controls such as SCR and SO_2 controls such as scrubbers.

Since the availability of boilermaker labor affects the installation of both SO_2 controls and NO_X controls, it is also necessary to decide what mix of pollution reductions is desired in the first phase. In today's rulemaking, EPA is proposing to require similar percentage reductions of both SO_2 and NO_X in the first phase. In developing the first phase control levels, we intended to maximize the total control installations possible (and thus total reductions) considering the constraint on boilermaker labor, while getting similar reductions for both pollutants. This results in predicted reductions of between 40 and 50 percent for both pollutants, in the first phase.

[85] For instance, a SCR was installed on a 675 MW unit in about 13 months (Engineering and Economic Factors, p.21).

Based on all of these constraints, EPA is proposing a two-phase reduction requirement, with a first phase cap on SO_2 in 2010 based on a 50 percent reduction from title IV levels. This represents about a 40 percent reduction in emissions from the Base Case. This strategy would require about 63 GW of scrubbers to be installed by 2010. Of these, 49 GW of scrubbers would be incremental to the Base Case. (We based this analysis on the assumption that States choose to control EGUs.)

The EPA's proposed NO_X reduction requirement would also be implemented in two phases, with a first phase cap based, in a comparable manner, on about a 49 percent decrease in emissions from the Base Case. (The calculation of this first phase cap is discussed more below.) This cap would require installation of about 39 GW of SCR between 2005 and 2010. Of this, 24 GW are incremental to the Base Case. (We based this analysis on the assumption that States choose to control EGUs.)

Since the NO_X SIP Call experience showed that many power companies are averse to committing money to install controls until after State rules are finalized, EPA analyzed availability of boilermakers assuming companies did not begin installing controls until after the State rules were finalized. While boilermakers are one of the key components in building SCRs and scrubbers, most of their work cannot begin until well into the construction project. First, the power company must do preliminary studies to determine which controls to install, then jobs must be bid and design must begin. After the installation is designed, foundations must be poured and pieces of the control equipment must be built in machine shops. It is only after all of this activity has taken place that the boilermakers can erect the control equipment.

We assumed, therefore, that most of the demand for boilermakers came in the last 21 months of the 3 year period to install controls. Furthermore, in order to have controls fully operational in time for the compliance deadline, companies would likely complete installation well before the deadline to allow for testing of the controls. Assuming that most companies would try to complete controls in time to provide for a 3-month testing period, most of the demand for boilermaker labor will come in an 18-month window.

It is EPA's projection that approximately 12,700 boilermaker years would be needed to install all of the required equipment for the first phase of compliance. We project that approximately 14,700 boilermaker years would be available during the time when first phase controls would be installed. This projected number of boilermakers is based on the assumption that all the boilermakers that EPA projects are available for work on power sector environmental retrofit projects would be fully utilized (*e.g.*, 40 hours a week for 50 weeks of the year). In reality, it would be difficult to achieve this full utilization of boilermakers. For instance, boilermakers will be unable to work when moving from job-site to job-site, during inclement weather, *etc.* We believe that the availability of approximately 15 percent more boilermaker years than are required assures that there are enough boilermakers available to construct all of the required retrofits.

b. Financial and Other Technical Issues Regarding Pollution Control Installation

The EPA recognizes that the power sector will need to devote large amounts of capital to meet the control requirements of the first phase. Controls installed by 2010 will generally be the largest and easiest to install. Subsequent controls will need to be installed at more plants and under more challenging circumstances. We believe that deferring the second phase to 2015 will provide enough time for companies to overcome these technical challenges and raise additional, reasonably-priced capital needed to install controls.

4. Interactions With Existing Title IV Program

As EPA developed this regulatory action, great consideration was given to interactions between the existing title IV program and today's proposed rule designed to achieve significant reductions in SO_2 emissions beyond title IV. Requiring sources to reduce emissions beyond what title IV mandates has both environmental and economic implications for the existing title IV SO_2 trading program. In the absence of a method for accounting for the statutory requirements of title IV, a new program that imposes a tighter cap on SO_2 emissions for a particular region of the country would likely result in an excess supply of title IV allowances and the potential for increased emissions in the area not subject to the more stringent emission cap. The potential for increased emissions exists in the entire country for the years prior to the proposed implementation deadline and would continue after implementation for any areas not affected by the proposed rule. These excess emissions could negatively affect air quality, disrupt allowance markets, and erode confidence in cap and trade programs.

In view of the significant reductions in SO_2 emissions under title IV of the CAA, the large investments in pollution controls that firms have made under title IV that enable companies to sell excess emissions reductions, and the potential for emissions increases, it is necessary to consider ways to preserve the environmental benefits achieved through title IV and maintain the integrity of the title IV market for SO_2 allowances. The EPA does not have authority to address this issue by tightening the requirements of title IV. In any event, title IV has successfully reduced emissions of SO_2 using the cap and trade approach, eliminating millions of tons of SO_2 from the environment. Building on this existing program to further improve air quality by requiring additional reductions of SO_2 emissions is appropriate.

We have developed an approach to incorporate the title IV SO_2 market to ensure that the desired reductions under today's action are achieved in a manner consistent with the previously stated environmental goals. Our proposed approach effectively reduces the title IV cap for SO_2 and allows title IV allowances for compliance with this rule at a ratio greater than one-to-one. Section VIII provides more detail on our initial analysis of the interactions between the title IV Acid Rain program and today's proposed cap and trade program and outlines a solution for creating a new rule that builds off of title IV.

D. Methodology for Setting SO_2 and NO_X Budgets

In section D, EPA describes in detail how it proposes to establish the reduction requirements and, to the extent applicable, budget requirements for EGUs. The first step for both SO_2 and NO_X was determining the total amount of emissions reductions that would be achievable based on the control strategy determined to be highly cost effective. Our evaluation of cost effectiveness for the proposed 2010 and 2015 emissions caps was explained in the preceding subsection as was the need to split these budget requirements into two phases to assure that emission reductions were achieved expeditiously considering factors that could limit the amount of emission controls that could be installed in a given time period.

There were then two more steps that followed. In the second step, EPA determined the amount of emissions reductions that were needed across the region covered by this proposal and, for EGUs, set annual emissions caps accordingly in 2010 and 2015. These caps remain at the 2015 levels thereafter, to maintain air quality in the downwind areas. In the third step, EPA partitioned the cap levels into State emissions budgets that they may use for granting allowances for SO_2 and NO_X emissions.

1. Approach for Setting Regionwide SO_2 and NO_X Emission Reductions Requirements

a. SO_2 Budgets for EGUs

The EPA is proposing a two-phase SO_2 reduction program. The first phase, in 2010, would reduce SO_2 emissions in the 28-State and DC region by the amount that results from making a 50 percent reduction from title IV Phase II allowance levels. The second phase, in 2015, would further reduce SO_2 emissions by the amount that results from making a 65 percent reduction from the title IV Phase II allowance level.

These amounts may be calculated in terms of regionwide EGU caps for the first and second phases, assuming that all the affected States control only EGUs. Similarly, it is necessary to calculate the amount of regionwide SO_2 reductions for the first and second phase, for States that choose to control sources other than (or in addition to) EGUs. This calculation of the amount of the regionwide cap or emissions reductions is a useful step because this amount may then be apportioned to individual State. In addition, the methodology for calculating regionwide amounts should accommodate revisions in the universe of States in the region—adding or subtracting individual States—based on refinement to the air quality modeling that EPA expects to complete and publish in the SNPR.

The EPA proposes that the regionwide SO_2 budgets may be calculated by adding together the title IV Phase II allowances for all of the States in the control region, and making a 50 percent reduction for the 2010 cap and a 65 percent reduction for the 2015 cap. This results in a first phase SO_2 cap of about 3.9 million tons and a second phase cap of about 2.7 million tons, in the 28-State and DC control region.

Modeling predicts nationwide SO_2 emissions of about 5.4 million tons in 2015 with today's proposed controls. (This compares to approximately 9.1 million tons without today's proposed controls.) Predicted emissions in the 28-State and DC region that EPA is proposing to find significantly contribute to $PM_{2.5}$ nonattainment are about 4.6 million tons in 2015. (These emission estimates are from modeling using the 48-State region as described above.) The projected SO_2 emissions are higher than the caps due to use of banked allowances resulting from the incentive for early reductions. Accordingly, the 2015 annual SO_2 emissions reductions amount to about 3.7 million tons, and the 2010 annual SO_2 emissions reductions amount to about 3.6 million tons.

b. NO_X Budgets for EGUs

The EPA is proposing a two-phased annual NO_X control program, with a first phase in 2010 and a second phase in 2015, which would apply to the same control region as the SO_2 requirements, that is, 28-States and DC. In addition, Connecticut would be required to control NO_X during the ozone season.

On a regionwide basis, the control requirements EPA is proposing would result in a total EGU NO_X budget of about 1.6 million tons in 2010 and 1.3 million tons in 2015, in the 28-State and DC region that would be affected by today's rulemaking (assuming each State controlled only EGUs and thereby subjected themselves to the proposed caps). In addition, the control requirements would lead to 2015 annual NO_X emissions reductions of about 1.8 million tons from the base case, and 2010 annual NO_X emissions reductions of about 1.5 million tons from the base case.

Calculating the regionwide budget and emissions reductions requirements serve the same purposes as in the case of SO_2, described above. Our methodology proposed today determines historical annual heat input data for Acid Rain Program units in the applicable States and multiplies by 0.15 lb/mmBtu (for 2010) and 0.125 lb/mmBtu (for 2015) to determine total annual NO_X mass. For the annual heat input values to use in this formula, EPA proposes to take the highest annual heat input for any year from 1999 through 2002 for each applicable State. This proposed approach provides a regionwide budget for 2010 that is approximately 37,500 tons more than the budget that would result from using the highest annual regional heat input for any of the 4 years, and about 60,700 tons more than using the average regional heat input for the 4-year period. We believe that this cushion provides for a reasonable adjustment to reflect that there are some non-Acid Rain units that operate in these States that will be subject to the proposed budgets.

Note that EPA proposes today that Connecticut contributes significantly to downwind ozone nonattainment, but not to fine particle nonattainment. Thus, Connecticut would not be subject to an annual NO_X control requirement, and is not included in the 28-State and DC region we are proposing for annual controls. Connecticut would be subject to an ozone season-only NO_X cap.[86] Because Connecticut is required to make reductions only during the ozone season, compliance for sources would not be required to begin until May 1, 2010. If Connecticut chooses to participate in the regional trading program on an annual basis, compliance would begin on January 1, 2010.

Although EPA proposes to determine the regionwide amount of EGU NO_X emissions by using historic heat input and emission rates of 0.15 lb/mmBtu and 0.125 lb/mmBtu, we take comment on using, instead, heat input projected to the implementation years of 2010 and 2015 and/or different emission rates. Under this approach, we take comment on whether to use the same method for projecting heat input as used in the NO_X SIP Call, or a different method. The NO_X SIP Call method is described in 67 FR 21868 (May 1, 2002).

2. State-by-State Emissions Reductions Requirements and EGU Budgets

This section describes the methodologies used for apportioning regionwide emission reduction requirements or budgets to the individual States. State budgets may be set with a methodology different from that used in setting the regionwide budgets, for reasons described in this section.

In practice, if States control EGUs and participate in the regional trading program, the choice of method used to impose State-by-State reduction requirements makes little difference in terms of total regionwide SO_2 and NO_X emissions. The cap and trade framework would encourage least-cost compliance over the region, an outcome that does not depend on the individual State budgets.

However, the distribution of budgets to the States is important in that it can have economic impacts on the State's sources. Should a State receive a disproportionate share of the regionwide budget, there would be fewer allowances to allocate to its sources. This may adversely affect compliance costs for sources within that State as they are forced to increase their level of emission control or became net buyers from sources in States that may have received a greater share of regionwide cap.

For SO_2, we propose determining State SO_2 budgets for EGUs on the basis of title IV allowances, which is in line with the planned interactions of this rule with title IV of the CAA Amendments. See section VIII for a more detailed discussion of interactions with title IV. Such budgets would be easy to understand, would be straightforward to set, would reflect previously implemented allocations and would allow for the smoothest transition to the new program proposed today.

For the proposed 28 State SO_2 control region, the proposed annual State EGU SO_2 budgets are presented in Table VI–9, below.

TABLE VI–9.—28-STATES AND DISTRICT OF COLUMBIA ANNUAL EGU SO_2 BUDGETS

State	28-State SO_2 budget 2010 (tons)	28-State SO_2 Budget 2015 (tons)
Alabama	157,629	110,340
Arkansas	48,716	34,101
Delaware	22,417	15,692
District of Columbia	708	495
Florida	253,525	177,468
Georgia	213,120	149,184
Illinois	192,728	134,909
Indiana	254,674	178,272
Iowa	64,114	44,879
Kansas	58,321	40,825
Kentucky	188,829	132,180
Louisiana	59,965	41,976
Maryland	70,718	49,502
Massachusetts	82,585	57,810
Michigan	178,658	125,061
Minnesota	50,002	35,001
Mississippi	33,773	23,641
Missouri	137,255	96,078
New Jersey	32,401	22,681
New York	135,179	94,625
North Carolina	137,383	96,168
Ohio	333,619	233,533
Pennsylvania	276,072	193,250
South Carolina	57,288	40,101
Tennessee	137,256	96,079
Texas	321,041	224,729
Virginia	63,497	44,448
West Virginia	215,945	151,162
Wisconsin	87,290	61,103
Total	3,864,708	2,705,293

[86] If Connecticut, or any State subject to an existing NO_X ozone season-only budget program, chooses to participate in the interstate NO_X trading program proposed today, that State would need to operate under an annual NO_X cap rather than ozone season only. Interstate trading is discussed in more detail in section VIII, below.

If alternatively, EPA were to adopt an 0.10 μg/m³ as the air quality criterion, Oklahoma and North Dakota would also receive SO_2 budgets. Oklahoma's 2010 State SO_2 budget would be 63,328 tons and its 2015 SO_2 budget would be 44,330 tons. North Dakota's 2010 SO_2 budget would be 82,510 tons and its 2015 SO_2 budget would be 57,757 tons.

If the State EGU SO_2 budget is entirely based on the title IV retirement ratio, then the budget would equal the title IV allowances multiplied by the retirement ratio (as discussed earlier in this section). However, under the CAA, the title IV SO_2 allowances are allocated on the basis of activity as of 1985, and as a result, they do not take into account any of the significant changes and growth in the sectors since that time.

An alternate method of determining State SO_2 EGU budgets would consist of two parts:

(1) The first part of the budget would be based on title IV allocations—but with a tighter title IV retirement ratio than that proposed for the region.

(2) The tighter retirement ratio would result in some un-allocated EGU allowances (reflecting the difference between the regionwide budget and State budgets calculated based on part (1)). These could be allocated to States' budgets for their non-title IV EGUs, or as a way to redistribute or update allowances to the title IV EGUs. This allocation could be done on the basis of methods discussed in more detail below. Such a two-part EGU budget would recognize the fact that the sector has grown and changed since title IV allocations were initially made.

For NO_X, we propose determining State NO_X budgets for EGUs on the basis of current/historic heat input rates. Regionwide budgets would be distributed to States based on an average of several years of historical data. We are proposing to use data from 1999 to 2002.

A similar approach was taken by the SO_2 program under title IV of the CAA. As a result, States with significant projected increases in growth were required to either: (1) Reduce their emissions further, or (2) burn fuel more efficiently in order to compensate. (For such States, the ability to trade emissions regionwide was particularly attractive because States with low increases or decreases in utilization could trade emissions with States having significantly increased utilization).

Most of the States within the proposed control region are part of the NO_X SIP Call, with a regionwide budget that on a seasonal basis constrains increases in NO_X emissions for the region as a whole. States with high growth (measured from a historic baseline to the start of the new program) would already be provided incentives to control NO_X emissions as they would need to use additional NO_X SIP Call allowances to emit during the ozone season. Consequently, growth in generation in the years after the proposed State budgets have been set would not necessarily lead to increased emissions. Furthermore, the majority of the growth (of heat input, or output) through 2010 is expected to be met by recently built natural gas units, with no SO_2 and very low NO_X emissions.

Such an option is also appropriate to consider if it is decided that SO_2 budgets for non-title IV sources should be developed as explained below.

Among the advantages of a budget methodology based on historic/current activity is that it is relatively simple to implement and would not need to be changed as a result of future data.

For the proposed 28 State Annual NO_X control region, the proposed annual State EGU NO_X budgets based on this methodology are presented in Table VI–10, below.

TABLE VI–10.—28-STATES AND DISTRICT OF COLUMBIA ANNUAL EGU NO_X BUDGETS

State	28-State NO_X Budget 2010 (tons)	28-State NO_X Budget 2015 (tons)
Alabama	67,414	56,178
Arkansas	24,916	20,763
Delaware	5,039	4,199
District of Columbia	215	179
Florida	115,489	96,241
Georgia	63,567	52,973
Illinois	73,613	61,344
Indiana	102,283	85,235
Iowa	30,454	25,378
Kansas	32,433	27,027
Kentucky	77,929	64,940
Louisiana	47,333	39,444
Maryland	26,604	22,170
Massachusetts	19,624	16,353
Michigan	60,199	50,165
Minnesota	29,300	24,417
Mississippi	21,930	18,275
Missouri	56,564	47,137
New Jersey	9,893	8,245
New York	52,448	43,707
North Carolina	55,756	46,463
Ohio	101,692	84,743
Pennsylvania	84,542	70,452
South Carolina	30,892	25,743
Tennessee	47,734	39,778
Texas	224,181	186,818
Virginia	31,083	25,903
West Virginia	68,227	56,856
Wisconsin	39,039	32,533
Total	1,600,392	1,333,660

If alternatively, EPA were to adopt an 0.10 μg/m^3 as the air quality criterion, Oklahoma and North Dakota would also receive annual NO_X budgets. The proposed annual State EGU NO_X budgets for all 30 States based on the proposed methodology are presented in Table VI–11 below.

TABLE VI–11.—30-STATE AND DISTRICT OF COLUMBIA ANNUAL EGU NO_X BUDGETS

State	30-State NO_X budget 2010 (tons)	30-State NO_X budget 2015 (tons)
Alabama	67,415	56,179
Arkansas	24,916	20,763
Delaware	5,039	4,199
District of Columbia	215	179
Florida	115,490	96,242
Georgia	63,568	52,973
Illinois	73,614	61,345
Indiana	102,283	85,236
Iowa	30,454	25,378
Kansas	32,433	27,027
Kentucky	77,929	64,941
Louisiana	47,333	39,445
Maryland	26,604	22,170
Massachusetts	19,624	16,353
Michigan	60,199	50,166
Minnesota	29,300	24,417
Mississippi	21,930	18,275
Missouri	56,565	47,137
New Jersey	9,894	8,245
New York	52,448	43,707
North Carolina	55,756	46,463
North Dakota	26,570	22,141
Ohio	101,693	84,744
Oklahoma	41,293	34,411
Pennsylvania	84,543	70,452
South Carolina	30,892	25,744
Tennessee	47,734	39,778
Texas	224,183	186,819
Virginia	31,083	25,903
West Virginia	68,227	56,856
Wisconsin	39,040	32,533
Total	1,668,268	1,390,223

There are two different metrics that EPA could use for determining alternate State EGU NO_X budgets. These metrics include:

(1) Pro-rated emissions levels (budgets based on reductions in emissions levels),

(2) Pro-rated share of Output (kwh) (budgets based on their output (same lb/kwh rate)).

We solicit comment on the use of these different methods.

There are options for implementing the heat input-based budget and the two different metrics in determining actual State budgets. Budgets could be based on projected levels (calculated by taking historical level and applying growth rates, or directly taking levels projected by IPM).

The methodology used in the NO_X SIP Call (setting State budgets by applying State-specific growth rates for heat input) is an example of this approach. (67 FR 21868; May 1, 2002) Alternatively, it would be possible to use heat input or output as projected directly by IPM in the setting of budgets. This would have the benefit of being consistent with the methodology for determining cost. We would also have projections for relevant years, and there would be little disconnect between the years used to develop growth rates and the years to which growth rates are applied. However, under such a methodology, it would be difficult to adjust budgets if we receive comments about missing units. We solicit comment on these options.

As noted above, EPA proposes that Connecticut contributes significantly to ozone nonattainment areas, but not to fine particle nonattainment areas. Thus, Connecticut would not be subject to proposed annual SO_2 and NO_X controls, but would be subject to ozone season-only NO_X control requirements. We propose an ozone-season EGU NO_X control level of 4,360 tons in 2010 and about 3,633 tons in 2015.

If Connecticut (or any State subject to an existing NO_X ozone season-only budget program) chooses to participate in the interstate trading program proposed today, that State would need to operate under an annual NO_X cap rather than ozone season only. Interstate trading is discussed in more detail in section VIII of this preamble. The EPA proposes an annual NO_X control level of about 9,283 tons in 2010 and 7,735 tons in 2015, if Connecticut were to participate in today's proposed interstate trading program on an annual basis.

The EPA calculated these proposed levels using the 1999 Acid Rain Program reported heat inputs for Connecticut. The ozone-season level was calculated by multiplying the reported ozone-season heat inputs by 0.15 lb/mmBtu for 2010 and 0.125 lb/mmBtu for 2015. The proposed annual level was determined by multiplying the reported annual heat input by 0.15 lb/mmBtu for 2010 and 0.125 lb/mmBtu for 2015. We reviewed reported Acid Rain Program heat inputs for the years 1999 through 2002, and selected 1999 data for calculating these proposed levels because the 1999

Connecticut heat input was higher than the other 3 years considered, and this is similar to the way the regionwide proposed control levels were calculated.

The EPA also takes comment on an alternate way to calculate a NO_X budget for Connecticut that would be entirely consistent with the way that the budgets were calculated for other States. Under this methodology, EPA would calculate region wide NO_X budgets for both the ozone season and non ozone season using State by State heat input data for the highest year between 1999 and 2002 and multiplying it by 0.15 lbs/mmBtu for 2010 and 0.125 lbs/mmBtu for 2015. Both ozone season and non-ozone season State budgets would be calculated by giving States their pro-rated share of the budget based on annual heat input from the years 1999 to 2002. For States required to make year-round reductions, their budgets would be based on the sum of their ozone-season and non-ozone season heat input. For a State such as Connecticut that was only required to make ozone-season reductions, its ozone-season budget would be based upon its share of the ozone-season budget. If Connecticut decided to participate on an annual basis, its budget would be calculated like all other States.

E. Budgets for Use by States Choosing To Control Non-EGU Source Categories

While EPA is not proposing to assume any emissions reductions from other source categories (*e.g.*, non-EGU stationary sources, area sources and mobile sources), States may elect to obtain some or all of the required emissions reductions from other source categories. In this case, EGUs within the State would not be able to participate in the cap and trade programs.

If a State chooses to obtain some but not all of its required reductions from EGUs, it would set an EGU SO_2 budget and/or an EGU NO_X budget, at some level higher than shown in Tables VI–9 and VI–10. The State must also (1) develop baseline emissions sub-inventories for all non-EGU sectors for 2010 and 2015, (2) divide the portion of the required emissions reductions that it will not obtain from EGUs (*i.e.*, the difference between its selected EGU budget for SO_2 or NO_X and the budget listed in Tables VI–9 or VI–10) among the non-EGU source sectors in any manner it chooses, (3) subtract these emissions reductions from the corresponding emissions sub-inventories to arrive at the emissions budget for each sector, and (4) adopt measures that are projected to achieve those budgets. Compliance with all of these control measures would be enforceable. Section VII explains the role of emission budgets for non-EGU sectors in more detail. We plan to propose in the SNPR requirements to ensure the accuracy of the baseline emission sub-inventories.

We believe it is unlikely that any State will choose to obtain all or part of the required SO_2 and NO_X emission reductions from sources other than EGUs, but we do wish to offer States this alternative if equal reductions can be obtained. The SNPR will propose specific emission reductions for this purpose, or provisions for determining these emission reduction quantities. Once these are determined, the four steps described in the previous paragraph will apply.

F. Timing and Process for Setting Baseline Inventories and Sub-Inventories

In the NO_X SIP Call, EPA promulgated a NO_X emission reduction requirement for each State (as we propose here for SO_2 and NO_X). We also promulgated baseline sub-inventories for each State for five sectors (EGU, non-EGU, area, non-road, and highway) which summed to an overall baseline inventory. Finally, the NO_X SIP Call rule contained a table of State-by-State NO_X emissions budgets, developed by subtracting the required NO_X emission reduction from the overall baseline NO_X inventory.

Today, we are proposing specific EGU budgets for affected States for the purposes of the model trading program, but we are not proposing any baseline sub-inventories. There is no need for baseline sub-inventories to be established by rule for States choosing to participate in the model trading programs. As explained in section VI.E above, we propose that if a State chooses to obtain some of the required emission reductions from non-EGU sources, the baseline sub-inventories and the sector budgets should be developed by the State itself and be subject to EPA approval as part of the transport SIP. In this way, baseline sub-inventories and sector budgets will reflect updates to newer emission estimation methods, more recent data on current emissions, and updated projection methods. This will increase the certainty that the required emission reductions will be achieved in practice.

We invite comment at this time on what assumptions and methods for establishing sector inventories should be specified in the supplemental proposal and final rule. In the NO_X SIP Call, for example, we said that emissions reductions from subsequent Federal rules must be incorporated into the baseline sector inventories. Clear rules regarding determination of historical emissions, development of growth factors, estimation of rule effectiveness, and credibility of State-adopted measures may also be needed.

Section IV, above, presents the baseline emission projections that have been used in the air quality modeling that supports today's proposal. We will be updating these baseline inventories for the final rule to incorporate newer data and methods.

G. Comment on Emissions Caps and Budget Program

While EPA's analysis indicates that the availability of boilermaker labor will be a limiting factor in first phase scrubber installations, the Agency is soliciting comment on this analysis. In particular, we're asking for comment on whether there might be alternative post-combustion technologies that could reduce SO_2 emissions in a manner equally cost-effective as scrubbers, but that wouldn't require as much boilermaker labor. Examples might include multi-pollutant technologies (boilermaker labor might be less constrained if single technologies can be installed to reduce both SO_2 and NO_X). We also solicit comment on whether advanced coal preparation processes might provide highly cost effective emission reductions. We solicit comment on whether such alternative technologies will be commercialized by 2010, and what the costs will be.

In addition, EPA seeks comment on whether other factors such as other EPA regulatory actions will create an increase in boilermaker demand earlier than today's proposal (pre-2007), resulting in growth in the number of boilermakers that could be used to install controls required under this program in 2007 and beyond. We solicit comments on whether other factors might increase demand for boilermakers in advance of 2007, and what these factors would be.

As noted above, EPA is proposing to require SO_2 and NO_X to be reduced by similar percentages in the first phase of today's proposed rule, given the limited supply of labor to install controls at electric generating units. An alternative would be to give priority to SO_2 control in the first phase, and postpone summertime NO_X reductions for a couple of years. This would focus limited labor resources on SO_2 control to reduce the sulfate component of $PM_{2.5}$ as quickly as possible. This approach could achieve more early $PM_{2.5}$ reductions and might help some $PM_{2.5}$ nonattainment areas attain earlier. On the one hand, based on the analysis of section XI, the quantified benefits from $PM_{2.5}$ control are generally larger than those for ozone. Nevertheless, the tradeoff would be that ozone reductions under the interstate air quality rule would be postponed. Because many ozone areas will be required to attain in 2010, fewer projected ozone nonattainment areas would be helped by the interstate air quality rule. A number of areas required to attain in 2010 (and perhaps some 2013 areas as well) would incur greater local control costs to attain on time, or achieve less improvement in ozone levels. We request comment on the relative merits of the proposed approach and this alternative, considering public health, costs, and equity. More generally, EPA seeks comment on the mix of first phase SO_2 and NO_X reductions that represents the proper balance between the goals of reducing $PM_{2.5}$ transport and ozone transport in the near term.

Additionally, EPA seeks comment on the level of the second phase caps and the resulting division of responsibility between local and interstate transport sources. Would a less stringent or more stringent level of transport control lower total costs of attainment, or better address equity issues? Has EPA identified the appropriate level of control as highly cost effective? Should the Agency reduce the second-phase reductions (or raise the second-phase caps) for NO_X and SO_2, and thereby leave more of the emissions reductions burden to the individual States preparing plans for meeting air quality standards in each nonattainment area? Or should the second-phase emissions reductions be increased (or the caps be made lower) in an effort to give more help to States through regional controls that achieve greater reductions and benefits while remaining cost effective? For example, rather than basing the 2015 caps on a 65 percent reduction from title IV levels, should they be based on a 55 percent reduction or a 75 percent reduction?

The EPA also requests comment on the timing of each phase of the cap and trade program. Regarding the first phase, EPA notes that the January 1, 2010 NO_X compliance date occurs after the last ozone season that influences the attainment status of the "moderate" 8-hour ozone nonattainment areas that will receive an attainment date no later than April 2010. We also note that its analysis indicates that the level of control in the first phase is constrained by the amount of control equipment that can be installed by a limited labor force, and providing an earlier compliance deadline might reduce the reductions feasible in the first phase. We request comment on whether the first phase deadline should be as proposed, or adjusted earlier or later, in light of these competing factors.

For SO_2, if States choose to control EGUs through the model cap and trade program, emissions banking provides incentives that lead to steadily declining emissions and thus results in additional benefits before the 2010 and 2015 reductions. However, it appears that it would help several States to reach attainment by CAA deadlines if the second phase emissions cap went into effect earlier, especially for NO_X. This needs to be balanced against the ability of the power industry to do substantially more at that time. The EPA is soliciting comment on the timing of the second phase.

The EPA strongly encourages each State to consider reserving a portion of its allowance budget for an auction. Proceeds from the auction would be fully retained by the State to be used as they see fit. Some possible suggestions for auction revenue that States may want to choose will be further explored in a supplemental notice. For example, a State could develop a program that uses the revenue to provide incentives for additional local reductions within nonattainment areas.

The EPA sees benefits in requiring States to reserve a portion of their budgets for auction, but has concerns about whether such a requirement would intrude on State prerogatives.[87] We solicit comment on this issue.

H. Budgets for Federally-Recognized Tribes

In the 1990 CAA amendments, Congress recognized our obligation to treat Tribes in a manner similar to States. Currently, we are not aware of any EGUs in Indian country in the eastern and central U.S. that could potentially be affected by the interstate air quality rule.

The Tribal air programs are relatively new and Tribes are just now establishing their capacity to develop air quality management plans and beginning to participate in national policy setting processes such as this rulemaking. In addition, past Federal policy limited the economic development and thus the number of emissions sources that might otherwise have been built on Tribal lands. However, many Tribes are currently encouraging economic development on their lands, particularly in the area of energy generation.

[87] *See Virginia* v. *EPA*, 108 F.3d 1397 (D.C. Cir. 1997).

In the NO_X SIP Call, EPA did not explicitly consider the issue of Tribal lands and we made no specific provisions for them. One consequence is that Tribal implementation plans—even ones that cover new or existing sources on Tribal lands—apparently are not subject to any of the requirements of the NO_X SIP Call rule. We now realize that we should adopt specific provisions for Tribal lands in today's proposed rulemaking. For States, which have substantial emissions now and corresponding impacts on nonattainment in other States, we have focused in this proposal on what emissions reductions are needed to eliminate existing significant contributions to nonattainment. For Tribes, since there are few sources on Tribal lands now and no EGUs, we should consider what increases are possible without causing significant contributions to nonattainment in State lands and other Tribal lands.

Title IV SO_2 allowances have been provided to EGUs. Because there are no EGUs on Tribal lands, title IV allowances have not been awarded to any EGUs on Tribal lands. Additionally, without EGUs there is no historical heat input for use in calculating an allowance budget for NO_X for Tribal lands. In our discussions prior to this proposal, Tribal representatives have expressed concern that budgets based on existing emissions effectively exclude them from the program unless Tribes buy allowances from the surrounding States. If Tribes do buy allowances, they will be effectively subsidizing the development and inadequate environmental planning of surrounding States. In this rulemaking, we are taking into consideration the past inequities created by Federal policy and traditionally depressed development in Indian country, as well as the need to make progress in air quality.

We are not proposing specific provisions for Tribal lands today. We invite comment generally and on the following specific questions regarding allowance allocation to Tribes:

(1) Should allowance budgets for Tribes be created by the rule separately from State allowance budgets, or be deducted from the proposed State budgets? On what basis or criteria should either approach be implemented?

(2) Alternatively, should the rule set an allowance pool for Tribes in the aggregate with some further process by EPA or by the Tribes collectively to allocate the allowances to specific Tribes? Should the allowance allocation issues be deferred entirely to separate action(s) later? Should any immediate or

eventual allocations to individual Tribes be based on current emissions, existing contracts for new sources, population, land base, or some other factor(s)? Some Tribes may have concerns that deferral of allowance allocations to individual Tribes does not adequately recognize the sovereignty of individual Tribal nations. There may also be concern that continued uncertainty in the allowances available to the individual Tribes may discourage planning for development.

(3) Should allowances be tradeable among Tribes once allocated? Should they be bankable?

(4) Because the SIPs do not generally apply in Indian country, the system for regulating sources on Tribal land for purposes of limiting transport will need to be implemented through either a Tribal implementation plan or a Federal implementation plan. We invite comment on the best mechanism to implement the budgets.

We recognize that information on economic development and potential for growth may be sensitive for the Tribes to share with EPA or a public docket. We request input from the Tribes on how to determine the allowance needs for the Tribes.

VII. State Implementation Plan Schedules and Requirements

This section describes the dates for submittal and implementation of the interstate transport SIPs that today we propose to require, and discusses those dates in the context of the attainment dates and SIP submittal requirements for the downwind nonattainment areas. In addition, this section describes the required SIP elements that we propose today.

A. State Implementation Plan Schedules

1. State Implementation Plan Submission Schedule

Clean Air Act section 110(a)(1) requires each State to submit a SIP to EPA "within 3 years * * * after the promulgation of a [NAAQS] (or any revision thereof)." Section 110(a)(2) makes clear that this SIP must include, among other things, the "good neighbor" provisions required under section 110(a)(2)(D). These provisions may be read together to require that each upwind State submit, within three years of a NAAQS revision, SIPs that address the section 110(a)(2)(D) requirement.

The $PM_{2.5}$ and 8-hour ozone NAAQS revisions were issued in July 1997. More than 3 years have already elapsed since promulgation of the NAAQS, and States have not submitted SIPs to address their section 110(a)(2)(D) obligations under the new NAAQS. We further recognize that until recently, there was substantial uncertainty as to whether each NAAQS would be remanded to EPA, and that this uncertainty would, as a practical matter, render more complex the upwind States' task of developing transport SIPs.

In addition, today's proposal makes available a great deal of data and analysis concerning air quality and control costs, as well as policy judgments from EPA concerning the appropriate criteria for determining whether upwind sources contribute significantly to downwind nonattainment under section 110(a)(2)(D). We recognize that States would face great difficulties in developing transport SIPs without these data and policies. In light of these factors and the fact that States can no longer meet the original three-year submittal date, we are proposing that SIPs to reduce interstate transport, as required by this proposal, be submitted as expeditiously as practicable, but no later than 18 months from the date of promulgation. The EPA intends to promulgate today's proposed rule between approximately December 2004 and June 2005. In this case, the SIPs required today would be due between approximately July and December 2006.

By comparison, in the NO_X SIP Call rulemaking, EPA provided 12 months for the affected States to submit their SIP revisions. One of the factors that we considered in setting that 12-month period was that upwind States had already, as part of the Ozone Transport Assessment Group process begun three years before the NO_X SIP Call rulemaking, been given the opportunity to consider available control options.

Since today's proposal requires affected States to control both SO_2 and NO_X emissions, and to do so for the purpose of addressing both the $PM_{2.5}$ and 8-hour ozone NAAQS, we believe it is reasonable to allow affected States more time than was allotted in the NO_X SIP Call to develop and submit transport SIPs. Since we plan to finalize this rule no later than mid-2005, SIP submittals would be due no later than the end of 2006. Under this schedule, upwind States' transport SIPs would be due before the downwind States' $PM_{2.5}$ and 8-hour ozone nonattainment SIPs, under CAA section 172(b). We expect that the downwind States' 8-hour ozone nonattainment area SIPs will be due by May 2007, and their nonattainment SIPs for $PM_{2.5}$ by January 2008.[88]

The SIP submittal date proposed today should be considered in the context of the downwind nonattainment area SIP submittal schedules and attainment dates. Under CAA section 172(b), the downwind nonattainment SIPs are due no later than three years after the designations. The EPA expects to designate $PM_{2.5}$ areas by December 31, 2004, and to require the nonattainment area SIPs by three years of the designation. The EPA is required to designate 8-hour ozone areas by April 15, 2004, with an effective date of May 2004, and to require the nonattainment area SIPs by three years of the designation.

Accordingly, today's proposal requires the submittal of the upwind transport SIPs before the downwind nonattainment area SIPs will be due. This sequence is consistent with the provisions of both section 110(a)(1)–(2), which provides that the submittal period for the transport SIPs runs from the earlier date of the NAAQS revision; and section 172(b), which provides that the submittal period for the nonattainment area SIPs runs from the later date of designation.

The earlier submittal date for transport SIPs is also consistent with sound policy considerations. The upwind reductions required today will facilitate attainment planning by the downwind States. Further, most of the downwind States that will benefit by today's rulemaking are themselves upwind contributors to problems further downwind, and, thus, are subject to the same requirements as the States further upwind. The reductions these downwind States must implement due to their additional role as upwind States will help reduce their own $PM_{2.5}$ and 8-hour ozone problems on the same schedule as emissions reductions for the upwind States.

2. Implementation Schedule

Section 110(a)(2)(D) requires SIPs to "contain adequate provisions * * * prohibiting * * * [emissions that] will * * * contribute significantly to nonattainment in * * * any other State. * * *" The phrase "will * * * contribute significantly" suggests that EPA should establish the significance of the emissions' contribution, and require their prohibition, as of a time in the future. However, the provision does not, by its terms, indicate the applicable date in the future; nor does it address the future period of time.

For today's proposal, EPA believes that determining significant

[88] The actual dates will be determined by relevant provisions in the CAA and EPA's interpretation of these provisions published in upcoming implementation rules for the $PM_{2.5}$ and 8-hour ozone NAAQS.

contribution as of 2010, and requiring implementation of the reductions by January 1, 2010, is a reasonable application of the statutory provisions. As discussed in section VI, emissions controls for EGUs may be feasibly implemented by that time. As a result, January 1, 2010 is the date by which we can confidently predict that highly cost-effective emission reductions from EGUs can begin, considering cost broadly to encompass many factors, including engineering feasibility and electricity supply reliability risks.

Emissions reductions by this date will also provide significant air quality benefits to the downwind nonattainment areas. We expect that the attainment date for numerous downwind areas will be 2010 or later, so that these reductions will facilitate attainment. For ozone nonattainment areas, the reductions will reduce the amount of nonattainment. For $PM_{2.5}$ nonattainment areas, the reductions will have the same effect, and help bring those areas into attainment. Indeed, we believe that the anticipation of the optional trading program beginning in 2010 will create incentives for reductions in SO_2 emissions prior to that date. Therefore, today's proposal will have benefits for progress towards attainment with the $PM_{2.5}$ NAAQS in the years between finalization of this rule and 2010. Further discussion of these air quality benefits is included in section IX.

As discussed in section VI, feasibility considerations warrant deferring a portion of the emissions reductions to 2015. As discussed in section IX, these reductions will provide air quality benefits at that time, as well, and, as in the case with the 2010 emission reductions, we expect that the anticipation of tighter controls will likely lead to SO_2 emissions reductions prior to 2015.

B. State Implementation Plan Requirements

Today's proposal requires States to submit SIPs that contain controls sufficient to eliminate specified amounts of emissions. The EPA determined these amounts through the application of highly cost-effective controls to the EGU source category. The amount of the emissions reduction is determined by comparing the amount of EGU emissions in the base case—that is, in the absence of controls—to the amount of emissions after implementation of the controls. Section VI contains a more detailed discussion of the process for determining the amounts of emissions in the base case.

As noted elsewhere, EPA is gathering information concerning certain other source categories. However, EPA does not, at present, have information upon which to propose a determination that any other source categories may achieve specific emissions reductions at a cost that could be considered highly cost effective.

To achieve the required amount of emissions reductions, States may impose emission limits on other sources—in addition to EGUs—if they choose. The EPA is considering what additional requirements are needed to ensure that these limits are met. Overarching considerations include whether the requirements (i) provide certainty that all emissions that EPA determined to contribute significantly will be eliminated both at the State and regional level; (ii) ensure that contributions will continue to be eliminated in future years; and (iii) ensure that the control requirements can be feasibly implemented.

The EPA considered two main approaches to the SIP requirements: a budget (*i.e.*, cap) approach, and an emission reduction approach. The EPA is proposing a hybrid approach that we believe incorporates the best elements of both approaches while minimizing the shortfalls of both approaches.

1. The Budget Approach

In its most rigorous form, a budget approach would require a statewide cap, that is, the capping of aggregate emissions from all source categories in each State. Mechanisms would be set up to ensure that the overall budget was not exceeded. These mechanisms could require individual source categories to meet sub-budgets or could provide for emission shifting between source categories. Subjecting each State throughout the region to aggregate emissions budgets would provide great certainty that the amount of emissions identified as contributing significantly to nonattainment had been eliminated. This approach would also assure that the significant contribution was fully addressed for future years because any increase in activity across all emission sources would have to occur within the budget, that is, without generating additional emissions. If all States applied such an approach, it would also assure that emissions from a source within a given source category would be permanently reduced and not merely shifted to another source within the region, as could occur if sources in one State were controlled under a budget but similar sources in another State were not.

A less rigorous approach would require enforceable budgets for only some source categories, namely, those that were required to make the emissions reductions. Under this approach, there would be less certainty that all States will continue to not contribute significantly (in terms of the air quality component) in future years because growth in overall emissions may still occur.

The U.S. EPA and State environmental agencies have successfully applied budget approaches to certain source categories and groups of source categories. For instance, the title IV requirements of the CAA applied a SO_2 budget to most large EGUs. The Ozone Transport Commission (OTC) NO_X budget trading program applied an ozone season NO_X budget to large EGUs and non-EGU boilers and turbines, and many States have adopted the same approach to meet the requirements of the NO_X SIP Call.[89] These successes demonstrate that budget programs can work for large stationary sources. These types of sources can accurately monitor emissions at the unit level, and these sources are manageable in number, so that overall emissions can be determined using this unit level data.

On the other hand, there has been virtually no experience with budget programs for mobile and area sources, due to challenges in accounting for emissions from these types of sources. Emissions from these sources are typically estimated using emission factors and estimated emission data, so that there is much less certainty about the accuracy of these amounts of emissions. Additionally, monitoring at the unit level and tracking unit level emissions would be much more difficult because of the large number of small sources involved.

As noted above, EPA believes that there are benefits from requiring a State to impose a cap on EGUs. We also believe that there would be benefits from requiring a State to impose a cap on any source category on which the State imposes controls. One benefit would be a permanent limit on the amount of emissions from that category to assure the reductions in emissions that significantly contribute to nonattainment in affected downwind States. We solicit comment on the approach of requiring States to impose caps on any source categories which the State chooses to regulate under the rule proposed today.

[89] These budget approaches authorize trading among sources, but other control methodologies, such as emission rate controls, may also authorize trading. See U.S. EPA, "Improving Air Quality with Economic Incentive Programs," (January 2001).

2. The Emissions Reduction Approach

Under the emissions reduction approach, SIPs must impose control requirements that typically consist of an emission rate limit or, possibly, application of a specified type of technology, but not an emissions cap. These control requirements, when implemented by the affected sources in the implementation years, must result in the amount of emission reductions that EPA required through the highly cost-effective calculations described in section VI.

This approach is most useful when a State chooses to apply the control requirements to a source category for which current source-monitoring methods do not permit specific emissions quantification for each source, and for which shifts in emissions-generating activity are unlikely to result from the control program. This limitation in the methodology may result because, among other possible reasons, (i) the source's emissions generating activities are of a type for which no accurate quantification methodology exists; (ii) such a methodology would be unreasonably expensive to apply to the source; or (iii) the sources are too numerous.

Even so, to ensure that the desired emissions reductions are achieved, this methodology requires accurate baseline emission estimates, which, as a practical matter, may be difficult to develop in light of the uncertainties in estimating emissions from the affected source types. If the baseline estimates are high, States may achieve credit for emissions reductions they will not in fact achieve (by reducing emissions to a certain emission rate from the incorrectly high baseline emission rate). Additionally, while this approach may assure similar emissions reductions to the budget approach in the early years following implementation, growth in activity levels in the controlled source categories would likely lead to growth in emissions in later years, which in turn may adversely affect downwind nonattainment areas.

Although the emissions reduction approach has limitations, EPA believes it is the most workable approach for some source categories, such as mobile and area sources, for which there is little or no experience in using the budget approach and for which the available emissions quantification techniques are too imprecise to support the budget approach.

3. The EPA's Proposed Hybrid Approach

The EPA proposes today to require each affected State to submit a SIP containing control requirements that will assure a specified amount of emissions reductions. These amounts would be computed with reference to specified control levels for EGUs, which EPA has determined to be highly cost effective.

States may meet their emissions reduction requirements by imposing controls on any source category they choose. If they choose the EGU source category, they must impose a cap because this category may feasibly implement a cap. If States choose to get emissions reductions from other source categories, they may implement the emissions reduction approach, that is, they need not implement caps, but rather may implement other forms of controls. Even so, EPA strongly encourages States to control source categories for which workable budget programs can be developed, and to require the budget approach for those sources to which it can feasibly be applied.[90]

The EPA is proposing specific requirements that States must meet, depending on which source categories they choose to control. These requirements are intended to provide as much certainty as possible that the controls will eliminate the amounts of significant contributions.

a. Requirements if States Choose To Control EGUs

As explained above, States must apply the budget approach if they choose to control EGUs. That is, they must cap EGUs at the level that assures the appropriate amount of reductions. We believe that this is the preferable approach for complying with today's proposed rule.

Moreover, as discussed in sections VI and VIII, States that choose to allow their EGUs to participate in EPA-administered interstate SO_2 and NO_X emissions trading program must adhere to EPA's model trading rules, which we intend to propose in the SNPR. For SO_2 sources, these rules will require the States to allocate control obligations to sources in a manner that mirrors the sources' title IV allowance allocations, although EPA is considering certain variations that are described in section VI.

With respect to monitoring, recordkeeping, and reporting requirements, most EGUs are already subject to the requirements of 40 CFR part 75 to demonstrate compliance with the title IV SO_2 provisions. In addition, many EGUs are also subject to part 75 due to SIP requirements under the NO_X SIP Call. The EPA believes that part 75 provides accurate and transparent accounting of emissions from this source category. Therefore, EPA proposes to require States, if they apply controls to EGUs, to subject EGUs to the requirements of part 75.

As explained in sections VI and VIII, today's proposed SO_2 emissions reductions requirement, when applied to EGUs subject to the title IV allowance programs, would result in a cap that, in turn, would create surplus title IV allowances. These surplus allowances, if allowed to be traded, may have adverse impacts in and outside of the States directly affected by today's proposal. In particular, the large number of these allowances that become available may depress their price, which may lead to even more of them being purchased and used in States not affected by today's proposed rule.

To prevent these impacts, EPA is proposing that SIPs assure that the State's title IV allowances exceeding the emissions that the State's EGUs may emit under the rule proposed today are not used in a manner that undermines the rule proposed today. As a practical matter, SIPs may need to require the retirement or elimination of certain of the title IV allowances. The number of retired or eliminated allowances may well equal the difference between the number of title IV allowances allocated to a State and the SO_2 budget that the State sets for EGUs under today's proposed rule. For example, assume that a State's EGUs are allocated a total 5,000 SO_2 allowances under title IV (each allowance authorizes one ton of SO_2 emissions). Assume further that today's proposed rule requires the State to reduce its SO_2 emissions by 2,500 tons. Assume even further that the State chooses to achieve all of the required reductions from EGUs, beginning January 1, 2010. Under these circumstances, the SIP must include a mechanism to retire or eliminate the remaining 2,500 allowances.

The EPA believes that this proposed requirement to retire or eliminate surplus allowances applies regardless of whether or not a State participates in the EPA-managed trading system. If the State does not participate in the EPA-managed trading system, it may choose

[90] It should be noted that even if a State uses a budget approach for a source category within the State, it is possible that production may shift to another part of the transport region, so that the State's claimed emission reductions may in fact simply represent emissions shifted to another part of the transport region.

the specific method to retire or eliminate surplus allowances from its sources. If it chooses the EPA-managed trading system, it must adhere to the provisions of the model trading rule, which are broadly outlined in section VIII.

States may allow EGUs to demonstrate compliance with the State EGU SO_2 emission budget by using (i) allowances that were banked (that is, issued for years earlier than the year in which the source is demonstrating compliance), or (ii) title IV allowances from the same year purchased from sources in other States.

b. Requirements if States Choose To Control Sources Other Than EGUs

If a State chooses to require emissions reductions from only EGUs, then its SIP revision submitted under the rule proposed today need contain only provisions related to EGUs, as described above. The State need not adopt or submit, under the rule proposed today, any other provisions concerning any other source categories.[91]

On the other hand, if a State chooses to require emissions reductions from sources other than EGUs, the State must adopt and submit SIP revisions, and supporting documentation, designed to quantify the amount of reductions from the sources and to assure that the controls will achieve that amount of reductions. The EPA is not proposing today that the State be required to cap those sources. However, EPA solicits comment on whether to require States that choose to control sources other than EGUs to cap those sources.

To demonstrate the amount of emissions reductions from the controlled sources, the State must take into account the amount of emissions attributable to the source category both (i) in the base case—that is, in the implementation year (2010 and 2015) without assuming SIP-required reductions from that source category under today's proposed rule—and (ii) in the control case. Both scenarios (base case and control case) are necessary to determine the amount of emissions reductions that will result from the controls. As noted above, section VI contains a more detailed discussion of the process for determining the amounts of emissions in the base case.

The EPA intends to propose in the SNPR monitoring, recordkeeping, and reporting requirements for sources other than EGUs. Further, EPA intends to include proposed rule language for these requirements. Commenters will have an opportunity to comment following publication of the SNPR. As a result, EPA is not soliciting comment on this subject now. Even so, EPA intends to consider any comments submitted on this subject that commenters may wish to submit.

VIII. Model Cap and Trade Program

In today's action, we are outlining multi-State cap and trade programs for SO_2 and NO_X that States may choose as a cost-effective mechanism to achieve the required air emissions reductions. Use of these cap and trade programs will not only ensure that emissions reductions under the proposed rulemaking are achieved, but also provide the flexibility and cost effectiveness of a market-based system. This section provides background information, a description of the cap and trade programs, and an explanation of how the cap and trade programs would interface with other State and Federal programs. It is EPA's intent to propose model SO_2 and NO_X cap and trade rules in a future SNPR that States could adopt.

By adopting the model rules, States choose to participate in the cap and trade programs, which are a fully approvable control strategy for achieving emissions reductions required under today's proposed rulemaking. Should a State choose to participate in the cap and trade programs, EPA's authority to cooperate with and assist the State in the implementation of the cap and trade program(s) would reside in both State law and the CAA. With respect to State law, any State that elects to participate in the cap and trade programs as part of its SIP will be authorizing EPA to assist the State in implementing the cap and trade program with respect to the regulated sources in that State. With respect to the CAA, EPA believes that the Agency's assistance to those States that choose to participate in the cap and trade programs will facilitate the implementation of the programs and minimize any administrative burden on the States. One purpose of title I of the CAA is to offer assistance to States in implementing title I air pollution prevention and control programs (42 U.S.C. 101(b)(3)). In keeping with that purpose, section 103(a) and (b) generally authorize EPA to cooperate with and assist State authorities in developing and implementing pollution control strategies, making specific note of interstate problems and ozone transport. Finally, section 301(a) grants EPA broad authority to prescribe such regulations as are necessary to carry out its functions under the CAA. Taken together, EPA believes that these provisions of the CAA authorize EPA to cooperate with and assist the States in implementing cap and trade programs to reduce emissions of transported SO_2 and NO_X that contribute significantly to ozone and $PM_{2.5}$ nonattainment.

To inform the current rulemaking process, EPA recently hosted two workshops in July and August of 2003 to listen to States and multi-State air planning organization's experience with the NO_X SIP Call program to date: What has worked well, what may not have worked well, and what could be improved. (The EPA Web site[92] provides information on these workshops.) Workshops such as these have played an important role in the development and implementation of the NO_X SIP Call and will help in the development of this rule.

This section in today's action describes, on a generally conceptual level, the cap and trade program. EPA will publish, in a future SNPR, a more detailed description of the proposed rules, as well as model rules. As a result, EPA is not soliciting comment on this section in today's action. Interested persons will have a full opportunity to comment on all aspects of this cap and trade program through the SNPR. Even so, EPA recognizes that continued stakeholder input on the cap and trade programs described in this section may be useful concerning the programmatic implications of addressing multiple environmental issues (*i.e.*, $PM_{2.5}$ and ozone) with synchronized cap and trade programs for SO_2 and NO_X. Accordingly, EPA intends to review comments that may be submitted on all of the program elements described in today's NPR.

A. Application of Cap and Trade Approach

1. Purpose of the Cap and Trade Programs and Model Rules

In the cap and trade programs, EPA is proposing to jointly implement with participating States a capped market-based program for EGUs to achieve and maintain an emissions budget consistent with the proposed rulemaking. Specifically, EPA has designed today's proposal to assist States in their efforts to: (1) Improve air quality and achieve the emissions reductions required by the proposed rulemaking; (2) offer compliance flexibility for regulated sources; (3) reduce compliance costs for sources controlling emissions; (4)

[91] Of course, the State may be obligated to submit SIP revisions covering other source categories under applicable CAA provisions other than section 110(a)(2)(D).

[92] *http://www.epa.gov/airmarkets/business/noxsip/atlanta/atl03.html.*

streamline the administration of programs to reduce multiple pollutants for States; and (5) ensure that emission reductions are occurring and that results are publicly available. In addition to realizing these benefits of a cap and trade program, EPA also seeks to create as simple a regulatory regime as possible by applying a single, comprehensive regulatory approach to controlling multiple pollutants across multiple jurisdictions.

Beyond choosing to use a cap and trade program, State adoption of the model rule would ensure consistency in certain key operational elements of the program among participating States. Uniformity of the key operational elements across the region is necessary to ensure a viable and efficient cap and trade program with low transaction costs and minimum administrative costs for sources, States, and EPA. (These necessary elements are discussed in section B.3.). States will continue to have flexibility in other important program elements (*e.g.*, allowance allocations, inclusion of additional measures to address persistent local attainment issues).

2. Benefits of Participating in a Cap and Trade Program

a. Advantages of Cap and Trade Over Command-and-Control

When designed and implemented properly, a cap and trade program offers many advantages over traditional command-and-control and project-by-project emission reduction credit trading programs. There are several advantages of a well-designed cap and trade system that include: (1) Control of emissions to desired levels under a fixed cap that is not compromised by future growth; (2) high compliance rates; (3) lower cost of compliance for individual sources and the regulated community as a whole; (4) incentives for early emissions reductions; (5) promotion of innovative compliance solutions and continued evolution of generation and pollution control technology; (6) flexibility for the regulated community (without resorting to waivers, exemptions and other forms of administrative relief that can delay emissions reductions); (7) direct legal accountability for compliance by those emitting; (8) coordinated program implementation that efficiently applies administrative resources while enhancing compliance; and (9) transparent, complete, and accurate recording of emissions. These benefits result primarily from the rigorous framework established by a cap and trade program that provides flexibility in compliance options available to sources and the monetary reward associated with avoided emissions in a market-based system. The cost of compliance in a market-based program is reduced because sources have the freedom to pursue various compliance strategies, such as switching fuels, installing pollution control technologies, or buying emission allowances from a source that has over-complied. Since reducing emissions to levels below the allocations for a source allows them to sell excess allowances on the market, this program promotes cost effective pollution prevention, and encourages innovations in less-polluting alternatives and control equipment.

A market-based system that employs a fixed, enforceable tonnage limitation (or cap) for a source or group of sources provides the greatest certainty that a specific level of emissions will be attained and maintained. With respect to transport of pollution, an emissions cap also provides assurance to downwind States that emissions from upwind States will be effectively managed over time. The capping of total emissions of pollutants over a region and through time ensures achievement of the environmental goal while allowing economic growth through the development of new sources or increased use of existing sources. In an uncapped system (where, for example, sources are required only to demonstrate that they meet a given emission rate) the addition of new sources to the regulated sector or an increase in activity at existing sources can increase total emissions even though the desired emission rate control is in effect.

In addition, the reduced implementation burden for regulators and affected sources benefits taxpayers and those who must comply with the rules. This streamlined administration allows a relatively small number of government employees to successfully manage the emissions of many sources by (1) minimizing the necessity for case-by-case decisions, and (2) taking full advantage of electronic communication and data transfer to track compliance and develop detailed inventories of emissions and plant operations.

b. Application of the Cap and Trade Approach in Prior Rulemakings

i. Title IV

Title IV of the CAA Amendments of 1990 established the Acid Rain Program, a program that utilizes a market-based cap and trade approach to require power plants, to reduce SO_2 emissions by 50 percent from 1980. At full implementation after 2010, emissions will be limited, or capped, at 8.95 million tons in the contiguous United States. The Acid Rain SO_2 Program is widely acknowledged as a model air pollution control program because it provides significant and measurable environmental and human health benefits with low implementation costs.

Individual units are directly allocated their share of the total allowances—each allowance is an authorization to emit a ton of SO_2—based upon historical records of the heat content of the fuel that they combusted in 1985–1987. Units that reduce their emissions below the number of allowances they hold, may trade excess allowances on the open market or bank them to cover emissions in future years. Allowances may be purchased through the open market or at EPA-managed auctions. Each affected source is required to surrender allowances to cover its emissions each year. Should any source fail to hold sufficient allowances, automatic penalties apply. In addition to financial penalties, sources either will have allowances deducted immediately from their accounts or, if this would interfere with electric reliability, may submit a plan to EPA that specifies when allowances will be deducted in the future.

The Acid Rain Program requires affected sources to install systems that continuously monitor emissions. The use of continuous emissions monitoring systems (CEMS) is an important component of the program that allows both EPA and sources to track progress, ensure compliance, and provide credibility to the cap and trade component of the program.

While title IV does provide for an Acid Rain Permit, this is a simple permit that does not incorporate source specific requirements, but rather requires the source to comply with the standard rules of the program. The Acid Rain Permit has been easily incorporated into the title V permit process and does not require the typically resource intensive, case-by-case review associated with other permits under command-and-control programs.

The Acid Rain Program has achieved major SO_2 emissions reductions, and associated air quality improvements, quickly and cost effectively. In 2002, SO_2 emissions from power plants were 10.2 million tons, 41 percent lower than 1980.[93] (2002 Acid Rain Progress

[93] U.S. EPA, EPA Acid Rain Program: 2002 Progress Report (EPA 430–R–03–011), November 2003. Available at *http://www.epa.gov/airmarkets/cmprpt/arp02/2002report.pdf.*

Report.) These emission reductions have translated into substantial reductions in acid deposition, allowing lakes and streams in the Northeast to begin recovering from decades of acid rain. In addition, substantial improvements in air quality have occurred under the Acid Rain Program. Fine particle exposures have been reduced, providing significant benefits to public health. These benefits include the annual reduction of thousands of premature mortalities, thousands of cases of chronic bronchitis, thousands of hospitalizations for cardiovascular and respiratory diseases.

Cap and trade under the Acid Rain Program has created financial incentives for electricity generators to look for new and low-cost ways to reduce emissions, and improve the effectiveness of pollution control equipment, at costs much lower than predicted. The cap on emissions, automatic penalties for noncompliance, and stringent emissions monitoring and reporting requirements ensure that environmental goals are achieved and sustained, while allowing for flexible compliance strategies which take advantage of trading and banking. The level of compliance under the Acid Rain Program continues to be uncommonly high, measuring over 99 percent.

ii. Ozone Transport Commission NO_X Budget Program

The Ozone Transport Commission's (OTC) NO_X Budget Program was a cap and trade program to reduce NO_X emissions from power plants and other large combustion sources in the Northeast. The OTC was established under the CAA Amendments of 1990 to help States in the Northeast and Mid-Atlantic region meet the NAAQS for ground-level ozone. The NO_X Budget Program set a regional budget on NO_X emissions from power plants and other large combustion sources during the ozone season (from May 1 through September 30) beginning in 1999.

The OTC NO_X Budget Program has significantly reduced NO_X emissions from large combustion facilities in the Northeast and Mid-Atlantic region with total regional emissions in 2002 approximately 60 percent below 1990 levels; well under target levels. Significant reductions in ozone season NO_X emissions have occurred in all States across the region. In addition, the emission reductions have proven to be cost effective with the cost of NO_X allowances stabilized below original projections.[94]

The OTC States generally folded their SIP requirements under the OTC NO_X Budget Program into the SIP revisions they submitted with the NO_X SIP Call. The NO_X Budget Program was incorporated into the NO_X SIP Call. The 2003 ozone season marked the first year of compliance with the NO_X SIP Call for the OTC States.

iii. NO_X SIP Call

The NO_X SIP Call, finalized in 1998, requires ozone season (*i.e.*, summertime) NO_X reductions across a region which includes most of the OTC States and southeastern and midwestern States that were found by EPA to have sources that contribute significantly to another State's ongoing ozone NAAQS nonattainment problems. The NO_X SIP Call proposed a cap and trade program as a way to make cost-effective NO_X reductions. Each of the States required to submit a NO_X SIP under the NO_X SIP Call chose to adopt the cap and trade program regulating large boilers and turbines. Each State based its cap and trade program on a model rule developed by EPA. This model rule included key elements such as the use of continuous emissions monitoring (CEMS) and 40 CFR part 75 monitoring and reporting requirements, and a single party that is legally responsible for compliance. Some States essentially adopted the full model rule as is, while other States adopted the model rule with changes to the sections that EPA specifically identified as areas in which States may have some flexibility. The NO_X SIP Call cap and trade program, modeled closely after the OTC NO_X Budget Program takes effect in 2004. When it does so, it expands from the OTC States to eleven additional States in 2004. The EPA intends to draw heavily upon this and other experience in developing model SO_2 and NO_X cap and trade programs.

c. Regional Environmental Improvements Achieved Using Cap and Trade Programs

One concern with emissions trading programs is that the flexibility associated with trading might allow sources or groups of sources to increase emissions, resulting in areas of elevated pollution or "hot spots." The environmental results observed under the Acid Rain Program have instead indicated that the combination of trading with a stringent emissions cap results in substantial reductions throughout the region, with the greatest reductions achieved in the areas where pollution was originally the highest.

Since 1990, SO_2 and sulfate concentrations at CASTNET sites have been reduced substantially in the areas where concentrations were highest before the Acid Rain Program. (Acid Rain Program Progress Report 2002). All sites in the East showed reductions in SO_2 and sulfate 3 year average concentrations between 1990–1992 and 2000–2002. The largest decreases in SO_2 concentrations were observed at sites where SO_2 emissions and monitored SO_2 concentrations were highest before the program (from Illinois, to northern West Virginia, across Pennsylvania, to western New York). CASTNET sites throughout the broader eastern region also show a substantial reduction in sulfate concentrations, with the largest decreases in sulfate levels occurring along the Ohio River Valley from Illinois to West Virginia, Pennsylvania, and the mid-Atlantic states.

Independent analyses, in addition to those conducted by EPA, have shown that emissions trading under this type of program has not resulted in the creation of "hot spots" because trading has resulted in emissions reductions being achieved in areas where emissions were highest before the program.[95] The Environmental Law Institute, Environmental Defense, and the Massachusetts Institute of Technology's Center for Energy and Environmental Policy have all examined emissions trading under the Acid Rain Program and none have concluded that the program has resulted in hot spots of high emissions. To the contrary, the highest emitting sources have tended to reduce emissions by the greatest amount. This is the case, in part, because trading occurs under a nationwide cap that represents a reduction in total emissions and improvements in regional air quality. The flexibility of a cap and trade system provides a mechanism for achieving established emission goal(s)at lowest possible cost. The most cost effective opportunities for reductions are at the larger, more efficient coal-fired units that have modest (or no) controls and are geographically dispersed.

Further support for trading actually reducing "hot spots" was found by Resources for the Future. Resources for the Future, a non-partisan environmental advocacy group,

[94] Ozone Transport Commission. NO_X Budget Program 1999–2002 Progress Report, March 2003. Available at *http://www.epa.gov/airmarkets/otc/otcreport.pdf.*

[95] Environmental Law Institute (*http://www.epa.gov/airmarkets/ articles/so2trading-hotspots_charts/pdf*), Environmental Defense (*http://www.environmentaldefense.org/ documents/645_SO2.pdf*) and MIT's Center for Energy and Environmental Policy Research (*http://web.mit.edu/ceepr/www/2003-015.pdf*).

modeled air quality and health benefits under the trading program and under a non-trading scenario and found that trading actually resulted in additional benefits because emissions reductions took place in areas where they were more environmentally effective.[96]

Cap and trade programs are designed to reduce emissions of numerous polluting sources by significant amounts over large geographic areas. The trading mechanism does not replace the requirement to meet the NAAQSs at the local level, but rather helps achieve this requirement through significant reductions in background pollution. Thus, State and local governments will continue to have the obligation and the authority under the CAA to assure that the NAAQS are met.

Nearly 10 years of experience with the Acid Rain Program for SO_2 has clearly demonstrated that market-based cap and trade programs are an effective vehicle for achieving broad improvements in air quality by reducing emissions of a regionally transported air pollutant. More recently, the OTC's regional NO_X program also has shown the value of a cap and trade approach for NO_X reductions. The more stringent SO_2 and NO_X caps proposed in this rulemaking will build on this track record of success.

B. Considerations and Aspects Unique to the SO_2 Cap and Trading Program

1. SO_2 Cap and Trade Program Overview

This section of today's proposal outlines an SO_2 cap and trade program which builds upon the concepts applied in the cap and trade programs described in section VIII.A. This section discusses elements unique to the proposed SO_2 trading program, paying particular attention to those aspects that significantly differ from the corresponding provisions in existing programs. (Additional details on the SO_2 and NO_X trading program may be found in section VIII.D, which describes major program elements that must be consistent across States in order for EPA to implement a trading program.)

While key considerations and program elements are outlined in today's proposed rule, a complete model cap and trade rule will be proposed by EPA in a future SNPR. In addition to a model rule, the SNPR will address other issues such as allocations and voluntary measures for States to address persistent local non-attainment issues.

The proposed SO_2 cap and trade program would apply to the large power generators in the transport region. (See section VI of today's rule for a discussion of the emission budgets and the core sources.) States would have some flexibility to include other sources or source categories in the trading program should they demonstrate their ability to measure the emissions from these other sources to the same standards required of the core trading sources.

The units affected by today's SO_2 rule are already regulated by EPA. EPA is committed to a transition that ensures continued environmental progress, preserves the integrity of existing emission trading markets, and minimizes confusion and cost for the public, sources and regulators. Section VIII.B.2 below discusses the interactions between today's proposal and existing programs by presenting analysis and implementation options. A discussion of the applicable sources is contained in section VIII.D.1.

2. Interactions With Existing Title IV Acid Rain SO_2 Cap and Trade Program

As discussed above, title IV of the CAA requires reductions in SO_2 emissions from power plants to abate acid rain and improve public health using a cap and trade approach. Further, title I of the CAA requires EPA to help States develop and design implementation plans to meet the NAAQS. To achieve that end, today's action proposes a regional rule to reduce ambient concentrations of $PM_{2.5}$, as mandated by the CAA. The SO_2 program establishes a model cap and trade system for reducing emissions that States can adopt in order to help meet the NAAQS.

As EPA developed this regulatory action, great consideration was given to interactions between the existing title IV program and a rulemaking designed to achieve significant reductions in SO_2 emissions beyond title IV. Requiring sources to reduce emissions beyond the title IV mandates has implications for the existing title IV SO_2 program which are both environmental and economic. In the absence of a method for incorporating the statutory requirements of title IV, a rule that imposes a tighter cap on SO_2 emissions for a particular region of the country would likely result in an excess supply of title IV allowances and the potential for increased emissions in the area not subject to the more stringent emission cap. The potential for increased emissions exists in the entire country for the years prior to the proposed implementation deadline and would continue after implementation for any areas not affected by the proposed rule. These excess emissions could negatively affect air quality, disrupt allowance markets, and erode confidence in cap and trade programs.

In view of the significant reductions in SO_2 emissions under title IV of the CAA, the large investments in pollution controls that firms have made under title IV that enable companies to sell excess emissions reductions, and the potential for emissions increases, it became a priority to think of ways to preserve the environmental benefits achieved through title IV and maintain the integrity of the title IV market for SO_2 allowances.

In addition, EPA does not have authority to remove the statutory requirements of title IV and must work within the context of the existing CAA to further reduce emissions of SO_2 through a new rule. Title IV has successfully reduced emissions of SO_2 using the cap and trade approach, eliminating millions of tons of SO_2 from the environment. Building off this existing program to further improve air quality by requiring additional reductions of SO_2 emissions is appropriate.

The EPA has developed an approach to incorporate the title IV SO_2 market to ensure that the desired reductions under this rule are achieved in a manner consistent with the previously stated environmental goals. The following sections provide more detail on EPA's initial analysis of the interactions between the title IV Acid Rain program and this proposal outlines a solution for creating a rule that builds off of title IV.

Initial Analysis

Initial analytical work shows that a more stringent cap on SO_2 emissions in the eastern part of the country, that is separate from the title IV cap, would create an excess supply of title IV allowances nationwide as sources in that eastern region comply with a tighter requirement than title IV and no longer need as many title IV allowances. As a result of this excess supply, all title IV allowances would lose value. This impact on the title IV market results in (1) an incentive to use all banked title IV allowances prior to implementation of the rule as firms anticipate the value of allowances dropping essentially to zero and (2) emission increases outside the region after rule implementation because those sources would be able to obtain title IV allowances at essentially no cost.

b. Emissions Increases Prior to Implementation of the Proposed Rule

The EPA expects that the number of banked (*i.e.*, the retention of unused

[96] *http://www.rff.org/CFDOCS/disc_papers/PDF_files/9925.pdf*

allowances from one calendar year for use in a later calendar year) title IV allowances will be in the millions of tons at the end of 2009 in the absence of the rule. The actual number of allowances banked will depend upon future economic growth and the independent decisions of the sources between now and 2010, and EPA will continue to evaluate emissions trends and the bank prior to finalizing the rule. Should the rule not permit the use of banked title IV allowances in the program, the banked allowances would likely be expended during the years prior to implementation of the rule. This could cause over 1 million tons per year of additional SO_2 emissions, nationwide, that could be emitted above levels projected in the absence of a rule.

c. Consideration for Emissions Shifting Outside the Control Region

Title IV sources outside the more stringently regulated region would be able to obtain title IV allowances from sources affected by the rule at very low cost after the commencement of the program. The flow of inexpensive, abundant allowances out of an area with more stringent emission control requirements is referred to as "leakage" and would likely result in increased emissions outside the region. In essence, sources outside of the region would not face a binding title IV constraint on their emissions of SO_2 due to the potential availability of abundant allowances provided by sources inside of the control region. Though certain State and local requirements or physical constraints would mitigate the problem of emissions increases outside the region, meaningful increases would be a possibility. Emissions increases outside the region would worsen air quality in those areas and could potentially negate some of the reductions achieved in the region.

The potential for leakage is dependent upon the size of the region. The large eastern trading region proposed in today's rule—which is based upon addressing $PM_{2.5}$—is not likely to result in significant leakage because the region is large enough to take advantage of the physical limitations in the electricity grid that prevent large power movements from the East to the West (or vice versa) through the Western Interconnect.

d. Desired Outcomes in the Design of the Cap and Trade Rule

The proposed cap and trade program will be designed to meet three primary goals: (1) Achieving environmental goals; (2) preserving and potential strengthening of allowance trading markets; and (3) providing the flexibility to incorporate additional jurisdictions and types of sources in the future, while maintaining the integrity of the cap and allowance markets.

First and foremost, the proposed cap and trade program must be designed to improve air quality to protect the public's health and the environment. To accomplish this, the program must address the potential for emission leakage, require credible emission monitoring and reporting, and provide for source accountability.

Preservation of the benefit of the title IV allowance market (*i.e.*, a solution that would maintain or even increase the economic value of title IV allowances) would eliminate the incentive to increase emissions prior to the start of the program and ease the administrative transition. Incorporating title IV creates incentives for earlier reductions by title IV sources and may create incentives for title IV sources not included in the rule to maintain, or even reduce, emissions of SO_2 both before and after the rule goes into effect. In addition, it sends a clear signal to sources that have already made investments in pollution control equipment that the allowance market is sound and will continue to operate.

The proposed cap and trade solution must provide opportunities for incorporating additional sources (*e.g.*, non-title IV sources, other source categories) and States, during promulgation and in the future. Designing a cap and trade program that can include these additional sources creates the potential to achieve additional environmental benefit and/or reduce the program's total cost.

e. Discussion of Possible Solutions

The EPA explored several options for addressing the coordination of title IV and the proposed rule consistent with the objective of minimizing emissions increases and providing a mechanism of allocating allowances to sources lacking any title IV allocations. One option would establish a separate cap and trade program for SO_2 that would require the retirement of surplus title IV allowances for the rule (*i.e.*, the difference between total title IV allocations and the trading budget for a given State under the rule). Sources would have to comply with both programs independently, and States would have flexibility in allocating the newly created allowances to non-title IV sources. Although this option could be designed so as to maintain the value of title IV allowances once the new cap and trade program begins under the rule, thus minimizing leakage, it would not address banked title IV allowances accumulated before implementation of the program, resulting in possible emissions increases prior to rule implementation.

Another option would allow for conversion of title IV allowances into separate allowances under a new cap and trade program. This conversion would be applied at a specific ratio (*e.g.*, two-to-one) that yields the desired emission reductions, and could be applied to both banked and current title IV allowances. By complying with the rule and submitting more than one title IV allowance for every ton emitted, a source would be in compliance with both programs. New allowances could be created to give States flexibility with SO_2 allocations, but the conversion ratio would need to be adjusted to incorporate these new allowances. This solution presents some challenges, such as establishing the proper conversion ratio and the need to adjust the cap under the rule to account for the converted allowances. In addition, the uncertainty surrounding how many banked allowances would be converted poses challenges when designing the cap and trade rule.

f. Proposed Approach

A third option and the approach proposed here best addresses the three principles identified above. It would require sources to use title IV allowances directly for compliance with the rule in a way that maintains the downward trend in emissions throughout the country, preserves the existing SO_2 allowance market, and allows the inclusion of non-title IV sources, now and in the future.

Title IV sources in the region would be required to comply with the rule by using more than one title IV allowance for every ton emitted (*e.g.*, a two-to-one ratio). EPA would propose to amend the title IV rules in a future SNPR so that sources that comply with the rule would be deemed in compliance with title IV since by submitting allowances at a greater than one-to-one ratio, a source would be going beyond what title IV required. The requirement to submit more than one allowance for every ton emitted is, in effect, a reduction of the title IV cap. The specific ratio would be determined based on the amount of emissions to be allowed for the region. The ratio, in essence, would reflect the cap levels and determine the ultimate emissions in the region. Section VIII.B.3 below, discusses a methodology that could be used to provide allowances to EGUs that were not allocated allowances under title IV.

While EPA is not currently proposing to require sources other than EGUs to be part of the cap and trade program, EPA believes that this approach could also allow other sources to participate in the cap and trade program. States electing to include additional sources could develop mechanisms to provide them with access to allowances through auctions or direct allocations. (This is discussed in greater detail in section VIII.B.3.)

i. Using Pre-2010 Banked Title IV Allowances in Proposed SO_2 Cap and Trade Program

Under the proposed approach, title IV allowances could be banked before the 2010 implementation date for use in the new program. Pre-2010 title IV allowances banked prior to 2010 could be used at a one-to-one ratio for compliance at any time. This provides incentives to reduce emissions before the 2010 implementation date because sources would want to ease the transition to the more stringent caps in 2010 and thereafter. However, it should be noted that these allowances could then be used in later years, delaying the amount of time until the ultimate cap level is achieved.

ii. Proposed Ratios and the Phasing of the Caps

The proposed SO_2 program would allow: (1) Pre-2010 allowances to be used at a one-to-one ratio; (2) 2010 through 2014 allowances to be used at a two-to-one; and (3) 2015 and later allowances to be used at a three-to-one ratio. Since title IV allowances are already identified by serial numbers that indicate the year the allowance is first allowed to be used, it is possible to use different retirement ratios for allowances of different vintages. The progressively more stringent, phased-in nature of the rule will be reflected in the proposed cap and trade program by adjusting the ratio for retiring allowances in each phase. EPA developed these ratios to achieve the emissions reductions as described in section VI with careful consideration given to the title IV bank, State EGU budgets, and phasing in order to create ratios that are consistent with the objectives of the rule. The ratios, in effect, tighten the existing title IV cap.

States choosing to participate in the cap and trade program must require sources to submit title IV allowances at the ratios set in the model rule.

The EPA projects that using 2010 to 2014 vingtage title IV allowances at a ratio of two-to-one and post 2014 allowances at a ratio of three-to-one in the second phase will produce the desired emission reductions for SO_2. These ratios are projected to lead sources to bank roughly an additional 10.5 million allowances prior to 2010. Vintage year allowances 2009 and earlier are projected to be used starting in 2010 at an average rate of 1.3 million per year.

The value of title IV allowances is projected to increase to $400 during the first phase, and to fall to $330 during the second phase, according to EPA modeling. In other words, sources in the region would face a marginal cost of $805 per ton of emissions in the first phase at a two-to-one ratio and $989 in the second phase at a three-to-one ratio. The marginal cost numbers presented here are generated from EPA modeling of this rule, looking specifically at the interactions with title IV.

3. Allowance Allocations

a. Statewide Cap and Trade Budgets

Today's rule proposes statewide EGU SO_2 emission budgets (detailed in section VI) that States may allocate. Discretion in the allocation of this budget to title IV units (which constitute a majority of the EGUs) that already receive allowances under title IV is somewhat limited for States because the existing title IV SO_2 allocation provisions explicitly allocate allowances to specific units. Therefore, as a practical matter, States that wish to participate in an EPA-managed interstate trading program will not have as much flexibility in developing their SO_2 allocation methodology for title IV units that already receive allowances than they will with NO_X allocations.

b. Determination of SO_2 Allowance Allocations for EGUs Not Receiving Title IV Allowances

As discussed in section VI (Statewide Emissions Budgets), States will have the flexibility to address equity issues for newer units that do not receive title IV allowances. However, as mentioned above, because title IV allocates virtually all of the Acid Rain Program allowances directly to individual sources, any State electing to provide allowances to newer sources would have to develop a mechanism that creates an excess of allowances after the initial allocation. One potential remedy is a mechanism that creates a State-managed pool of allowances from EGUs within that State by either: (1) Requiring in-State EGUs that receive title IV allowances to surrender allowances at a rate tighter than today's rule retirement ratio and transferring this overage to the State (*e.g.*, an EGU would retire 2 allowances and surrender 1 allowance for every ton emitted); or, (2) tightening the retirement ratio for in-State EGUs that receive title IV allowances and providing for EPA to create new SO_2 allowances, the total being equal to or less than the overage, that are issued to the new sources (*e.g.*, an EGU would retire 3 allowances for every ton emitted and EPA would issue a new SO_2 allowance to the new source). EPA intends to assist States by providing a more detailed discussion of allocation alternatives in a future SNPR.

Should States decide to allocate allowances to these newer EGUs, States would be given latitude in determining how they would distribute them from the pool of allowances for EGUs that receive title IV allowances. States may choose to hold an allowance auction or distribute allowances directly to sources. Should a State decide to allocate allowances, it would have flexibility in selecting the method upon which the allocation share is determined. Common methods for allocating allowances include:

(1) Actual emissions (in tons) from the unit,

(2) Actual heat input (in mmBtu) of the unit, and

(3) Actual production output (in terms of electricity generation and/or steam energy) of the unit.

Each of these options has variations, including the use of allowance set-asides, and may be implemented with allocations performed on a permanent or an updating basis.

The details of specific allocation options will be presented in greater detail in the future SNPR.

C. Consideration and Aspects Unique to the NO_X Cap and Trade Program

1. NO_X Cap and Trade Program Overview

The NO_X cap and trade program would be substantially similar, in its basic requirements and procedures, to the SO_2 cap and trade program described above. However, some components of a proposed NO_X cap and trade program are unique to its implementation in the context of existing regional NO_X control programs. This section describes those unique components. Because the authority for the existing NO_X cap and trade programs exists at the State level and are not constrained by intricate title IV interactions, States may have more flexibility to revise their existing rules than they would have in complying with the proposed SO_2 program. Section VIII.D discusses elements of the cap and trade programs that are common to both the SO_2 and NO_X programs.

2. Interactions with the NO_X SIP Call Cap and Trade Program and the Title IV NO_X Program

This section discusses specific implementation issues related to transitioning from existing regional NO_X control programs to today's proposed NO_X cap and trade program.

a. Geographic Scope

States in the Proposed Region. Ideally, the NO_X and SO_2 cap and trade program regions would be identical. However, the geographic boundaries of the NO_X cap and trade program must be related to the contribution made by emissions sources to the interstate transport of NO_X as it affects non-attainment of $PM_{2.5}$ and ozone standards. While the $PM_{2.5}$ standard of most interest is annual, the ozone standard is an 8-hour duration with exceedances in the summer season. Therefore, EPA is proposing a NO_X trading region that applies to those States affected by the $PM_{2.5}$ finding; a region which encompasses virtually the same region as would be affected by the ozone findings with the exception of the State of Connecticut. Furthermore, EPA is proposing to allow the State of Connecticut, which is required to reduce only summertime NO_X emissions to address ozone under today's action, to participate in the EPA-managed NO_X cap and trade program on an annual basis. In addition, EPA proposes to allow other States currently participating in EPA-managed, ozone season, NO_X cap and trade programs to join the year-round NO_X cap and trade program on an annual basis. If States chose to participate on an annual basis, EPA will determine corresponding annual budgets.

States Outside the Proposed Region with Existing Regional NO_X Cap and Trade Programs. There are three States that participate in the existing regional NO_X trading market that would not be affected by today's proposed ozone or $PM_{2.5}$ rules: New Hampshire (as part of the OTC), and Massachusetts and Rhode Island (as part of the NO_X SIP Call). These States would be allowed and encouraged to voluntarily participate in the NO_X cap and trade program under today's rules in order to minimize administrative burden and simplify compliance for sources. Both the OTC and NO_X SIP Call are ozone season only compliance programs. Any States choosing to participate in an EPA-managed program proposed today, would be required to participate on an annual basis if they choose to participate in the proposed NO_X cap and trade program.

b. Seasonal-to-Annual Compliance Period

The NO_X SIP Call regulates NO_X emissions during an "ozone season" that lasts from May 1 through September 30. The proposed rule requires annual NO_X reductions. As explained in section VI, EPA analysis shows that under the proposed annual caps, EGUs in the NO_X SIP Call region would emit less during the ozone season than they were allowed to emit under the NO_X SIP Call.

c. Revision of Existing State NO_X SIP Call Rules

The EPA plans to design the model cap and trade rule in such a way that States that are part of the NO_X SIP Call will be able to modify their State rules to include the new provisions and new NO_X caps, and States that are not currently part of the NO_X SIP Call will be able to adopt the model rule language for the new program. Transition issues, such as new NO_X caps and applicability will be discussed thoroughly in the SNPR.

d. Retention of Existing Title IV NO_X Emission Rate Limits

Title IV requires coal-fired EGUs to meet average annual NO_X emission rates. These requirements would remain in effect after the 2010 compliance deadline for this proposed rule. EPA analysis shows that under the more stringent NO_X cap of today's rule, the title IV NO_X limits would not be binding for most units. Therefore, the limits would not interfere with the ability of the NO_X trading market to find the least-cost reductions. However, without a statutory change, the title IV NO_X program remains in effect and sources would have to continue to comply with its administrative requirements.

e. The NO_X Allowance Banking

The NO_X emission allowance trading market being administered by EPA for the NO_X SIP Call States has been active and we wish to make the transition to the NO_X program proposed today as simple as possible. For that reason, any entity holding existing NO_X allowances will be able to bank them and carry them forward into the new, proposed cap and trade program. While EPA believes it is important to provide this compliance flexibility for sources, it is unlikely that many sources will take advantage of this mechanism because the projected future value of NO_X allowances under the proposed cap and trade program is less than under the existing NO_X cap and trade programs.

3. NO_X Allocations

Within each State participating in the proposed NO_X cap and trade program, the statewide EGU budget (described in section VI of today's proposal) would form the basis for NO_X allocations. Unlike SO_2 allocations that are heavily dictated by the interaction between the proposed SO_2 cap and trade program and title IV, there are many allocation options that States could consider for distributing NO_X allowances.

There is a variety of allocation approaches that address equity issues and provide opportunities for States to encourage specific behaviors. This would include flexibility in how often the allocations are updated (*i.e.*, a one-time permanent allocation or one that is periodically updated) and the process metric upon which the allocation share is determined. As described below in section VIII.D.4, States participating in an EPA-managed program would be required to be consistent in the deadline for finalizing their source-by-source allocation.

The details of specific allocation options will be more fully developed and presented in detail in the future SNPR.

4. Joining Both SO_2 and NO_X Cap and Trade Programs for States Voluntarily Participating

The participation by States in both the EPA-managed NO_X cap and trade program and the EPA-managed SO_2 program offers administrative advantages to EPA and, we think, maximizes cost-effectiveness to the sources. We encourage each State to participate in both programs, and we think that, as a practical matter, many States will elect to do so.

We would like, in the SNPR, to propose to require that States that elect to participate in the EPA-managed NO_X cap and trade program be required to participate in the EPA-managed SO_2 program, and vice-versa. However, we are concerned that this requirement may be considered to intrude upon the prerogatives of the States in developing their SIPs.[97] We solicit comment on this question.

D. Cap and Trade Program Aspects That Are Common to Both the SO_2 and NO_X Programs

Sections VIII.B and VIII.C discussed key considerations that are unique to the proposed SO_2 and NO_X cap and trade programs, respectively. This section presents elements of a cap and trade program that must be a part of a

[97] *See Virginia* v. *EPA, 108 F.3d 1397 (D.C. Cir. 1997).*

State's rule—for both the SO_2 and NO_X programs—if it wishes to participate in the regional cap and trade program. As noted earlier, EPA intends to provide a detailed discussion and propose model rules in the future SNPR. Although EPA is not soliciting comment on the discussion in this section VIII, and instead will provide a full opportunity to comment on the SNPR, EPA recognizes that some may wish to comment on today's discussion. As such, commenters are encouraged to focus on the implications of addressing multiple environmental problems (*i.e.*, PM2.5 and ozone).

1. Applicability

Applicability, or the group of sources that the regulations will affect, must be similar from State-to-State to minimize confusion, administrative burdens, and emission leakage.

a. Core Applicability

As discussed in section VI, we have determined State EGU emission reduction requirements (which are sometimes referred to as "budgets") assuming reductions from large EGUs (*e.g.* boilers and turbines serving an electrical generator with a nameplate capacity exceeding 25MW and producing power for sale). States must include these core sources if they wish to participate in the regional cap and trade program. While States have discretion to achieve the required reduction levels by regulating other sources, EPA analysis identified EGUs as appropriate candidates for achieving the mandated reductions. If a State chooses to regulate other source categories, EPA is proposing that these source categories can be included in the cap and trade program only if EPA and the State agree that each source category can meet all of the requirements that are mandated for EGUs (*e.g.*, monitoring according to 40 CFR part 75 and the ability to clearly assign legal responsibility for compliance).

Once a unit is classified as an EGU for purposes of this rule, the unit will remain classified as an EGU regardless of any future modifications to the unit. If a unit serving a generator that initially does not qualify as an EGU (based on the nameplate capacity) is later modified to increase the capacity of the generator to the extent that the unit meets the definition of EGU, this unit shall be considered an EGU for purposes of this rule. This approach is proposed to prevent sources from derating units for the purpose of avoiding regulation.

2. Allowance Management System, Compliance, Penalties, and Banking

The allowance management system, compliance, penalties and banking are all components of the accounting system that enables the functioning of a cap and trade program. An accurate, efficient accounting system is critical to an emissions trading market. Transparency of the system, allowing all interested parties access to the information contained in the accounting system, increases the accountability for regulated sources and contributes to reduced transaction costs of transferring allowances by minimizing confusion and making allowance information readily available.

In order to guarantee the equitable treatment of all affected sources across the trading region, the elements included in this section need to be incorporated in the same manner in each State that participates in the cap and trade program.

a. Allowance Management

The EPA intends to propose a model cap and trade rule that will be reasonably consistent with the existing allowance tracking systems that are currently in use for the Acid Rain Program under title IV and the NO_X Budget Trading Program under the NO_X SIP Call. These two systems are called the Allowance Tracking System (ATS) and the NO_X Allowance Tracking System (NATS), respectively. Under the cap and trade rule, the SO_2 program and the NO_X program would remain separate trading programs maintained in ATS and NATS. Both ATS and NATS would remain as automated systems used to track SO_2 and NO_X allowances held by affected units under the cap and trade program, as well as those allowances held by other organizations or individuals. Specifically, ATS and NATS would track the allocation of all SO_2 and NO_X allowances, holdings of SO_2 and NO_X allowances in accounts, deduction of SO_2 and NO_X allowances for compliance purposes, and transfers between accounts. The primary role of ATS and NATS is to provide an efficient, automated means of monitoring compliance with the cap and trade programs. ATS and NATS also provide the allowance market with a record of ownership of allowances, dates of allowance transfers, buyer and seller information, and the serial numbers of allowances transferred.

b. Compliance

Compliance in the cap and trade program consists of the deduction of allowances from affected facilities' accounts to offset the quantity of emissions at the facilities for each compliance period. Currently under the Acid Rain and regional NO_X cap and trade programs, compliance is assessed at the unit level. Some flexibility is allowed in the NO_X program through the use of overdraft accounts. Both EPA and the regulated community find that, in practice, overdraft accounts and their use can be quite complicated and do not significantly reduce the burden of unit-level accounting. EPA is considering an approach that assesses compliance at the facility level in the proposed cap and trade program. More discussion of this option will be included in the future SNPR.

c. Penalties

The EPA plans to propose a system of automatic penalties should a facility not obtain sufficient NO_X or SO_2 allowances to cover emissions for the compliance period. In order to offset this deficiency in allowances, a facility must surrender allowances allocated for a future year equal in amount to the deficiency in allowances for the current compliance period. In addition, EPA will propose that an automatic penalty be imposed in addition to this offset in order to provide a strong incentive for facilities to hold sufficient allowances. The automatic penalty provisions will not limit the ability of the permitting authority or EPA to take enforcement action under State law or the CAA, but will establish for the regulated community the immediate, minimum economic consequences of noncompliance.

d. Banking

Banking is the retention of unused allowances from one calendar year for use in a later calendar year. Banking allows sources to make reductions beyond required levels and "bank" the unused allowances for use later. Generally speaking, banking has several advantages: it can encourage earlier or greater reductions than are required from sources, stimulate the market and encourage efficiency, and provide flexibility in achieving emissions reduction goals. On the other hand, it may result in banked allowances being used to allow emissions in a given year to exceed the cap and trade program budget. Banking of allowances from the Acid Rain and regional NO_X cap and trade programs into the proposed cap and trade program is discussed above in section VIII.B.2.f(i) for Acid Rain and above in section VIII.C.2.e. for the NO_X SIP Call.

Based on the experience of both the SO_2 and NO_X cap and trade programs, EPA plans to propose in the future SNPR that the banking of allowances after the start of the cap and trade program be allowed with no restrictions.

3. Accountability for Affected Sources

Key to the success of existing cap and trade programs and the integrity of the allowance trading markets has been clear accountability for unit emissions. This takes the form of affected units officially designating a specific person (and alternate) as responsible for the official certification of all allowance transfers and emissions monitoring and reporting as submitted to EPA in quarterly compliance reports. With each quarterly submission, this responsible party must certify that: the monitoring data were recorded in compliance with the monitoring and reporting requirements, including quality assurance testing and missing data procedures; and, the emission and operational reports are true, accurate, and complete.

The cap and trade program to be proposed in the future SNPR will include provisions to provide for the same strict standards for source accountability established in the Acid Rain Program and the NO_X SIP Call. This will include provisions for the establishment of an Authorized Account Representative. Adoption of these provisions will be required by all States that wish to participate in the cap and trade program.

4. Allowance Allocation Timing

The SNPR will propose requirements for when a State would finalize allowance allocations for each control period in the cap and trade program and submit them to EPA for inclusion into the ATS and NATS. The timing requirements ensure that all units would have equal and sufficient time to plan for compliance for each control period and equal time to trade allowances. The requirement would also contribute to the efficient administration of the trading program. By establishing this schedule at the outset of the cap and trade program, both the States and EPA would be able to develop internal procedures for effectively implementing the allowance provisions of the trading program. The timing requirements would ensure that EPA would be able to record in the ATS and NATS the allowance allocations for the budget units in all participating States at the same time for each control period.

5. Emissions Monitoring and Reporting

Monitoring and reporting of an affected source's emissions are integral parts of any cap and trade program. Consistent and accurate measurement of emissions ensures each allowance actually represents one ton of emissions and that one ton of reported emissions from one source is equivalent to one ton of reported emissions from another source. This establishes the integrity of the allowance and instills confidence in the market mechanisms which are designed to provide sources with flexibility in achieving compliance. Given the variability in the type, operation and fuel mix of sources in the cap and trade program, EPA believes that to ensure the needed accuracy and consistency, emissions must be monitored continuously. For many sources, this accuracy and consistency is achieved through the use of continuous emissions monitors (CEMS); however, alternative monitoring methodologies are appropriate for certain types of sources. The continuous emissions monitoring methods must also incorporate rigorous quality assurance procedures (*e.g.*, periodic testing to ensure continued accuracy of the measurement method). Additionally, in order to account for all emissions at all times, provisions for estimating emissions during times when monitors are unavailable because of planned and unplanned outages are also necessary. Part 75 of the Acid Rain regulations (40 CFR part 75) sets forth monitoring and reporting requirements for both SO_2 and NO_X mass emissions and includes the additional provisions necessary for a cap and trade program. Part 75 is used in both the Acid Rain and NO_X SIP Call programs.

In an effort to ensure program integrity, EPA proposes to require States to include year round part 75 monitoring and reporting for SO_2 and NO_X for all sources. Monitor certification deadlines and other details will be specified in the model cap and trade rule. The EPA believes that emissions will then be consistently and accurately monitored and reported from unit to unit and from State to State.

Part 75 also specifies reporting requirements. The EPA proposes to require year-round, quarterly reporting of emissions and monitoring data from each unit at each affected facility. The EPA proposes a single quarterly report. The single report will include hourly emissions information for both SO_2 and NO_X emissions on a quarterly basis in a format specified by the Agency. The reports must be in an electronic data reporting (EDR) format and be submitted to EPA electronically using EPA's Emissions Tracking System (ETS). This coordinated reporting requirement is necessary to ensure consistent review, checking, and posting of the emissions and monitoring data at all affected sources, which contributes to the integrity and efficacy of the trading program.

Many sources affected by this rulemaking are already meeting the requirements of part 75. Impacts on different types of sources will be discussed thoroughly in the SNPR.

E. Inter-Pollutant Trading

Cap and trade programs can incorporate mechanisms for interpollutant trading when more than one pollutant contributes to the same environmental problem. While the proposed cap and trade programs would control SO_2 to address $PM_{2.5}$ and NO_X for both $PM_{2.5}$ and ozone, EPA solicits comment on whether SO_2 allowances and NO_X allowances should be interchangeable, and if so, at what ratio should the allowances be interchangeable. The main advantage of inter-pollutant trading is that it presents regulated entities with more flexibility in meeting compliance, thus reducing the costs of compliance. If the relative air quality impact of the two pollutants on the environmental issue (*i.e.*, $PM_{2.5}$ or ozone)is known, then inter-pollutant trading set at this ratio will achieve the same total air quality impact. There are many technical difficulties involved with incorporating an effective inter-pollutant trading mechanism, and EPA solicits opinions on the feasibility of addressing these concerns:

(1) What should be the exchange rate (*i.e.*, the transfer ratio) for the two pollutants?

(2) How can this transfer ratio best reflect the goals of achieving $PM_{2.5}$ and ozone attainment in downwind States?

(3) How would inter-pollutant trading accommodate the different geographic regions covered for SO_2 and NO_X under the proposed rule?

IX. Air Quality Modeling of Emissions Reductions

A. Introduction

In this section, we describe the air quality modeling performed to determine the projected impacts on $PM_{2.5}$ and 8-hour ozone of the regional SO_2 and NO_X emissions reductions in today's proposal. The regional emissions reductions are associated with State emissions budgets in 2010 and 2015, as explained in section VI. The impacts of the regional reductions in 2010 and 2015 are determined by comparing air quality modeling results for each of these regional control scenarios to the modeling results for the corresponding 2010 and 2015 Base Case scenarios. A description of the 2010 and 2015 Base Cases is provided in section IV. Note that neither the Base Cases nor the regional control strategy scenarios include any of the local control measures discussed in section IV. Also note that the 2015 Base Case does not include any 2010 emissions reductions from the regional strategy.

The 2010 and 2015 regional strategy budgets cover emissions from the power generation sector in 29 eastern States plus the District of Columbia that contribute significantly to both $PM_{2.5}$ and ozone nonattainment in downwind States.[98] These annual SO_2 and NO_X budgets are provided in section VI.

As described in section VI, EPA modeled a two-phase cap and trade strategy for SO_2 and for NO_X using the IPM to assess the impacts of the budgets in today's proposal. For the purposes of air quality modeling, we used a scenario that assumes a 48-State SO_2 trading area and SO_2 allowances. Most of the SO_2 emissions reductions in this scenario occur in the 28-State and DC control region; there are only small changes in nearly States not affected by today's proposal.[99] We do not expect these latter changes to actually occur; but, because they are only small changes, the results of using this IPM scenario are expected to be very similar to the actual results of today's proposal. For NO_X, EPA modeled a NO_X trading scenario covering 31 States, DC, and the eastern half of Texas. The 31 States include Arkansas, Iowa, Louisiana, Minnesota, Missouri, and all other States to the east of these five States. Thus, the modeled strategy does not match the NO_X reductions required in today's proposal for Kansas and western Texas. In addition, the modeled strategy includes NO_X reductions in Maine, New Hampshire, Rhode Island, and Vermont which do not have any required reductions in today's proposal.

Phase 1 of the regional strategy is forecast to reduce total EGU SO_2 emissions in the 28-States plus DC by 40 percent in 2010. Phase 2 is forecast to provide a 44 percent reduction in EGU SO_2 emissions compared to the Base Case in 2015. When fully implemented, we expect today's proposed rule to result in more than a 70 percent reduction in EGU SO_2 emissions compared to current emissions levels. The net effect of the strategy on total SO_2 emissions in the 28-State plus DC region, considering all sectors of emissions, is a 27 percent reduction in 2010 and a 28 percent reduction in 2015. For NO_X, Phase 1 of the strategy is forecast to reduce EGU emissions by 44 percent and total emissions by 10 percent in the 28-States plus DC region in 2010. In Phase 2, EGU NO_X emissions are projected to decline by 53 percent in 2015. Total NO_X emissions are projected to be reduced by 14 percent in 2015. The percent change in emissions by State for SO_2 and NO_X in 2010 and 2015 for the regional strategy are provided in the Air Quality Modeling Technical Support Document (AQMTSD).[100]

B. The $PM_{2.5}$ Air Quality Modeling of the Proposed Regional SO_2 and NO_X Strategy

The PM modeling platform described in section IV was used by EPA to model the impacts of the proposed SO_2 and NO_X emissions reductions on annual average $PM_{2.5}$ concentrations. In brief, we ran the REMSAD model for the meteorological conditions in the year of 1996 using our nationwide modeling domain. Modeling for $PM_{2.5}$ was performed for both 2010 and 2015 to assess the expected effects of the proposed regional strategy in each of these years on projected $PM_{2.5}$ design value concentrations and nonattainment. The procedures used to project future $PM_{2.5}$ design values and nonattainment are described in section IV. The projected design values for each nonattainment county for the 2010 and 2015 scenarios are provided in the AQMTSD. The counties that are projected to be nonattainment for the $PM_{2.5}$ NAAQS are listed in Table IX–1 for the 2010 Base Case and the 2010 regional strategy scenario and in Table IX–2 for the 2015 Base Case and 2015 regional strategy scenario. The projected 2010 Base Case and control scenario $PM_{2.5}$ design values are provided in Table IX–3. The projected 2015 Base Case and control $PM_{2.5}$ design values are provided in Table IX–4. Concerning the future baseline concentrations, we expect improvement beyond 2015 based on the fact that the bank will be used up and further reductions are expected from the Heavy Duty Diesel Engines and Land-based Non-road Diesel Engines rules. Also, even those counties that remain nonattainment in 2015 after the controls in today's rule will benefit from air quality improvements and lower concentrations of fine particles as a result of the SO_2 and NO_X emissions reductions in this rule.

TABLE IX–1.—PROJECTED $PM_{2.5}$ NONATTAINMENT COUNTIES FOR 2010 BASE CASE AND REGIONAL STRATEGY SCENARIOS

State	2010 base case projected $PM_{2.5}$ nonattainment counties	2010 regional strategy case projected $PM_{2.5}$ nonattainment counties
AL	DeKalb, Jefferson, Montgomery, Russell, Talladaga	Jefferson, Russell, Talladaga.
CT	New Haven	None.
DC	Washington DC	None.
DE	New Castle	None.
GA	Clarke, Clayton, Cobb, DeKalb, Floyd, Fulton, Hall, Muscogee, Paulding, Richmond, Wilkinson.	Clarke, Clayton, Cobb, DeKalb, Floyd, Fulton, Muscogee, Wilkinson.
IL	Cook, Madison, St. Clair, Will	Cook, Madison, St. Clair.
IN	Clark, Marion	None.
KY	Fayette, Jefferson	None.
MD	Baltimore City	None.
MI	Wayne	Wayne.
MO	St. Louis	None.
NY	New York (Manhattan)	New York (Manhattan).
NC	Catawba, Davidson, Mecklenburg	None.

[98] In addition, summer season only EGU NO_X controls are proposed for Connecticut which significantly contributes to ozone, but not $PM_{2.5}$ nonattainment in other States.

[99] The modeled scenario reduces EGU emissions in the five New England States not covered by today's proposal by less than 3,000 tons per year. In the 15 States located to the west of the region covered by today's proposal, total EGU SO_2 emissions decline by 17 percent.

[100] "Air Quality Modeling Technical Support Document for the Proposed Interstate Air Quality Rule" (January 2004), can be obtained from the docket for today's proposed rule: OAR–2003–0053.

TABLE IX–1.—PROJECTED $PM_{2.5}$ NONATTAINMENT COUNTIES FOR 2010 BASE CASE AND REGIONAL STRATEGY SCENARIOS—Continued

State	2010 base case projected $PM_{2.5}$ nonattainment counties	2010 regional strategy case projected $PM_{2.5}$ nonattainment counties
OH	Butler, Cuyahoga, Franklin, Hamilton, Jefferson, Lawrence, Mahoning, Scioto, Stark, Summit, Trumbull.	Cuyahoga, Hamilton, Jefferson, Scioto, Stark.
PA	Allegheny, Berks, Lancaster, York	Allegheny.
SC	Greenville	None.
TN	Davidson, Hamilton, Knox, Roane, Sullivan	Knox.
WV	Brooke, Cabell, Hancock, Kanawha, Marshal, Wood	None.

TABLE IX–2.—PROJECTED $PM_{2.5}$ NONATTAINMENT COUNTIES FOR 2015 BASE CASE AND REGIONAL STRATEGY SCENARIOS

State	2015 base case projected $PM_{2.5}$ nonattainment counties	2015 regional strategy case projected $PM_{2.5}$ nonattainment counties
AL	Jefferson, Montgomery, Russell, Talladaga	Jefferson, Russel.
CT	New Haven	None.
GA	Clarke, Clayton, Cobb, DeKalb, Floyd, Fulton, Hall, Muscogee, Richmond, Wilkinson.	Clayton, DeKalb, Fulton.
IL	Cook, Madison, St. Clair	Cook.
IN	Clark, Marion	None.
KY	Jefferson	None.
MD	Baltimore City	None.
MI	Wayne	Wayne.
NY	New York County (Manhattan)	None.
OH	Butler, Cuyahoga, Franklin, Hamilton, Jefferson, Scioto, Stark, Summit	Cuyahoga, Hamilton, Jefferson, Scioto.
PA	Allegheny, York	Allegheny.
TN	Hamilton, Knox	Knox.
WV	Brooke, Cabell, Hancock, Kanawha, Wood	None.

TABLE IX–3.—PROJECTED $PM_{2.5}$ DESIGN VALUES FOR THE 2010 BASE CASE AND REGIONAL STRATEGY SCENARIOS

State	County	2010 base case	2010 regional control strategy
Alabama	DeKalb	15.22	13.92
Alabama	Jefferson	20.03	18.85
Alabama	Montgomery	15.69	14.60
Alabama	Russell	17.07	15.77
Alabama	Talladega	16.44	15.26
Connecticut	New Haven	15.43	14.50
Delaware	New Castle	15.43	14.12
District of Columbia	District of Columbia	15.48	13.70
Georgia	Clarke	17.04	15.56
Georgia	Clayton	17.73	16.43
Georgia	Cobb	16.80	15.56
Georgia	DeKalb	18.26	16.92
Georgia	Floyd	16.99	15.65
Georgia	Fulton	19.79	18.37
Georgia	Hall	15.62	14.24
Georgia	Muscogee	16.68	15.41
Georgia	Paulding	15.40	14.17
Georgia	Richmond	15.99	14.65
Georgia	Wilkinson	16.68	15.51
Illinois	Cook	17.90	16.90
Illinois	Madison	16.41	15.33
Illinois	St. Clair	16.31	15.11
Illinois	Will	15.21	14.25
Indiana	Clark	15.86	14.34
Indiana	Marion	15.89	14.39
Kentucky	Fayette	15.21	13.55
Kentucky	Jefferson	15.79	14.23
Maryland	Baltimore City	16.58	14.82
Michigan	Wayne	18.78	17.65
Missouri	St. Louis City	15.25	14.14
New York	New York	16.30	15.25
North Carolina	Catawba	15.26	13.87
North Carolina	Davidson	15.52	14.22

TABLE IX–3.—PROJECTED $PM_{2.5}$ DESIGN VALUES FOR THE 2010 BASE CASE AND REGIONAL STRATEGY SCENARIOS—Continued

State	County	2010 base case	2010 regional control strategy
North Carolina	Mecklenburg	15.18	13.92
Ohio	Butler	16.01	14.53
Ohio	Cuyahoga	19.13	17.68
Ohio	Franklin	16.69	15.04
Ohio	Hamilton	17.75	15.96
Ohio	Jefferson	18.04	16.06
Ohio	Lawrence	15.48	13.67
Ohio	Mahoning	15.39	13.76
Ohio	Scioto	18.40	16.33
Ohio	Stark	17.09	15.19
Ohio	Summit	16.35	14.71
Ohio	Trumbull	15.13	13.56
Pennsylvania	Allegheny	19.52	16.92
Pennsylvania	Berks	15.39	13.84
Pennsylvania	Lancaster	15.46	13.71
Pennsylvania	York	15.68	13.93
South Carolina	Greenville	15.06	13.75
Tennessee	Davidson	15.36	13.92
Tennessee	Hamilton	16.14	14.74
Tennessee	Knox	18.36	16.60
Tennessee	Roane	15.18	13.69
Tennessee	Sullivan	15.24	13.77
West Virginia	Brooke	16.60	14.77
West Virginia	Cabell	16.39	14.41
West Virginia	Hancock	16.69	14.85
West Virginia	Kanawha	17.11	14.81
West Virginia	Marshall	15.53	13.25
West Virginia	Wood	16.30	14.15

TABLE IX–4.—PROJECTED $PM_{2.5}$ DESIGN VALUES FOR THE 2015 BASE CASE AND REGIONAL STRATEGY SCENARIOS

State	County	2015 base case	2015 regional control strategy
Alabama	Jefferson	19.57	18.11
Alabama	Montgomery	15.35	14.05
Alabama	Russell	16.68	15.05
Alabama	Talladega	15.97	14.57
Connecticut	New Haven	15.13	14.13
Georgia	Clarke	16.46	14.58
Georgia	Clayton	17.26	15.49
Georgia	Cobb	16.28	14.37
Georgia	DeKalb	17.93	16.22
Georgia	Floyd	16.51	14.71
Georgia	Fulton	19.44	17.62
Georgia	Hall	15.05	13.16
Georgia	Muscogee	16.31	14.71
Georgia	Richmond	15.51	13.82
Georgia	Wilkinson	16.40	14.88
Illinois	Cook	17.52	16.40
Illinois	Madison	16.03	14.88
Illinois	St. Clair	15.91	14.67
Indiana	Clark	15.40	13.69
Indiana	Marion	15.31	13.79
Kentucky	Jefferson	15.32	13.57
Maryland	Baltimore City	16.11	14.20
Michigan	Wayne	18.28	17.06
New York	New York (Manhattan)	15.82	14.69
Ohio	Butler	15.39	13.77
Ohio	Cuyahoga	18.58	17.05
Ohio	Franklin	16.18	14.46
Ohio	Hamilton	17.07	15.15
Ohio	Jefferson	17.49	15.51
Ohio	Scioto	17.62	15.49
Ohio	Stark	16.42	14.52
Ohio	Summit	15.78	14.14
Pennsylvania	Allegheny	18.64	16.09

TABLE IX–4.—PROJECTED $PM_{2.5}$ DESIGN VALUES FOR THE 2015 BASE CASE AND REGIONAL STRATEGY SCENARIOS—Continued

State	County	2015 base case	2015 regional control strategy
Pennsylvania	York	15.13	13.26
Tennessee	Hamilton	15.63	13.91
Tennessee	Knox	17.73	15.59
West Virginia	Brooke	16.10	14.26
West Virginia	Cabell	15.70	13.71
West Virginia	Hancock	16.18	14.33
West Virginia	Kanawha	16.45	14.10
West Virginia	Wood	15.58	13.49

The results of the air quality modeling indicate that 61 counties in the East are expected to be nonattainment for $PM_{2.5}$ in the 2010 Base Case. Of these 61 counties, 38 are projected to come into attainment in 2010 following the SO_2 and NO_X emissions reductions resulting from the regional controls in today's proposal. The 23 counties projected to remain nonattainment after the application of the regional strategy are expected to experience a sizeable reduction in $PM_{2.5}$ from this strategy, which will bring them closer to attainment. Specifically, the average reduction in these 23 residual 2010 nonattainment counties is 1.50 $\mu g/m^3$ with a range of 0.93 to 2.60 $\mu g/m^3$.

In 2015, the SO_2 and NO_X reductions in today's proposal are expected to reduce the number of $PM_{2.5}$ nonattainment counties in the East from 41 to 13. The regional strategy is predicted to provide large reductions in $PM_{2.5}$ in those 13 residual nonattainment counties. Specifically, the average reduction in these 13 residual 2015 nonattainment counties is 1.70 $\mu g/m^3$ with a range of 1.00 to 2.54 $\mu g/m^3$.

Thus, the SO_2 and NO_X emissions reductions which will result from today's proposal will greatly reduce the extent of $PM_{2.5}$ nonattainment by 2010 and beyond. These emissions reductions are expected to substantially reduce the number of $PM_{2.5}$ nonattainment counties in the East and make attainment easier for those counties that remain nonattainment by substantially lowering $PM_{2.5}$ concentrations in these residual nonattainment counties.

C. Ozone Air Quality Modeling of the Regional NO_X Strategy

The EPA used the ozone modeling platform described in section IV to model the impacts of the proposed EGU NO_X controls on 8-hour ozone concentrations. In brief, we ran the CAMx model for the meteorological conditions in each of the three 1995 ozone episodes using the Eastern U.S. modeling domain. Ozone modeling was performed for both 2010 and 2015 to assess the projected effects of the regional strategy in each of these years on projected 8-hour ozone nonattainment.

The results of the regional strategy ozone modeling are expressed in terms of the expected reduction in projected 8-hour design value concentrations and the implications for future nonattainment. The procedures used to project future 8-hour ozone design values and nonattainment are described in section IV. The projected design values and exceedance counts for each nonattainment county for the 2010 and 2015 scenarios are provided in the AQMTSD. The counties that are projected to be nonattainment for the 8-hour ozone NAAQS are listed in Table IX–5 for the 2010 Base Case and the 2010 regional strategy scenario and in Table IX–6 for the 2015 Base Case and 2015 regional strategy scenario. The projected 2010 Base Case and control scenario 8-hour ozone design values are provided in Table IX–7. The projected 2015 Base and control 8-hour ozone design values are provided in Table IX–8.

TABLE IX–5.—PROJECTED 8-HOUR OZONE NONATTAINMENT COUNTIES FOR 2010 BASE CASE AND REGIONAL STRATEGY SCENARIOS

State	2010 base case projected 8-hour ozone nonattainment counties	2010 regional strategy case projected 8-hour ozone non-attainment counties
AR	Crittenden	Crittenden.
CT	Fairfield, Middlesex, New Haven	Fairfield, Middlesex, New Haven.
DC	Washington, DC	Washington, DC.
DE	New Castle	New Castle.
GA	Fulton	Fulton.
IL	None	None.
IN	Lake	Lake.
MD	Anne Arundel, Baltimore, Cecil, Harford, Kent, Prince Georges.	Anne Arundel, Baltimore, Cecil, Harford, Kent, Prince Georges.
MI	None	None.
NJ	Bergen, Camden, Cumberland, Gloucester, Hudson, Hunterdon, Mercer, Middlesex, Monmouth, Morris, Ocean.	Bergen, Camden, Cumberland, Gloucester, Hunterdon, Mercer, Middlesex, Monmouth, Morris, Ocean.
NY	Erie, Putnam, Richmond, Suffolk, Westchester	Erie, Putnam, Richmond, Suffolk, Westchester.
NC	Mecklenburg	Mecklenburg.
OH	Geauga, Summit	Geauga.
PA	Allegheny, Bucks, Delaware, Montgomery, Philadelphia	Bucks, Delaware, Montgomery, Philadelphia.
RI	Kent	Kent.
TX	Denton, Harris, Tarrant	Denton, Harris, Tarrant.
VA	Arlington, Fairfax	Arlington, Fairfax.

TABLE IX–5.—PROJECTED 8-HOUR OZONE NONATTAINMENT COUNTIES FOR 2010 BASE CASE AND REGIONAL STRATEGY SCENARIOS—Continued

State	2010 base case projected 8-hour ozone nonattainment counties	2010 regional strategy case projected 8-hour ozone nonattainment counties
WI	Kenosha, Racine, Sheboygan	Kenosha, Racine, Sheboygan.

TABLE IX–6.—PROJECTED 8-HOUR OZONE NONATTAINMENT COUNTIES FOR 2015 BASE CASE AND REGIONAL STRATEGY SCENARIOS

State	2015 base case projected 8-hour ozone nonattainment counties	2015 regional strategy case projected 8-hour ozone nonattainment counties
AR	Crittenden	None.
CT	Fairfield, Middlesex, New Haven	Fairfield, Middlesex, New Haven.
DC	Washington, DC	Washington, DC.
DE	None	None.
GA	None	None.
IL	Cook	None.
IN	Lake	Lake.
MD	Anne Arundel, Cecil, Harford	Anne Arundel, Cecil, Harford.
MI	Macomb	None.
NJ	Bergen, Camden, Gloucester, Hunterdon, Mercer, Middlesex, Monmouth, Morris, Ocean.	Bergen, Camden, Gloucester, Hunterdon, Mercer, Middlesex, Monmouth, Ocean.
NY	Erie, Richmond, Suffolk, Westchester	Erie, Richmond, Suffolk, Westchester.
NC	None	None.
OH	Geauga	None.
PA	Bucks, Montgomery, Philadelphia	Bucks, Montgomery, Philadelphia.
RI	Kent	None.
TX	Harris	Harris.
VA	Arlington, Fairfax	Arlington.
WI	Kenosha, Sheboygan	Kenosha.

TABLE IX–7.—PROJECTED 8-HOUR OZONE DESIGN VALUES FOR THE 2010 BASE CASE AND REGIONAL STRATEGY SCENARIOS

State	County	2010 base case	2010 regional control strategy
Arkansas	Crittenden	86	86
Connecticut	Fairfield	94	94
Connecticut	Middlesex	91	91
Connecticut	New Haven	92	92
District of Columbia	District of Columbia	88	88
Delaware	New Castle	87	86
Georgia	Fulton	86	85
Indiana	Lake	87	86
Maryland	Anne Arundel	91	91
Maryland	Baltimore	85	85
Maryland	Cecil	90	90
Maryland	Harford	93	93
Maryland	Kent	89	88
Maryland	Prince Georges	86	85
New Jersey	Bergen	88	87
New Jersey	Camden	93	92
New Jersey	Cumberland	86	85
New Jersey	Gloucester	95	95
New Jersey	Hudson	85	84
New Jersey	Hunterdon	89	89
New Jersey	Mercer	98	98
New Jersey	Middlesex	95	95
New Jersey	Monmouth	89	89
New Jersey	Morris	88	87
New Jersey	Ocean	105	104
New York	Erie	90	89
New York	Putnam	85	85
New York	Richmond	90	89
New York	Suffolk	90	90
New York	Westchester	86	85
North Carolina	Mecklenburg	85	86
Ohio	Geauga	88	88
Ohio	Summit	85	84

TABLE IX–7.—PROJECTED 8-HOUR OZONE DESIGN VALUES FOR THE 2010 BASE CASE AND REGIONAL STRATEGY SCENARIOS—Continued

State	County	2010 base case	2010 regional control strategy
Pennsylvania	Allegheny	85	84
Pennsylvania	Bucks	97	97
Pennsylvania	Delaware	87	86
Pennsylvania	Montgomery	90	89
Pennsylvania	Philadelphia	92	92
Rhode Island	Kent	89	88
Texas	Denton	87	87
Texas	Harris	100	100
Texas	Tarrant	88	87
Virginia	Arlington	88	88
Virginia	Fairfax	87	87
Wisconsin	Kenosha	94	93
Wisconsin	Racine	86	85
Wisconsin	Sheboygan	90	89

TABLE IX–8.—PROJECTED 8-HOUR OZONE DESIGN VALUES FOR THE 2015 BASE CASE AND REGIONAL STRATEGY SCENARIOS

State	County	2015 base case	2015 regional control strategy
Arkansas	Crittenden	85	83
Connecticut	Fairfield	94	93
Connecticut	Middlesex	89	88
Connecticut	New Haven	90	89
District of Columbia	District of Columbia	86	85
Illinois	Cook	85	84
Indiana	Lake	87	86
Maryland	Anne Arundel	87	86
Maryland	Cecil	86	85
Maryland	Harford	89	88
Michigan	Macomb	86	84
New Jersey	Bergen	87	86
New Jersey	Camden	91	90
New Jersey	Gloucester	93	92
New Jersey	Hunterdon	87	86
New Jersey	Mercer	96	95
New Jersey	Middlesex	92	92
New Jersey	Monmouth	87	86
New Jersey	Morris	85	83
New Jersey	Ocean	102	101
New York	Erie	88	86
New York	Richmond	87	87
New York	Suffolk	89	89
New York	Westchester	86	85
Ohio	Geauga	85	83
Pennsylvania	Bucks	95	94
Pennsylvania	Montgomery	89	88
Pennsylvania	Philadelphia	91	90
Rhode Island	Kent	85	84
Texas	Harris	99	98
Virginia	Arlington	87	86
Virginia	Fairfax	85	84
Wisconsin	Kenosha	93	91
Wisconsin	Sheboygan	86	84

In the 2010 Base Case (*i.e.*, without the emissions reductions called for in today's proposal), 47 counties in the East are forecast to be nonattainment for ozone. With the implementation of the proposed regional NO_X strategy, three of the 47 2010 Base Case nonattainment counties are forecast to come into attainment. Of the 44 counties that are projected to remain nonattainment in 2010 after the regional controls, 12 are projected to be within 2 ppb of attainment (*i.e.*, counties that have design values of 85 or 86 ppb).

In 2015, the number of nonattainment counties is expected to decline from 34 counties in the Base Case to 26 counties after the NO_X emissions reductions in today's proposal. The proposed regional NO_X strategy is projected to reduce nonattainment ozone design values in the East by 1 to 2 ppb in all but three of the 34 2015 Base Case nonattainment counties. Of the 26 counties that are forecast to remain nonattainment in the control case, ten are projected to be within 2 ppb of attainment. Thus, our modeling indicates that by 2010 and 2015 the NO_X controls in today's proposal will reduce ozone concentrations throughout the East and help bring areas into attainment with the 8-hour ozone NAAQS.

X. Benefits of Emissions Reductions in Addition to the PM and Ozone NAAQS

This proposed action will result in benefits in addition to the enumerated human health and welfare benefits resulting from reductions in ambient levels of PM and ozone. These other benefits occur both directly, from the reductions in NO_X and SO_2, and indirectly, through reductions in co-pollutants, such as mercury. For example, reductions in emissions of NO_X and SO_2 will contribute to substantial visibility improvements in many parts of the eastern U.S. where people live, work, and recreate, including mandatory Federal Class I areas such as the Great Smoky Mountains. Reductions in NO_X and SO_2 emissions from affected sources will also reduce acidification and eutrophication of water bodies. The potential for reductions in nitrate contamination of drinking water is another possible benefit of the rule. This proposal will also reduce acid and particulate deposition that damages cultural monuments and other materials. Reduced mercury emissions will lessen mercury contamination in lakes that can potentially reduce both human and wildlife exposure through consumption of contaminated fish. In contrast to the benefits discussed, it is also possible that this proposal will lessen the benefits of passive fertilization for forest and terrestrial ecosystems where nutrients are a limiting factor and for some croplands.

This rule will improve visibility in the transport region. Visibility impairment is widespread and expected to continue (67 FR 68251, November 8, 2002) and this proposed rule will help to improve visibility. We provide a limited assessment of the economic value of expected improvements in visibility at some Federal Class I areas in section XI.

The following section presents information on three categories of public welfare and environmental impacts related to reductions in emissions from affected sources: reduced acid deposition, reduced eutrophication of water bodies, and reduced human health and welfare effects due to deposition of mercury. A more thorough discussion of these effects is provided in "Benefits of the Proposed Interstate Air Quality Rule (January 2004)."

A. Atmospheric Deposition of Sulfur and Nitrogen—Impacts on Aquatic, Forest, and Coastal Ecosystems

Atmospheric deposition of sulfur and nitrogen, more commonly known as acid rain, occurs when emissions of SO_2 and NO_X react in the atmosphere (with water, oxygen, and oxidants) to form various acidic compounds. These acidic compounds fall to earth in either a wet form (rain, snow, and fog) or a dry form (gases and particles). Prevailing winds can transport acidic compounds hundreds of miles, often across State and national borders. Acidic compounds (including small particles such as sulfates and nitrates) cause many negative environmental effects, including acidifying lakes and streams, harming sensitive forests, and harming sensitive coastal ecosystems.

1. Acid Deposition and Acidification of Lakes and Streams

Acid deposition causes acidification of lakes and streams. The effect of atmospheric deposition of acids on freshwater and forest ecosystems depends largely upon the ecosystem's ability to neutralize the acid. Acid Neutralizing Capacity (ANC), a key indicator of the ability of the water and watershed soil to neutralize the acid deposition it receives, depends largely on the watershed's physical characteristics: geology, soils, and size. Waters that are sensitive to acidification tend to be located in small watersheds that have few alkaline minerals and shallow soils. Conversely, watersheds that contain alkaline minerals, such as limestone, tend to have waters with a high ANC. Areas especially sensitive to acidification include portions of the Northeast (particularly the Adirondack and Catskill Mountains, portions of New England, and streams in the mid-Appalachian highlands) and Southeastern streams.

Quantitative impacts of this proposal on acidification of water bodies have been assessed. Modeling for this proposed rule indicates lakes in the Northeast and Adirondack Mountains would improve in acid buffering capacity. Specifically, no lakes in the Andirondack Mountains are projected to be categorized as chronically acidic in 2030 as a result of this proposal. In contrast, twelve percent of these lakes are projected to be chronically acidic without the emissions reductions envisioned in this proposal. For Northeast lakes in general, 6 percent of the lakes are anticipated to be chronically acidic before implementation of this proposal. The IAQR is expected to decrease the percentage of chronically acidic lakes in the Northeast to 1 percent.

2. Acid Deposition and Forest Ecosystem Impacts

Current understanding of the effects of acid deposition on forest ecosystems focuses on the effects of ecological processes affecting plant uptake, retention, and cycling of nutrients within forest ecosystems. Research results from the 1990s indicate documented decreases in base cations (calcium, magnesium, potassium, and others) from soils in the northeastern and southeastern United States are at least partially attributable to acid deposition. Losses of calcium from forest soils and forested watersheds have now been documented as a sensitive early indicator of soil response to acid deposition for a wide range of forest soils in the United States.

Although sulfate is the primary cause of base cation leaching, nitrate is a significant contributor in watersheds that are nearly nitrogen saturated. Base cation depletion is a cause for concern because of the role these ions play in surface water acid neutralization and their importance as essential nutrients for tree growth (calcium, magnesium and potassium).

In red spruce stands, a clear link exists between acid deposition, calcium supply, and sensitivity to abiotic stress. Red spruce uptake and retention of calcium is impacted by acid deposition in two main ways: leaching of important stores of calcium from needles and decreased root uptake of calcium due to calcium depletion from the soil and aluminum mobilization. These changes increase the sensitivity of red spruce to winter injuries under normal winter conditions in the Northeast, result in the loss of needles, slow tree growth, and impair the overall health and productivity of forest ecosystems in many areas of the eastern United States. In addition, recent studies of sugar maple decline in the Northeast link low base cation availability, high levels of aluminum and manganese in the soil, and increased levels of tree mortality due to native defoliating insects. This proposal will improve acid deposition in the transport region, and is likely to have positive effects on the health and productivity of forest systems in the region.

3. Coastal Ecosystems

Since 1990, a large amount of research has been conducted on the impact of nitrogen deposition to coastal waters.

Nitrogen is often the limiting nutrient in coastal ecosystems. Increasing the levels of nitrogen in coastal waters can cause significant changes to those ecosystems. In recent decades, human activities have greatly accelerated nitrogen nutrient inputs, causing excessive growth of algae and leading to degraded water quality and associated impairments of estuarine and coastal resources for human uses.

It is now known that nitrogen deposition is a significant source of nitrogen to many estuaries. The amount of nitrogen entering estuaries due to atmospheric deposition varies widely, depending on the size and location of the estuarine watershed and other sources of nitrogen in the watershed. There are a handful of estuaries where atmospheric deposition of nitrogen contributes well over 40 percent of the total nitrogen load; however, in most estuaries for which estimates exist, the contribution from atmospheric deposition ranges from 15 to 30 percent. The area with the highest deposition rates stretches from Massachusetts to the Chesapeake Bay and along the central Gulf of Mexico coast.

In 1999, National Oceanic and Atmospheric Administration (NOAA) published the results of a 5-year national assessment of the severity and extent of estuarine eutrophication. An estuary is defined as the inland arm of the sea that meets the mouth of a river. The 138 estuaries characterized in the study represent more than 90 percent of total estuarine water surface area and the total number of U.S. estuaries. The study found that estuaries with moderate to high eutrophication conditions represented 65 percent of the estuarine surface area.

Eutrophication is of particular concern in coastal areas with poor or stratified circulation patterns, such as the Chesapeake Bay, Long Island Sound, and the Gulf of Mexico. In such areas, the "overproduced" algae tends to sink to the bottom and decay, using all or most of the available oxygen and thereby reducing or eliminating populations of bottom-feeder fish and shellfish, distorting the normal population balance between different aquatic organisms, and in extreme cases causing dramatic fish kills. Severe and persistent eutrophication often directly impacts human activities. For example, fishery resource losses can be caused directly by fish kills associated with low dissolved oxygen and toxic blooms. Declines in tourism occur when low dissolved oxygen causes noxious smells and floating mats of algal blooms create unfavorable aesthetic conditions. Risks to human health increase when the toxins from algal blooms accumulate in edible fish and shellfish, and when toxins become airborne, causing respiratory problems due to inhalation. According to the NOAA report, more than half of the nation's estuaries have moderate to high expressions of at least one of these symptoms—an indication that eutrophication is well developed in more than half of U.S. estuaries.

This proposal is anticipated to reduce nitrogen deposition in the IAQR region. Thus, reductions in the levels of nitrogen deposition will have a positive impact upon current eutrophic conditions in estuaries and coastal areas in the region.

B. Human Health and Welfare Effects Due to Deposition of Mercury

Mercury emitted from utilities and other natural and man-made sources is carried by winds through the air and eventually is deposited to water and land. In water, Hg is transformed to methylmercury through biological processes. Methylmercury, a highly toxic form of Hg, is the form of Hg of greatest concern for the purpose of this rulemaking. Once Hg has been transformed into methylmercury, it can be ingested by the lower trophic level organisms where it can bioaccumulate in fish tissue (*i.e.*, concentrations in predatory fish build up over the fish's entire lifetime, accumulating in the fish tissue as predatory fish consume other species in the food chain). Thus, fish and wildlife at the top of the food chain can have Hg concentrations that are higher than the lower species, and they can have concentrations of Hg that are higher than the concentration found in the water body itself. Therefore, the most common form of exposure to Hg for humans and wildlife is through the consumption of contaminated predatory fish, such as: commercially consumed tuna, shark, or other saltwater fish species and recreationally caught bass, perch, walleye or other freshwater fish species. When humans consume fish contaminated with methylmercury, the ingested methylmercury is almost completely absorbed into the blood and distributed to all tissues (including the brain); it also readily passes through the placenta to the fetus and fetal brain.

Based on the findings of the National Research Council, EPA has concluded that benefits of Hg reductions would be most apparent at the human consumption stage, as consumption of fish is the major source of exposure to methylmercury. At lower levels, documented Hg exposure effects may include more subtle, yet potentially important, neurodevelopmental effects. Some subpopulations in the U.S., such as: Native Americans, Southeast Asian Americans, and lower income subsistence fishers, may rely on fish as a primary source of nutrition and/or for cultural practices. Therefore, they consume larger amounts of fish than the general population and may be at a greater risk to the adverse health effects from Hg due to increased exposure. In pregnant women, methylmercury can be passed on to the developing fetus, and at sufficient exposure may lead to a number of neurological disorders in children. Thus, children who are exposed to low concentrations of methylmercury prenatally may be at increased risk of poor performance on neurobehavioral tests, such as those measuring attention, fine motor function, language skills, visual-spatial abilities (like drawing), and verbal memory. The effects from prenatal exposure can occur even at doses that do not result in effects in the mother. Mercury may also affect young children who consume fish contaminated with Hg. Consumption by children may lead to neurological disorders and developmental problems, which may lead to later economic consequences.

In response to potential risks of consuming fish containing elevated concentrations of Hg, EPA and FDA have issued fish consumption advisories which provide recommended limits on consumption of certain fish species for different populations. EPA and FDA are currently developing a joint advisory that has been released in draft form. This newest draft FDA–EPA fish advisory recommends that women and young children reduce the risks of Hg consumption in their diet by moderating their fish consumption, diversifying the types of fish they consume, and by checking any local advisories that may exist for local rivers and streams. This collaborative FDA–EPA effort will greatly assist in educating the most susceptible populations. Additionally, the reductions of Hg from this regulation may potentially lead to fewer fish consumption advisories, which will benefit the fishing community.

We are unable to quantify changes in the levels of methylmercury in fish associated with reductions in mercury emissions for this proposal. While it is beneficial to society to reduce mercury, we are unable to quantify and provide a monetized estimate of benefits at this time due to gaps in available information on emissions, fate and transport, human exposure, and health impact models. However, this proposal is anticipated to decrease annual EGU mercury emissions by 10.6 tons in 2010 or approximately 23.5 percent, by 11.8 tons in 2015 or 26.3 percent, and by

14.3 tons or 32 percent in 2020. Emission reduction percentage decreases are based upon expected mercury emissions changes from fossil-fired EGUs larger than 25 megawatt capacity.

XI. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), the Agency must determine whether a regulatory action is "significant" and therefore subject to Office of Management and Budget (OMB) review and the requirements of the Executive Order. The Order defines "significant regulatory action" as one that is likely to result in a rule that may:

1. Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or Tribal governments or communities;
2. Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;
3. Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or
4. Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

In view of its important policy implications and potential effect on the economy of over $100 million, this action has been judged to be an economically "significant regulatory action" within the meaning of the Executive Order. As a result, today's proposal was submitted to OMB for review, and EPA has prepared documents entitled "Benefits of the Proposed Interstate Air Quality Rule" (January 2004), "Economic and Energy Impact of the Proposed Interstate Air Quality Rule" (January 2004), and other related technical support documents collectively referred to here as the "economic analyses."

1. Summary of Economic Analyses

The economic analyses provide several important analyses of impacts on public welfare. These include an analysis of the social benefits, social costs, and net benefits of the regulatory scenario. The economic analyses also address issues involving small business impacts, unfunded mandates (including impacts for Tribal governments), environmental justice, children's health, energy impacts, and requirements of the Paperwork Reduction Act (PRA). Many of the analyses summarized below are preliminary. The EPA intends to update these analyses as part of the SNPR.

a. Benefit-Cost Analysis

The benefit-cost analysis concludes that substantial net economic benefits to society are likely to be achieved as a result of the reduction in emissions occurring as a result of this rulemaking. The results detailed below show that this rule would be highly beneficial to society, with annual net benefits in 2010 of approximately $55 billion, ($58 billion benefits compared to social cost of approximately $3 billion) and net benefits in 2015 of $80 billion ($84 benefits compared to social costs of $4 billion). All amounts are reflected in 1999$. As discussed in section IX, we did not complete air quality modeling that precisely matches the IAQR region. We anticipate that any differences in estimates due to the modeling region analyzed should be small.

i. Control Scenario

Today's proposed rulemaking sets forth requirements for States to eliminate their significant contribution to down-wind State's nonattainment of the ozone and PM2.5 NAAQS. In order to reduce this significant contribution, EPA is proposing to require that certain States reduce their emissions of SO_2 and NO_X. Those quantities were derived by calculating the amount of emissions of SO_2 and NO_X that EPA believes can be controlled from large EGUs in a highly cost-effective manner. For a more complete description of the reduction requirements and how they were calculated, see section VI of today's rulemaking.

While the emission reduction requirements were developed assuming highly cost-effective controls on EGUs, States are free to obtain the emissions reductions from other source categories. For purposes of analyzing the impacts of the rule, EPA is assuming the application of the controls that it has identified to be highly cost effective on all EGUs in the transport region.

ii. Cost Analysis and Economic Impacts

For purposes of today's proposal, EPA analyzed the costs using the IPM. The IPM is a model that EPA has used to analyze the impacts of regulations on the power sector. A description of the methodology used to model the costs and the results can be found in section VI. More details can be found in "Economic and Energy Impact of the Proposed Interstate Air Quality Rule" (January 2004).

iii. Human Health and Welfare Benefit Analysis

Our analysis of the health and welfare benefits anticipated from this proposed rule are presented in this section. Briefly, the analysis projects major benefits from implementation of the rule in 2010 and 2015. As described below, thousands of deaths and other serious health effects would be prevented. We are able to monetize annual benefits of approximately $58 billion in 2010 and $84 billion in 2015 (1999$) of those benefits.

Table XI–1 presents the primary estimates of reduced incidence of PM and ozone related health effects for the years 2010 and 2015 for the regulatory control strategy. In interpreting the results, it is important to keep in mind the limited set of effects we are able to monetize. Specifically, the table lists the PM and ozone related benefits associated with the reduction of ambient PM and ozone levels. These benefits are substantial both in incidence and dollar value. In 2010, we estimate that there will be approximately 9,600 fewer premature deaths annually associated with PM2.5, and the rule will result in 5,200 fewer cases of chronic bronchitis, 13,000 fewer non-fatal heart attacks, 8,900 fewer hospitalizations (for respiratory and cardiovascular disease combined); and result in significant reductions in days of restricted activity due to respiratory illness (with an estimate of 6.4 million fewer cases). We also estimate substantial health improvements for children from reduced upper and lower respiratory illness, acute bronchitis, and asthma attacks. Ozone health related benefits are expected to occur during the summer ozone season (usually ranging from May to September in the Eastern U.S.). Based upon modeling for 2010, ozone-related health benefits are expected to include 1,000 fewer hospital admissions for respiratory illnesses, 120 emergency room admissions for asthma, 280,000 fewer days with restricted activity levels, and 180,000 fewer days where children are absent from school due to illnesses. While we did not include separate estimates of the number of premature deaths that would be avoided due to reductions in ozone levels, recent evidence has been found linking short-term ozone exposures with premature mortality independent of PM exposures. Recent reports by Thurston and Ito (2001) and the World Health Organization (WHO) support an independent ozone mortality impact, and the EPA Science Advisory Board has recommended that EPA reevaluate the ozone mortality literature for possible inclusion in the estimate of total benefits. Based on these new analyses and recommendations, EPA is sponsoring three independent meta-analyses of the ozone-mortality epidemiology literature to inform a determination on inclusion of this important health endpoint. Upon completion and peer-review of the meta-analyses, EPA will make its determination on whether and how benefits of reductions in ozone-related mortality will be included in the benefits analysis for the final interstate air quality rule.

Table XI–2 presents the estimated monetary value of reductions in the incidence of health and welfare effects. PM-related health benefits and ozone benefits are estimated to be approximately $56.9 billion and $82.4 billion annually in 2010 and 2015, respectively. Estimated annual visibility benefits in Southeastern Class I areas brought about by the IAQR are estimated to be $880 million in 2010 and $1.4 billion in 2015. All monetized estimates are stated in 1999$. Table XI–3 presents the total monetized benefits for the years 2010 and 2015. This table also indicates with a "B" those additional health and environmental effects that we were unable to quantify or monetize. These effects are additive to the estimate of total benefits, and EPA believes there is considerable value to the public of the benefits that could not be monetized. A listing of the benefit categories that could not be quantified or monetized in our estimate is provided in Table XI–4.

In summary, EPA's primary estimate of the annual benefits of the rule is approximately 58 + B billion in 2010. In 2015, total monetized benefits are approximately $84 + B billion annually. These estimates account for growth in real gross domestic product (GDP) per capita between the present and the years 2010 and 2015. As the table indicates, total benefits are driven primarily by the reduction in premature fatalities each year, which account for over 90 percent of total benefits.

TABLE XI–1.—ESTIMATED REDUCTIONS IN INCIDENCE OF HEALTH EFFECTS

Endpoint	Constituent	2010 estimated reduction	2015 estimated reduction
Premature Mortality—Adult	$PM_{2.5}$	9,600	13,000
Mortality—Infant	$PM_{2.5}$	22	29
Chronic Bronchitis	$PM_{2.5}$	5,200	6,900
Acute Myocardial Infarction—Total	$PM_{2.5}$	13,000	18,000
Hospital Admissions—Respiratory	$PM_{2.5}$, Ozone	5,200	8,100
Hospital Admissions—Cardiovascular	$PM_{2.5}$	3,700	5,000
Emergency Room Visits—Respiratory	$PM_{2.5}$, Ozone	7,100	9,400
Acute Bronchitis	$PM_{2.5}$	12,000	16,000
Lower Respiratory Symptoms	$PM_{2.5}$	140,000	190,000
Upper Respiratory Symptoms	$PM_{2.5}$	490,000	620,000
Asthma Exacerbation	$PM_{2.5}$	190,000	240,000
Acute Respiratory Symptoms (MRADs *)	$PM_{2.5}$, Ozone	6,400,000	8,500,000
Work Loss Days	$PM_{2.5}$	1,000,000	1,300,000
School Loss Days	Ozone	180,000	390,000

* MRADs = minor restricted activity days.

TABLE XI–2.—ESTIMATED MONETARY VALUE OF REDUCTIONS IN INCIDENCE OF HEALTH AND WELFARE EFFECTS

(Millions of 1999 dollars)

Endpoint group	Constituent	2010 estimated monetary value of reductions	2015 estimated monetary value of reductions
Premature Mortality—Adult	$PM_{2.5}$	$53,000	$77,000
Mortality—Infant	$PM_{2.5}$	130	180
Chronic Bronchitis	$PM_{2.5}$	1,900	2,700
Acute Myocardial Infarction—Total	$PM_{2.5}$	1,100	1,500
Hospital Admissions—Respiratory	$PM_{2.5}$, Ozone	85	130
Hospital Admissions—Cardiovascular	$PM_{2.5}$	78	110
Emergency Room Visits—Respiratory	PM2.5, Ozone	2.0	2.6
Acute Bronchitis	$PM_{2.5}$	4.3	5.7
Lower Respiratory Symptoms	$PM_{2.5}$	2.3	3.0
Upper Respiratory Symptoms	$PM_{2.5}$	13	17
Asthma Exacerbation	$PM_{2.5}$	8.0	10
Acute Respiratory Symptoms (MRADs *)	$PM_{2.5}$, Ozone	320	440
Work Loss Days	$PM_{2.5}$	140	170
School Loss Days	Ozone	13	28
Worker Productivity	Ozone	8.0	17
Visibility—Southeastern Class I Areas	Light Extinction	880	1,400
TOTAL + B **		$58,000	$84,000

B = non-monetized benefits
* MRADs = minor restricted activity days.
** Note total dollar benefits are rounded to the nearest billion and column totals may not add due to rounding.

2. Benefit-Cost Comparison

Based upon Table XI–3, the estimated social costs to implement the proposed rule emission reductions in 2010 and 2015 are $3 and $4 billion annually, respectively (1999$). Thus, the net benefit (social benefits minus social costs) of the program is approximately $55 + B billion annually in 2010 and $80 + B billion annually in 2015. Therefore, implementation of the proposed rule is expected to provide society with a net gain in social welfare based on economic efficiency criteria.

TABLE XI–3.—SUMMARY OF ANNUAL BENEFITS, COSTS, AND NET BENEFITS OF THE INTERSTATE AIR QUALITY RULE
(Billions of 1999 dollars)

Description	2010	2015
Social Costs [a]	2.9	3.7
Social Benefits [b, c].		
Ozone-related benefits	0.1	0.1
PM-related health benefits	56.8 + B	82.3 + B
Visibility benefits	0.9	1.4
Annual Net Benefits (Benefits-Costs) [b, c, d]	$55 + B	$80 + B

Notes:
[a] Note that costs are the estimated total annual costs of reducing pollutants including NO_X and SO_2 in the IAQR region.
[b] As the table indicates, total benefits are driven primarily by PM rèlated health benefits. The reduction in premature fatalities each year accounts for over 90 percent of total benefits. Benefits in this table are associated with NO_X and SO_2 reductions.
[c] Not all possible benefits or disbenefits are quantified and monetized in this analysis. B is the sum of all unquantified benefits and disbenefits. Potential benefit categories that have not been quantified and monetized are listed in Table XI–4.
[d] Net benefits are rounded to nearest billion. Columnar totals may not sum due to rounding.

Every benefit-cost analysis examining the potential effects of a change in environmental protection requirements is limited to some extent by data gaps, limitations in model capabilities (such as geographic coverage), and uncertainties in the underlying scientific and economic studies used to configure the benefit and cost models. Deficiencies in the scientific literature often result in the inability to estimate quantitative changes in health and environmental effects, such as potential increases in premature mortality associated with increased exposure to carbon monoxide. Deficiencies in the economics literature often result in the inability to assign economic values even to those health and environmental outcomes that can be quantified. While these general uncertainties in the underlying scientific and economics literatures (that can cause the valuations to be higher or lower) are discussed in detail in the economic analyses and its supporting documents and references, the key uncertainties which have a bearing on the results of the benefit-cost analysis of this proposed rule include the following:

- The exclusion of potentially significant benefit categories (such as health and ecological benefits of reduction in mercury);
- Errors in measurement and projection for variables such as population growth and baseline incidence rates;
- Uncertainties in the estimation of future year emissions inventories and air quality;
- Variability in the estimated relationships of health and welfare effects to changes in pollutant concentrations;
- Uncertainties in exposure estimation;
- Uncertainties in the size of the effect estimates linking air pollution and health endpoints;
- Uncertainties about relative toxicity of different components within the complex mixture of PM;
- Uncertainties associated with the effect of potential future actions to limit emissions.

Despite these uncertainties, we believe the benefit-cost analysis provides a reasonable indication of the expected economic benefits of the proposed rulemaking in future years under a set of reasonable assumptions.

There are a number of health and environmental effects that we were unable to quantify or monetize. A full appreciation of the overall economic consequences of the proposed rule requires consideration of all benefits and costs expected to result from the proposed rule, not just those benefits and costs which could be expressed here in dollar terms. A listing of the benefit categories that could not be quantified or monetized in our estimate are provided in Table XI–4. These effects are denoted by "B" in Table XI–3 above, and are additive to the estimates of benefits.

We are unable to quantify changes in levels of methylmercury contamination in fish associated with reductions in mercury emissions for this proposal. However, this proposal is anticipated to decrease annual EGU mercury emissions nationwide by 10.6 tons in 2010 or approximately 23.5 percent, by 11.8 tons in 2015 or 26.3 percent, and by 14.3 tons or 32 percent in 2020. Emission reduction percentage decreases are based upon expected mercury emissions changes from fossil-fired EGUs larger than 25 megawatt capacity. In a separate action today, EPA is proposing to regulate mercury and nickel from certain types of electric generating units using the maximum achievable control technology (MACT) provisions of section 112 of the CAA or, in the alternative, using the performance standards provisions under section 111 of the CAA. This proposal will have implications for mercury reductions, and potential interactions may exist between the rulemakings.

TABLE XI–4.—ADDITIONAL NON-MONETIZED BENEFITS OF THE PROPOSED INTERSTATE AIR QUALITY RULE

Pollutant	Unquantified and/or nonmonetized effects
Ozone Health	Premature mortality.[a] Increased airway responsiveness to stimuli. Inflammation in the lung. Chronic respiratory damage. Premature aging of the lungs. Acute inflammation and respiratory cell damage. Increased susceptibility to respiratory infection. Non-asthma respiratory emergency room visits.
Ozone Welfare	Decreased yields for commercial forests. Decreased yields for fruits and vegetables. Decreased yields for commercial and non-commercial crops. Damage to urban ornamental plants. Impacts on recreational demand from damaged forest aesthetics. Damage to ecosystem functions.
PM Health	Low birth weight. Changes in pulmonary function. Chronic respiratory diseases other than chronic bronchitis. Morphological changes. Altered host defense mechanisms. Non-asthma respiratory emergency room visits.
PM Welfare	Visibility in many Class I areas. Residential and recreational visibility in non-Class I areas. Soiling and materials damage. Damage to ecosystem functions.
Nitrogen and Sulfate Deposition Welfare	Impacts of acidic sulfate and nitrate deposition on commercial forests. Impacts of acidic deposition on commercial freshwater fishing. Impacts of acidic deposition on recreation in terrestrial ecosystems. Reduced existence values for currently healthy ecosystems. Impacts of nitrogen deposition on commercial fishing, agriculture, and forests. Impacts of nitrogen deposition on recreation in estuarine ecosystems. Damage to ecosystem functions.
Mercury Health	Neurological disorders. Learning disabilities. Developmental delays. Potential cardiovascular effects.* Altered blood pressure regulation.* Increased heart rate variability.* Myocardial infarction.* Potential reproductive effects in adults.*
Mercury Deposition Welfare	Impact on birds and mammals (e.g., reproductive effects). Impacts on commercial, subsistence, and recreational fishing. Reduced existence values for currently healthy ecosystems.

Notes:
[a] Premature mortality associated with ozone is not separately included in this analysis.
* These are potential effects as the literature is either contradictory or incomplete.

B. Paperwork Reduction Act

The EPA intends to discuss the possible information collection burdens of this action in the SNPR. Assuming that States choose to use the optional trading program detailed in section VIII, the EPA anticipates that the impact on sources will be very small. Under these circumstances, the majority of the sources subject to today's rule are subject to the title IV Acid Rain Program and many sources are already subject to the NO_X SIP Call. For sources subject to both of these programs, EPA does not anticipate any additional monitoring or reporting costs. For more detail on the monitoring and reporting costs for sources not currently subject to the title IV Acid Rain Program and or the NO_X SIP Call *see*, "Monitoring and Reporting Costs Under the Proposed Interstate Air Quality Rule" (January 2004).

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; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

An Agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR part 9 and 48 CFR chapter 15.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*) (RFA), as amended by the Small Business Regulatory Enforcement Fairness Act (Public Law No. 104–121) (SBREFA), provides that whenever an agency is required to publish a general notice of proposed rulemaking, it must prepare and make available an initial regulatory flexibility analysis, unless it certifies that the proposed rule, if promulgated, will not have "a significant economic impact on a substantial number of small entities."

5 U.S.C. 605(b). Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of today's rule on small entities, small entity is defined as: (1) A small business that is identified by the North American Industry Classification System (NAICS) Code, as defined by the Small Business Administration (SBA); (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less that 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field. Table XI–5 lists entities potentially impacted by this proposed rule with applicable NAICS code.

TABLE XI–5.—POTENTIALLY REGULATED CATEGORIES AND ENTITIES

Category	NAICS code [1]	Examples of potentially regulated entities
Industry	221112	Fossil fuel-fired electric utility steam generating units.
Federal government	[2] 22112	Fossil fuel-fired electric utility steam generating units owned by the Federal government.
State/local/Tribal government	[2] 22112	Fossil fuel-fired electric utility steam generating units owned by municipalities.
	921150	Fossil fuel-fired electric utility steam generating units in Indian Country.

[1] North American Industry Classification System.
[2] Federal, State, or local government-owned and operated establishments are classified according to the activity in which they are engaged.

According to the SBA size standards for NAICS code 221112 Utilities-Fossil Fuel Electric Power Generation, a firm is small if, including its affiliates, it is primarily engaged in the generation, transmission, and or distribution of electric energy for sale and its total electric output for the preceding fiscal year did not exceed 4 million megawatt hours.

Courts have interpreted the RFA to require a regulatory flexibility analysis only when small entities will be subject to the requirements of the rule.[101] This rule would not establish requirements applicable to small entities. Instead, it would require States to develop, adopt, and submit SIP revisions that would achieve the necessary SO_2 and NO_X emissions reductions, and would leave to the States the task of determining how to obtain those reductions, including which entities to regulate. Moreover, because affected States would have discretion to choose the sources to regulate and how much emissions reductions each selected source would have to achieve, EPA could not predict the effect of the rule on small entities. Although not required by the RFA, the Agency intends for the SNPR to conduct a general analysis of the potential impact on small entities of possible implementation strategies.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995(Public Law 104–4)(UMRA), establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and Tribal governments and the private sector. Under section 202 of the UMRA, 2 U.S.C. 1532, EPA generally must prepare a written statement, including a cost-benefit analysis, for any proposed or final rule that "includes any Federal mandate that may result in the expenditure by State, local, and Tribal governments, in the aggregate, or by the private sector, of $100,000,000 or more * * * in any one year." A "Federal mandate" is defined under section 421(6), 2 U.S.C. 658(6), to include a "Federal intergovernmental mandate" and a "Federal private sector mandate." A "Federal intergovernmental mandate," in turn, is defined to include a regulation that "would impose an enforceable duty upon State, Local, or Tribal governments," section 421(5)(A)(i), 2 U.S.C. 658(5)(A)(i), except for, among other things, a duty that is "a condition of Federal assistance," section 421(5)(A)(i)(I). A "Federal private sector mandate" includes a regulation that "would impose an enforceable duty upon the private sector," with certain exceptions, section 421(7)(A), 2 U.S.C. 658(7)(A).

Before promulgating an EPA rule for which a written statement is needed under section 202 of the UMRA, section 205, 2 U.S.C. 1535, of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule.

The EPA intends to prepare a written statement for the SNPR consistent with the requirements of section 202 of the UMRA Furthermore, as EPA stated in the proposal, EPA is not directly establishing any regulatory requirements that may significantly or uniquely affect small governments, including Tribal governments. Thus, EPA is not obligated to develop under section 203 of the UMRA a small government agency plan. Furthermore, in a manner consistent with the intergovernmental consultation provisions of section 204 of the UMRA, EPA carried out consultations with the governmental entities affected by this rule.

For several reasons, however, EPA is not reaching a final conclusion as to the applicability of the requirements of UMRA to this rulemaking action. First, it is questionable whether a requirement to submit a SIP revision would constitute a Federal mandate in any case. The obligation for a State to revise its SIP that arises out of section 110(a) of the CAA is not legally enforceable by a court of law, and at most is a condition for continued receipt of highway funds. Therefore, it is possible to view an action requiring such a submittal as not creating any enforceable duty within the meaning of section 421(5)(9a)(I) of UMRA (2 U.S.C. 658 (a)(I)). Even if it did, the duty could be viewed as falling within the exception for a condition of Federal assistance under section 421(5)(a)(i)(I) of UMRA (2 U.S.C. 658(5)(a)(i)(I)).

As noted earlier, however, notwithstanding these issues, EPA plans to prepare for the SNPR the statement that would be required by UMRA if its statutory provisions applied, and the EPA has consulted with governmental entities as would be required by UMRA. Consequently, it is not necessary for EPA to reach a conclusion as to the applicability of the UMRA requirements.

E. Executive Order 13132: Federalism

Executive Order 13132, entitled "Federalism" (64 FR 43255, August 10, 1999), requires EPA to develop an accountable process to ensure "meaningful and timely input by State and local officials in the development of

[101] *See Michigan* v. *EPA*, 213 F.3d 663, 668–69 (D.C. Cir. 2000), *cert. den.* 121 S.Ct. 225, 149 L.Ed.2d 135 (2001). An agency's certification need consider the rule's impact only on entities subject to the rule.

regulatory policies that have federalism implications." "Policies that have federalism implications" is defined in the Executive Order to include regulations that have "substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government."

This proposed rule does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. The CAA establishes the relationship between the Federal government and the States, and this rule does not impact that relationship. Thus, Executive Order 13132 does not apply to this rule. In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicits comment on this proposed rule from State and local officials.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

Executive Order 13175, entitled "Consultation and Coordination with Indian Tribal Governments" (65 FR 67249, November 9, 2000), requires EPA to develop an accountable process to ensure "meaningful and timely input by Tribal officials in the development of regulatory policies that have Tribal implications." This proposed rule does not have "Tribal implications" as specified in Executive Order 13175.

This proposed rule concerns the implementation of the rules that address transport of pollution that causes ozone and PM2.5. The CAA provides for States and Tribes to develop plans to regulate emissions of air pollutants within their jurisdictions. The proposed regulations clarify the statutory obligations of States and Tribes that develop plans to implement this rule. The TAR gives Tribes the opportunity to develop and implement CAA programs, but it leaves to the discretion of the Tribe whether to develop these programs and which programs, or appropriate elements of a program, they will adopt.

This proposed rule does not have Tribal implications as defined by Executive Order 13175. It does not have a substantial direct effect on one or more Indian Tribes, since no Tribe has implemented an air quality management program at this time. Furthermore, this proposed rule does not affect the relationship or distribution of power and responsibilities between the Federal government and Indian Tribes. The CAA and the TAR establish the relationship of the Federal government and Tribes in developing plans to attain the NAAQS, and this proposed rule does nothing to modify that relationship. Because this proposed rule does not have Tribal implications, Executive Order 13175 does not apply.

Assuming a Tribe is implementing such a plan at this time, while the proposed rule would have Tribal implications upon that Tribe, it would not impose substantial direct costs upon it, nor would it preempt Tribal law. As provided above, EPA has estimated that the total annual costs for the rule as implemented by State, Local, and Tribal governments is approximately $3 billion in 2010 and $4 billion in 2010 (1999$). There are currently very few emissions sources in Indian country that could be affected by this rule and the percentage of Tribal land that will be impacted is very small. For Tribes that choose to regulate sources in Indian country, the costs would be attributed to inspecting regulated facilities and enforcing adopted regulations.

Although Executive Order 13175 does not apply to this proposed rule, EPA consulted with Tribal officials in developing this proposed rule. The EPA has encouraged Tribal input at an early stage. Also, the EPA held periodic meetings with the States and the Tribes during the technical development of this rule. In addition, EPA held three calls with Tribal environmental professionals to address concerns specific to the Tribes. These discussions have given EPA valuable information about Tribal concerns regarding the development of this rule. The EPA has provided briefings for Tribal representatives and the newly formed National Tribal Air Association (NTAA), and other national Tribal forums. Input from Tribal representatives has been taken into consideration in development of this proposed rule. The EPA specifically solicits additional comment on this proposed rule from Tribal officials.

G. Executive Order 13045: Protection of Children From Environmental Health and Safety Risks

Executive Order 13045, "Protection of Children from Environmental Health Risks and Safety Risks" (62 FR 19885, April 23, 1997) applies to any rule that (1) is determined to be "economically significant" as defined under Executive Order 12866, and (2) concerns an environmental health or safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, Section 5–501 of the Order directs the Agency to evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency.

This proposed rule is not subject to the Executive Order because it does not involve decisions on environmental health or safety risks that may disproportionately affect children. The EPA believes that the emissions reductions from the strategies proposed in this rulemaking will further improve air quality and will further improve children's health.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

Executive Order 13211 (66 FR 28355, May 22, 2001) provides that agencies shall prepare and submit to the Administrator of the Office of Regulatory Affairs, OMB, a Statement of Energy Effects for certain actions identified as "significant energy actions." Section 4(b) of Executive Order 13211 defines "significant energy actions" as "any action by an agency (normally published in the **Federal Register**) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of final rulemaking, and notices of final rulemaking (1) (i) that is a significant regulatory action under Executive Order 12866 or any successor order, and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) that is designated by the Administrator of the Office of Information and Regulatory Affairs as a "significant energy action." This proposed rule is a significant regulatory action under Executive Order 12866, and this proposed rule may have a significant adverse effect on the supply, distribution, or use of energy. We have prepared a Statement of Energy Effects for this action, which may be briefly summarized as follows:

If States choose to obtain the emission reductions required by this rule by regulating EGUs, EPA projects that approximately 3100 MWs of coal-fired generation may be retired earlier than the generation would have been retired absent today's proposed rule-making. We do not believe that this rule will have any other impacts that exceed the significance criteria. The EPA projects that the average annual electricity price will increase by about 2 percent in 2010, and about 3 percent in 2015.

The EPA believes that a number of features of today's rulemaking serve to reduce its impact on energy supply. First, by allowing the use of a trading program, overall cost and thus impact on energy supply is reduced. Second EPA has provided adequate time for EGUs to install the required controls.

The use of a capped trading program to reduce emissions of SO_2 and NO_X is also consistent with the President's National Energy Policy.

I. National Technology Transfer Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise practical. Voluntary consensus standards are technical standards (*e.g.*, materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. The NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

In the SNPR, EPA will include regulatory language concerning monitoring, recordkeeping, and recording provisions that will apply to certain source categories if States choose to require reductions from them. These provisions may involve technical standards that may implicate the use of voluntary consensus standards. Therefore, EPA will address the NTTAA in the SNPR.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898, "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations," requires Federal agencies to consider the impact of programs, policies, and activities on minority populations and low-income populations. According to EPA guidance,[102] agencies are to assess whether minority or low-income populations face risk or a rate of exposure to hazards that is significant and that "appreciably exceeds or is likely to appreciably exceed the risk or rate to the general population or to the appropriate comparison group."

In accordance with Executive Order 12898, the Agency has considered whether this proposed rule may have disproportionate negative impacts on minority or low income populations. Because the Agency expects this proposed rule to reduce pollutant loadings and exposures generally, negative impacts to these sub-populations which appreciably exceed similar impacts to the general population are not expected.

[102] U.S. Environmental Protection Agency. "Guidance for Incorporating Environmental Justice Concerns in EPA's NEPA Compliance Analyses" (Review Draft). Office of Federal Activities. July 12, 1996.

List of Subjects

40 CFR Part 51

Administrative practice and procedure, Air pollution control, Intergovernmental relations, Nitrogen dioxide, Ozone, Particulate matter, Reporting and recordkeeping requirements, Sulfur oxides, Volatile organic compounds.

40 CFR Part 72

Acid rain, Administrative practice and procedure, Air pollution control, Electric utilities, Intergovernmental relations, Nitrogen oxides, Reporting and recordkeeping requirements, Sulfur oxides.

40 CFR Part 75

Acid rain, Air pollution control, Electric utilities, Nitrogen oxides, Reporting and recordkeeping requirements, Sulfur oxides.

40 CFR Part 96

Administrative practice and procedure, Air pollution control, Nitrogen oxides, Reporting and recordkeeping requirements.

Dated: December 17, 2003.

Michael O. Leavitt,

Administrator.

[FR Doc. 04–808 Filed 1–29–04; 8:45 am]

BILLING CODE 6560–50–P

Federal Register

Friday,
January 30, 2004

Part IV

Environmental Protection Agency

40 CFR Parts 60 and 63

Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units; Proposed Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 63

[OAR–2002–0056; FRL–7606–3]

RIN 2060–AJ65

Proposed National Emission Standards for Hazardous Air Pollutants; and, In the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: In this document, EPA is proposing to: set national emission standards for hazardous air pollutants (NESHAP) pursuant to section 112 of the Clean Air Act (CAA); alternatively, to revise the regulatory finding that it made on December 20, 2000 (65 FR 79825) pursuant to CAA section 112(n)(1)(A); and if the December 2000 finding is revised as proposed herein, to set standards of performance for mercury (Hg) for new and existing coal-fired electric utility steam generating units (Utility Units), as defined in CAA section 112(a)(8), and for nickel (Ni) for new and existing oil-fired Utility Units pursuant to CAA section 111. The decision concerning which authority to base regulation of Hg and Ni emissions on, CAA section 112 or section 111, will depend upon whether EPA takes final action to revise the December 2000 section 112(n)(1)(A) finding in the manner described herein. In either event, however, EPA intends to require reductions in the emissions of Hg and Ni from coal- and oil-fired Utility Units, respectively. This action is one part of a broader effort to issue a coordinated set of emissions limitations for the power sector.

In December 2000, EPA found pursuant to CAA section 112(n)(1)(A) that regulation of coal- and oil-fired Utility Units under CAA section 112 is appropriate and necessary. Today's proposed section 112 "MACT" rule would require coal- and oil-fired Utility Units to meet hazardous air pollutant (HAP) emissions standards reflecting the application of the maximum achievable control technology (MACT) determined pursuant to the procedures set forth in CAA section 112(d). The EPA also is co-proposing and soliciting comment on implementing a cap-and-trade program under section 112, similar to that being proposed under section 111 of the CAA.

Coal- and oil-fired Utility Units emit a wide variety of metal, organic, and inorganic HAP, depending on the type of fuel that is combusted. The proposed CAA section 112 MACT rule would limit emissions of Hg and Ni. Exposure to Hg and Ni above identified thresholds has been demonstrated to cause a variety of adverse health effects.

Today's proposed amendments to CAA section 111 rules would establish a mechanism by which Hg emissions from new and existing coal-fired Utility Units would be capped at specified, nation-wide levels. A first phase cap would become effective in 2010 and a second phase cap in 2018. Facilities would demonstrate compliance with the standard by holding one "allowance" for each ounce of Hg emitted in any given year. Allowances would be readily transferrable among all regulated facilities. We believe that such a "cap and trade" approach to limiting Hg emissions is the most cost effective way to achieve the reductions in Hg emissions from the power sector that are needed to protect human health and the environment.

The added benefit of this cap-and-trade approach is that it dovetails well with the sulfur dioxide (SO_2) and nitrogen oxides (NO_X) Interstate Air Quality Rule (IAQR) published elsewhere in today's **Federal Register**. That proposed rule would establish a broadly-applicable cap and trade program that would significantly limit SO_2 and NO_X emissions from the power sector. The advantage of regulating Hg at the same time and using the same regulatory mechanism as for SO_2 and NO_X is that significant Hg emissions reductions can and will be achieved by the air pollution controls designed and installed to reduce SO_2 and NO_X. In other words, significant Hg emissions reductions can be obtained as a "co-benefit" of controlling emissions of SO_2 and NO_X. Thus, the coordinated regulation of Hg, SO_2, and NO_X allows Hg reductions to be achieved in a cost effective manner. This is consistent with Congress's intent expressed in CAA section 112(n), that EPA would regulate HAP emissions from Utility Units only after taking into account compliance with other CAA programs.

This action also proposes to add Performance Specification 12A, "Specification and Test Methods for Total Vapor Phase Mercury Continuous Emission Monitoring Systems in Stationary Sources" to 40 CFR part 60, appendix B, and to add one EPA method to 40 CFR part 63, appendix A: Method 324, "Determination of Vapor Phase Flue Gas Mercury Emissions from Stationary Sources Using Dry Sorbent Trap Sampling."

DATES: *Comments.* Submit comments on or before March 30, 2004.

Public Hearing. The EPA will be holding a public hearing on today's proposal during the public comment period. The details of the public hearing, including the time, date, and location, will be provided in a future **Federal Register** notice and announced on EPA's Web site for this rulemaking *http://www.epa.gov/ttn/atw/combust/utiltox/utoxpg.* The public hearing will provide interested parties the opportunity to present data, views, or arguments concerning the proposed rules. The EPA may ask clarifying questions during the hearing, but will not respond to the presentations or comments at that time. Written comments and supporting information submitted during the comment period will be considered with the same weight as any oral comments and supporting information presented at a public hearing.

ADDRESSES: *Comments.* Comments may be submitted by mail (in duplicate, if possible) to EPA Docket Center (Air Docket), U.S. EPA West (6102T), Room B–108, 1200 Pennsylvania Ave., NW., Washington, DC 20460, Attention Docket ID No. OAR–2002–0056. By hand delivery/courier, comments may be submitted (in duplicate, if possible) to EPA Docket Center, Room B–108, U.S. EPA West, 1301 Constitution Ave., NW, Washington, DC 20460, Attention Docket ID No. OAR–2002–0056. Also, comments may be submitted electronically according to the detailed instructions as provided in the **SUPPLEMENTARY INFORMATION** section.

Public Hearing. The EPA will be holding a public hearing on today's proposal during the public comment period. The details of the public hearing, including the time, date, and location, will be provided in a future **Federal Register** notice and announced on EPA's Web site for this rulemaking *http://www.epa.gov/ttn/atw/combust/tuiltox/utoxpg.*

Docket. The official public docket is available for public viewing at the EPA Docket Center, EPA West, Room B–108, 1301 Constitution Ave., NW., Washington, DC 20460.

FOR FURTHER INFORMATION CONTACT: William Maxwell, Combustion Group (C439–01), Emission Standards Division, Office of Air Quality Planning and Standards, U.S. EPA, Research Triangle Park, NC 27711, telephone number (919) 541–5430, fax number (919) 541–5450, electronic mail (e-mail) address, *maxwell.bill@epa.gov.*

SUPPLEMENTARY INFORMATION: *Regulated Entities.* Categories and entities potentially regulated by this action include the following:

Category	NAICS code [1]	Examples of potentially regulated entities
Industry	221112	Fossil fuel-fired electric utility steam generating units.
Federal government	[2] 221122	Fossil fuel-fired electric utility steam generating units owned by the Federal government.
State/local/tribal government	[2] 221122	Fossil fuel-fired electric utility steam generating units owned by municipalities.
	921150	Fossil fuel-fired electric utility steam generating units in Indian Country.

[1] North American Industry Classification System.
[2] Federal, State, or local government-owned and operated establishments are classified according to the activity in which they are engaged.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. This table lists examples of the types of entities EPA is now aware could potentially be regulated by this action. Other types of entities not listed could also be affected. To determine whether your facility, company, business, organization, etc., is regulated by this action, you should examine the applicability criteria in § 63.9981 of the proposed rule or §§ 60.45a and 60.46a of the proposed NSPS amendments. If you have any questions regarding the applicability of this action to a particular entity, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

Docket. The EPA has established an official public docket for this action including both Docket ID No. OAR–2002–0056 and Docket ID No. A–92–55. The official public docket consists of the documents specifically referenced in this action, any public comments received, and other information related to this action. Not all items are listed under both docket numbers, so interested parties should inspect both docket numbers to ensure that they have received all materials relevant to the proposed rule. The official public docket is available for public viewing at the EPA Docket Center (Air Docket), EPA West, Room B–108, 1301 Constitution Ave., NW., Washington, DC. The EPA Docket Center Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742. A reasonable fee may be charged for copying docket materials.

Electronic Access. You may access this **Federal Register** document electronically through the Internet under the **Federal Register** listings at *http://www.epa.gov/fedrgstr/.*

An electronic version of the public docket is available through EPA's electronic public docket and comment system, EPA Dockets. You may use EPA Dockets at *http://www.epa.gov/edocket/* to submit or view public comments, access the index listing of the contents of the official public docket, and access those documents in the public docket that are available electronically. Once in the system, select "search," then key in the appropriate docket identification number.

Certain types of information will not be placed in EPA Dockets. Information claimed as confidential business information (CBI) and other information whose disclosure is restricted by statute, which is not included in the official public docket, will not be available for public viewing in EPA's electronic public docket. The EPA's policy is that copyrighted material will not be placed in EPA's electronic public docket but will be available only in printed paper form in the official public docket. To the extent feasible, publicly available docket materials will be made available in EPA's electronic public docket. When a document is selected from the index list in EPA Dockets, the system will identify whether the document is available for viewing in EPA's electronic public docket. Although not all docket materials may be available electronically, you may still access any of the publicly available docket materials through the EPA Docket Center.

For public commenters, it is important to note that EPA's policy is that public comments, whether submitted electronically or on paper, will be made available for public viewing in EPA's electronic public docket as EPA receives them and without change, unless the comment contains copyrighted material, CBI, or other information whose disclosure is restricted by statute. When EPA identifies a comment containing copyrighted material, EPA will provide a reference to that material in the version of the comment that is placed in EPA's electronic public docket. The entire printed comment, including the copyrighted material, will be available in the public docket.

Public comments submitted on computer disks that are mailed or delivered to the docket will be transferred to EPA's electronic public docket. Public comments that are mailed or delivered to the Docket will be scanned and placed in EPA's electronic public docket. Where practical, physical objects will be photographed, and the photograph will be placed in EPA's electronic public docket along with a brief description written by the docket staff.

For additional information about EPA's electronic public docket, visit EPA Dockets online or see 67 FR 38102, May 31, 2002.

You may submit comments electronically, by mail, or through hand delivery/courier. To ensure proper receipt by EPA, identify the appropriate docket identification number in the subject line on the first page of your comment. Please ensure that your comments are submitted within the specified comment period. Comments received after the close of the comment period will be marked "late." The EPA is not required to consider these late comments. However, late comments may be considered if time permits.

Electronically. If you submit an electronic comment as prescribed below, EPA recommends that you include your name, mailing address, and an e-mail address or other contact information in the body of your comment. Also include this contact information on the outside of any disk or CD-ROM you submit, and in any cover letter accompanying the disk or CD-ROM. This ensures that you can be identified as the submitter of the comment and allows EPA to contact you in case EPA cannot read your comment due to technical difficulties or needs further information on the substance of your comment. The EPA's policy is that EPA will not edit your comment, and any identifying or contact information provided in the body of a comment will be included as part of the comment that is placed in the official public docket and made available in EPA's electronic public docket. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment.

Your use of EPA's electronic public docket to submit comments to EPA electronically is EPA's preferred method for receiving comments. Go directly to EPA Dockets at *http://www.epa.gov/edocket* and follow the online instructions for submitting comments. To access EPA's electronic public docket from the EPA Internet home page, select "Information Sources," "Dockets," and "EPA Dockets." Once in the system, select "search," and then key in Docket ID No. OAR–2002–0056. The system is an anonymous access system, which means EPA will not know your identity, e-mail address, or other contact information unless you provide it in the body of your comment.

Comments may be sent by e-mail to *a-and-r-docket@epa.gov,* Attention Docket ID No. OAR–2002–0056. In contrast to EPA's electronic public docket, EPA's e-mail system is not an anonymous access system. If you send an e-mail comment directly to the Docket without going through EPA's electronic public docket, EPA's e-mail system automatically captures your e-mail address. E-mail addresses that are automatically captured by EPA's e-mail system are included as part of the comment that is placed in the official public docket and made available in EPA's electronic public docket.

You may submit comments on a disk or CD–ROM that you mail to the mailing address identified below. These electronic submissions will be accepted in WordPerfect or ASCII file format. Avoid the use of special characters and any form of encryption.

By Mail. Send your comments (in duplicate if possible) to EPA Docket Center (Air Docket), U.S. EPA West (6102T), Room B–108, 1200 Pennsylvania Ave., NW., Washington, DC, 20460, Attention Docket ID No. OAR–2002–0056. The EPA requests a separate copy also be sent to the contact person listed above (*see* **FOR FURTHER INFORMATION CONTACT**).

By Hand Delivery or Courier. Deliver your comments (in duplicate, if possible) to EPA Docket Center, Room B–102, U.S. EPA West, 1301 Constitution Ave., NW., Washington, DC, 20460, Attention Docket ID No. OAR–2002–0056. Such deliveries are only accepted during the Docket's normal hours of operation as identified above.

By Facsimile. Fax your comments to (202) 566–1741, Attention Docket ID No. OAR–2002–0056.

CBI. Do not submit information that you consider to be CBI electronically through EPA's electronic public docket or by e-mail. Send or deliver information identified as CBI only to the following address: Mr. William Maxwell, c/o OAQPS Document Control Officer (Room C404–2), U.S. EPA, Research Triangle Park, 27711, Attention Docket ID No. OAR–2002–0056. You may claim information that you submit to EPA as CBI by marking any part or all of that information as CBI (if you submit CBI on disk or CD–ROM, mark the outside of the disk or CD–ROM as CBI and then identify electronically within the disk or CD–ROM the specific information that is CBI). Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

In addition to one complete version of the comment that includes any information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket and EPA's electronic public docket. If you submit the copy that does not contain CBI on disk or CD–ROM, mark the outside of the disk or CD–ROM clearly that it does not contain CBI. Information not marked as CBI will be included in the public docket and EPA's electronic public docket without prior notice. If you have any questions about CBI or the procedures for claiming CBI, please consult the person identified in the **FOR FURTHER INFORMATION CONTACT** section.

Public Hearing. Persons interested in presenting oral testimony should contact Ms. Kelly Hayes, Combustion Group (C439–01), Emission Standards Division, Office of Air Quality Planning and Standards, U.S. EPA, Research Triangle Park, North Carolina 27711, telephone (919) 541–5578, at least 2 days in advance of the public hearing. Persons interested in attending the public hearing must also call Ms. Kelly Hayes to verify the time, date, and location of the hearing.

The public hearing will provide interested parties the opportunity to present data, views, or arguments concerning the proposed rule. The EPA will ask clarifying questions during the oral presentation but will not respond to the presentations or comments. Written statements and supporting information will be considered with the same weight as any oral statement and supporting information presented at a public hearing.

Outline. The information presented in this preamble is organized as follows:

I. Background Information

A. What Is the Regulatory Development Background?

1. What Is the Statutory Background?

In the 1990 Amendments to the CAA, Congress substantially modified section 112 of the CAA, which is the provision of the CAA that expressly addresses HAP. Among other things, CAA section 112 sets forth a list of 188 HAP, to which EPA can add, and requires EPA to list categories and subcategories of "major sources" of listed pollutants. Congress defined "major source" as any stationary source [1] or group of stationary sources at a single location and under common control that emits or has the potential to emit 10 tons per year or more of any HAP or 25 tons per year or more of any combination of HAP. (*See* CAA section 112(a)(1).)

Section 112 further requires EPA to list categories and subcategories of area sources [2] provided those sources meet one of the following statutory criteria: (1) EPA determines that the category or subcategory of area sources presents a threat of adverse effects to human health or the environment in a manner that warrants regulation under CAA section 112; or (2) the category or subcategory of area sources falls within the purview of CAA section 112(k)(3)(B) (the Urban Area Source Strategy). Once EPA has listed a source category, whether it be a category of major sources or area sources, section 112(d) calls for the promulgation of emission standards.

Congress, therefore, treated area sources differently from major sources in that categories of major sources are listed under CAA section 112 based solely on the number of tons of HAP emitted from sources in the category on an annual basis. By contrast, area source categories are not listed unless either the health and environmental effects warrant regulation under section 112, or reductions from the category are required to meet the requirements of the Urban Area Source Strategy.

Congress also treated Utility Units differently from major and area sources. (*See* CAA section 112(n)(1)(A).) Specifically, Congress directed EPA to conduct a study that analyzed what hazards to public health resulting from emissions of HAP from Utility Units, if any, would reasonably be anticipated to occur following imposition of the other requirements of the CAA. Congress further directed EPA to report to it the results of such study. Finally, Congress directed EPA to determine whether, based on the results of the study, regulation of Utility Units under CAA section 112 was appropriate and necessary. Congress did not define the terms "appropriate" and "necessary," but required that regulation of Utility Units under section 112 occur only if EPA found such regulation to be both appropriate *and* necessary.

2. What Was the Scope of, and Basis for, EPA's December 2000 Finding?

Scope of finding. On December 20, 2000, pursuant to CAA section 112(n)(1)(A), EPA determined that it was both appropriate and necessary to regulate coal- and oil-fired Utility Units under section 112 of the CAA. (65 FR 79826) Solely because of this finding, EPA added these units to the list of source categories under section 112(c) of the CAA. (Id.) In December 2000, EPA also concluded that the impacts associated with HAP emissions from natural-gas fired Utility Units were negligible and that regulation of such units under CAA section 112 was not appropriate or necessary.

Basis for finding. Nature of record. The EPA premised its December 2000 "appropriate and necessary" finding primarily on the results of the February 1998 "Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units—Final Report to Congress" (Utility RTC). The EPA prepared this study pursuant to the terms of CAA section 112(n)(1)(A) and provided it to Congress. The EPA also based its December 2000 finding on certain information that it obtained following completion of the Utility RTC, which served only to confirm the conclusions of the Utility RTC.

In the Utility RTC, EPA examined 67 of the 188 HAP listed in section 112(b) of the CAA. These 67 HAP represent the pollutants EPA believes could potentially be emitted from Utility Units. The EPA assessed these HAP in terms of potential health hazards and

[1] A "stationary source" of hazardous air pollutants is any building, structure, facility or installation that emits or may emit any air pollutant. CAA Section 111(a)(3).

[2] A stationary source that is not a major source is an "area source." CAA section 112(a)(2).

summarized its conclusions with regard to the HAP in the Utility RTC.

The Utility RTC identifies Hg as the HAP emitted from Utility Units that is of greatest concern from a public health perspective. (Executive Summary Utility RTC ("ES"), at 27.) The health effects of Hg exposure are presented elsewhere in this preamble.

The Utility RTC also included information indicating that Ni was the pollutant of concern from oil-fired Utility Units due to its high level of emissions from those units and the potential health effects arising from exposure to it. The health effects of Ni exposure also are presented elsewhere in this preamble.

As for the other non-Hg and non-Ni metallic HAP examined, EPA made the following conclusions. With regard to arsenic, a metal, EPA concluded that there were several uncertainties associated with both the cancer risk estimates from arsenic and the health effects data for arsenic, and that further analyses were needed to characterize the risks posed by arsenic emissions from Utility Units (ES at 21). As to lead and cadmium, which are also metals, EPA found that the emission quantities and inhalation risks of these HAP were low and did not warrant further evaluation (ES at 24). As for the remaining, non-Hg, non-Ni metallic HAP, EPA found that such pollutants posed no hazards to public health.

The EPA also examined HCl and HF, which are inorganic or acid gas HAP, and found no exceedances of the health benchmark for either substance (ES at 24). As for dioxins, organic HAP, EPA concluded that the quantitative exposure and risk results for such HAP "d(id) not conclusively demonstrate the existence of health risks of concern associated with exposures to utility emissions either on a national scale or from any actual individual utility." (Utility RTC at 11–5.) Finally, EPA concluded that emissions from Utility Units of the remaining HAP examined in the Study did not appear to be a concern for public health (65 FR 79827).

As part of the Utility RTC, EPA also examined several provisions of the CAA relating to electric utilities, including different sections of title I and title IV (Utility RTC, Ch.1). The EPA did not focus in the Utility RTC or the December 2000 finding, however, on whether section 111 of the CAA could be used specifically to regulate HAP from new and existing Utility Units, or the extent to which regulation under section 111 might address any HAP-related issues for Utility Units.

Following completion of the Utility RTC, EPA obtained additional information, which is summarized in EPA's December 20, 2000, notice. That information addressed Hg and methylmercury and confirmed the hazards to public health associated therewith.[4]

In addition, at the direction of Congress, EPA funded the National Academy of Sciences (NAS) to perform an independent evaluation of the available data related to the health impacts of methylmercury and provide recommendations for EPA's reference dose (RfD). An RfD is the amount of a chemical which, when ingested daily over a lifetime, is anticipated to be without adverse health effects to humans, including sensitive subpopulations. The NAS conducted an 18-month study of the available data on the health effects of methylmercury and provided EPA with a report of its findings in July 2000. Although the NAS recommended reliance on different studies for setting the methylmercury RfD, the value of EPA's RfD was found to be scientifically justifiable.

December 2000 finding. In December 2000, EPA found Hg to be the HAP emitted by Utility Units that was of greatest concern from a public health perspective because Hg is highly toxic, persistent, and bioaccumulates in food chains. The EPA also found that the data which it had gathered since the Utility RTC corroborated the previous nationwide Hg emissions estimate and confirmed that Utility Units are the largest anthropogenic source of Hg emissions in the United States. The EPA further found that there is a plausible link between methylmercury concentrations in fish and Hg emissions from coal-fired Utility Units (65 FR 79830).

Based on these findings, EPA stated that it was "appropriate to regulate HAP emissions from coal- and oil-fired electric utility steam generating units under section 112 of the CAA because, as documented in the utility RTC * * *, electric utility steam generating units are the largest domestic source of Hg emissions and Hg in the environment presents significant hazards to public health and the environment." The EPA further noted that the National Academy of Science's study "confirm(ed) that Hg in the environment presents significant hazards to public health."

The EPA also found that it was appropriate to regulate HAP emissions from coal- and oil-fired Utility Units under CAA section 112 because EPA had identified several control options that should reduce these emissions. (*See* 65 FR 79830 (noting that "There are a number of alternative control strategies that are effective in controlling *some of the HAP* emitted from electric utility steam generating units.") (emphasis added).) Thus, EPA's appropriateness finding in December 2000 focused on the significant health hazards associated with Hg and the availability of control strategies for certain HAP. The determination also rested, in part, however, on the uncertainties regarding the public health effects associated with HAP from oil-fired units. (*See* 65 FR 79830.) Although EPA did not specify in the December 2000 notice which HAP emissions from oil-fired units posed hazards to public health that warrant regulation, the record demonstrates that Ni was the HAP emitted by oil-fired units that was of greatest concern from a public health perspective because of the significant quantities of Ni emitted from oil-fired units and the scope and number of adverse health effects associated with Ni exposure. However, only 11 of the 137 oil-fired Utility Units considered in this finding posed an inhalation risk to human health greater than one in a million (1×10^{-6}).

Finally, EPA stated that it was "necessary" to regulate HAP emissions from coal- and oil-fired Utility Units "because the implementation of other requirements under the CAA will not adequately address the serious public health and environmental hazards arising from such emissions." (*See* 65 FR 79830.)

The EPA had a desire to keep the regulatory process open and include all stakeholders involved. After discussion with the various stakeholder groups, it was decided that the most effective means of ensuring that inclusion was to form a Working Group under the existing Permits, New Source Review, and Toxics Subcommittee of the Clean Air Act Advisory Committee (CAAAC), chartered under the Federal Advisory Committee Act (FACA). The Working Group was designed and created to foster active participation from stakeholders, including environmental groups, the regulated industry, and State and local regulatory agencies. Over the period of August 2001 to March 2003, the Working Group held 14 meetings and discussed a number of issues related to the proposed CAA section 112 rule.

[4] Subsequent to issuance of the December 2000 Notice, EPA also conducted additional modeling for HCl, chlorine (Cl_2), and HF. Such modeling predicted concentrations of these HAP to be well below the relevant respiratory benchmark concentrations for the model plants examined. Hazard indices did not exceed 0.2 for any of these HAP. This modeling, therefore, confirmed the conclusion EPA reached in the Utility RTC, which is that inorganic or acid gas HAP from Utility Units, even in the absence of additional control measures, do not pose any hazards to the public health.

To enhance the public's ability to participate, EPA maintained an Internet website to disseminate information on the Working Group and the regulatory process. The recommendations of the Working Group and other interested parties have been considered by EPA in developing the proposed rule for coal- and oil-fired Utility Units. On several occasions, EPA met with individual stakeholder groups to discuss the status of the proposed rulemaking and to hear their concerns and comments regarding the proposed CAA section 112 rule.

B. What Is the Relationship Between the Proposed Rule and Other Combustion Rules?

The EPA has previously developed two other combustion-related MACT standards in addition to today's proposed rule for coal- and oil-fired Utility Units. The EPA proposed standards for industrial, commercial, and institutional boilers and process heaters (IB) on January 13, 2003 (68 FR 1660) and promulgated standards for stationary combustion turbines (CT) in 2004. These regulations have been issued pursuant to CAA section 112, but not under CAA section 112(n)(1)(A), as is today's proposal, because section 112(n)(1)(A) is uniquely applicable to Utility Units as defined by the CAA.

All three of the rules pertain to HAP emission sources that combust fossil fuels for electrical power, process operations, or heating. The differences among these rules are due to the size of the unit (megawatts electric (MWe) or British thermal unit per hour (Btu/hr)) they regulate, the boiler/furnace technology they employ, or the portion of their electrical output (if any) for sale to any utility power distribution systems.

Section 112(a)(8) of the CAA defines an "electric utility steam generating unit" as "any fossil fuel-fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale." A unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is also considered a Utility Unit. All of the MWe ratings quoted in the proposed rule are considered to be the original nameplate rated capacity of the unit. Cogeneration is defined as the simultaneous production of power (electricity) and another form of useful thermal energy (usually steam or hot water) from a single fuel-consuming process. Today's proposed section 112 MACT rule would not regulate a unit that meets the definition of a Utility Unit but combusts natural gas greater than 98 percent of the time.

The CT rule regulates HAP emissions from all simple-cycle and combined-cycle turbines producing electricity or steam for any purpose. Because of their combustion technology, simple-cycle and combined-cycle turbines (with the exception of integrated gasification combined cycle (IGCC) units that burn gasified coal gas) are not considered Utility Units for purposes of today's proposed rule.

Any combustion unit that produces steam to serve a generator that produces electricity exclusively for industrial, commercial, or institutional purposes is considered an IB unit. A fossil-fuel-fired combustion unit that serves a generator that produces electricity for sale is not considered to be a Utility Unit under the proposed rule if its size is less than or equal to 25 MWe. Also, a cogeneration facility that sells electricity to any utility power distribution system equal to more than one-third of their potential electric output capacity and more than 25 MWe is considered to be an electric utility steam generating unit. However, a cogeneration facility that meets the above definition of a Utility Unit during any portion of a year would be subject to the proposed rule.

Because of the similarities in the design and operational characteristics of the units that would be regulated by the different combustion rules, there are situations where coal- or oil-fired units potentially could be subject to multiple MACT rules. An example of this situation would be cogeneration units that are covered under the proposed IB rule, potentially meeting the definition of a Utility Unit, and vice versa. This might occur where a decision is made to increase/decrease the proportion of production output being supplied to the electric utility grid, thus causing the unit to exceed the IB/electric utility cogeneration criteria (*i.e.* greater than one-third of its potential output capacity and greater than 25 MWe).

The EPA solicits comment on the extent to which this situation might occur. Given the differences between rules, how should EPA address reclassification of the sources between the two rules, particularly with regard to initial and ongoing compliance requirements and schedules? (As noted above, EPA is proposing to consider as a Utility Unit any cogeneration unit that meets the definition noted earlier at any time during a year.)

Another situation could occur where one or more coal- or oil-fired Utility Unit(s) share an air pollution control device (APCD) and/or an exhaust stack with one or more similarly-fueled IB units. To demonstrate compliance with two different rules, the emissions have to either be apportioned to the appropriate source or the more stringent emission limit must be met. Data needed to apportion emissions are not currently required by the proposed rule or the proposed IB rule.

The EPA solicits comment on the extent to which this situation might occur. Given potential differences between rules, how should EPA address apportionment of the emissions to the individual sources with regard to initial and ongoing compliance requirements? The EPA specifically requests comment on the appropriateness of a mass balance-type methodology to determine pollutant apportionment between sources both pre-APCD and post-APCD.

C. What Are the Health Effects of HAP Emitted From Coal- and Oil-Fired Utility Units?

Data collected during development of the proposed section 112 rule show that coal- and oil-fired Utility Units emit a wide variety of metal, organic, and inorganic HAP, depending on the type of fuel that is combusted. Today's proposed rules, both under CAA section 111 and 112, would protect air quality and promote the public health by reducing emissions of Hg and Ni from coal- and oil-fired Utility Units. Exposure to Hg and Ni at sufficiently high levels is associated with a variety of adverse health effects. The EPA cannot currently quantify whether, and the extent to which, the adverse health effects occur in the populations surrounding these facilities, and the contribution, if any, of the facilities to those problems. However, to the extent the adverse effects do occur, either of today's proposed actions would reduce emissions and subsequent exposures. Following is a summary of the health effects for the Hg and Ni emissions that would be reduced by either of the proposed rules.

Mercury. Mercury is a persistent, bioaccumulative toxic metal that exists in three forms: elemental Hg (Hg^0), inorganic Hg (Hg^{++}) compounds (primarily mercuric chloride), and organic Hg compounds (primarily methylmercury). Each form exhibits different health effects. Various major sources may release elemental or inorganic Hg; environmental methylmercury, the form of concern for this rulemaking, is typically formed by biological processes after Hg has precipitated from the air and deposited into water bodies.

Mercury is toxic to humans from both the inhalation and oral exposure routes. In the proposed rulemaking, we focus on oral exposure of methylmercury as it is the route of primary interest for human exposures. Methylmercury is a well-established human neurotoxin although, as with many chemicals, the scientific community is divided on the specific dose and frequency of exposure required to elicit adverse effects. According to the NAS, chronic low-dose prenatal methylmercury exposure has been associated with poor performance on neurobehavioral tests in children, including those tests that measure attention, visual-spacial ability, verbal memory, language ability, fine motor skills, and intelligence. Furthermore, it has been hypothesized that there is an association between methylmercury exposure and an increased risk of coronary disease in adults; however, this hypothesis warrants further study as the few studies currently available present conflicting results. (NEJOM; 2002; Yoshizawa, 2002; Guallar, 2002; Salonen, 1999; Salonen, 1995; Bolger, 2003).

Fish consumption dominates the pathway for human and wildlife exposure to methylmercury. There is a great deal of variability among individuals in fish consumption rates. Critical elements in estimating methylmercury exposure and risk from fish consumption include the species of fish consumed, the concentrations of methylmercury in the fish, the quantity of fish consumed, and how frequently the fish is consumed. The typical U.S. consumer eating a wide variety of fish from restaurants and grocery stores is not in danger of consuming harmful levels of methylmercury from fish and is not advised to limit fish consumption. Those who regularly and frequently consume large amounts of fish, either marine or freshwater, are more exposed. Because the developing fetus may be the most sensitive to the effects from methylmercury, women of child-bearing age are regarded as the population of greatest interest. The EPA, Food and Drug Administration, and many States have issued fish consumption advisories to inform this population of protective consumption levels.

The EPA's 1997 Mercury Study RTC supports a plausible link between anthropogenic releases of Hg from industrial and combustion sources in the U.S. and methylmercury in fish. However, these fish methylmercury concentrations also result from existing background concentrations of Hg (which may consist of Hg from natural sources, as well as Hg which has been re-emitted from the oceans or soils) and deposition from the global reservoir (which includes Hg emitted by other countries). Given the current scientific understanding of the environmental fate and transport of this element, it is not possible to quantify how much of the methylmercury in fish consumed by the U.S. population is contributed by U.S. emissions relative to other sources of Hg (such as natural sources and re-emissions from the global pool). As a result, the relationship between Hg emission reductions from Utility Units and methylmercury concentrations in fish cannot be calculated in a quantitative manner with confidence. In addition, there is uncertainty regarding over what time period these changes would occur. This is an area of ongoing study.

Given the present understanding of the Hg cycle, the flux of Hg from the atmosphere to land or water at one location is comprised of contributions from: the natural global cycle; the cycle perturbed by human activities; regional sources; and local sources. Recent advances allow for a general understanding of the global Hg cycle and the impact of the anthropogenic sources. It is more difficult to make accurate generalizations of the fluxes on a regional or local scale due to the site-specific nature of emission and deposition processes. Similarly, it is difficult to quantify how the water deposition of Hg leads to an increase in fish tissue levels. This will vary based on the specific characteristics of the individual lake, stream, or ocean.

As part of routine U.S. population surveillance, the U.S. Centers for Disease Control (CDC) assessed Hg concentrations in blood of over 1,500 women of child-bearing age. A recent analysis of these data reported that about 8 percent of these women of child-bearing age have levels of Hg in their blood that are at or above the U.S. EPA's RfD. The CDC also surveyed the same group of women about their eating habits. The surveyed women reported eating shrimp and tuna more frequently than other fish and shellfish options. Hg concentrations in seafood may be largely responsible for elevated levels of Hg in U.S. women of child-bearing age. We have little information about how Hg emissions from U.S. power plants may affect Hg concentrations in shrimp, tuna, and other marine fish. We seek comment on this issue and in particular, any data or other information that would allow us to better estimate the extent to which today's proposal would reduce blood Hg concentrations in U.S. women.

Recent estimates (which are highly uncertain) of annual total global Hg emissions from all sources (natural and anthropogenic) are about 5,000 to 5,500 tons per year (tpy). Of this total, about 1,000 tpy are estimated to be natural emissions and about 2,000 tpy are estimated to be contributions through the natural global cycle of re-emissions of Hg associated with past anthropogenic activity. Current anthropogenic emissions account for the remaining 2,000 tpy. Point sources such as fuel combustion; waste incineration; industrial processes; and metal ore roasting, refining, and processing are the largest point source categories on a world-wide basis. Given the global estimates noted above, U.S. anthropogenic Hg emissions are estimated to account for roughly 3 percent of the global total, and U.S. utilities are estimated to account for about 1 percent of total global emissions. (Utility RTC at 7–1 to 7–2.)

Nickel. Nickel is a natural element of the earth's crust; therefore, small amounts are found in food, water, soil and air. Food is the major source of Ni exposure. Ni is an essential element in some animal species. Individuals may also be exposed to Ni if they are employed in occupations involved in Ni production, processing, and use, or through contact with every day items such as Ni-containing jewelry and stainless steel cooking and eating utensils, and by smoking tobacco. The route of human exposure to Ni that we are concerned with in this rulemaking is Ni that is found in ambient air at very low levels as a result of releases from oil-fired Utility Units. The differing forms of Ni have varying levels of toxicity. There is great uncertainty about the different species of Ni emitted by Utility Units.

Respiratory effects, including a type of asthma specific to Ni, decreased lung function and bronchitis have been reported in humans who have been occupationally exposed to high-levels of Ni in air. Animal studies have reported effects on the lungs and immune system from inhalation exposure to soluble and insoluble Ni compounds (nickel oxide, subsulfide, sulfate heptahydrate). Soluble Ni compounds are more toxic to the respiratory tract than less soluble compounds. The EPA has not established a reference concentration (RfC)for Ni. No information is available regarding the reproductive or developmental effects of Ni in humans, but animal studies have reported such effects, although a consistent dose-response relationship has not been seen. Human and animal studies have reported an increased risk of lung and nasal cancers from exposure to Ni refinery dusts and Ni subsulfide. The EPA has classified Ni carbonyl as a Group B2, probable human carcinogen based on lung tumors in animals. (*see* *http://www.epa.gov/ttn/atw/hlthef/nickel.html*).

We ask for comment on all aspects of our proposed revised determination that it is necessary and appropriate to regulate Ni emissions from oil-fired Utility Units under section 112. In particular, we ask for comments and additional information related to the speciation of Ni compounds directly emitted by oil-fired Utility Units and those that may be formed through atmospheric transformation, as well as information on potential health effects. We also ask commenters—especially current owners and operators of potentially affected oil-fired units—to provide information on the current operating status and anticipated mode of operation in the future of potentially affected oil-fired Utility Units, including current control technology. To the extent possible, we would like to have up-to-date information on fuel use, emissions, stack parameters and other location-specific data that would be relevant to the assessment of emissions, dispersion, and ambient air quality. We also ask for comment on our finding in the Utility RTC that only 11 of 137 oil-fired Utility Units considered in the Utility RTC posed an inhalation risk to human health greater than one in a million (1×10^{-6}) and whether data exists as to whether emissions from these plants no longer pose such risk.

II. Proposed National Emission Standards for Hazardous Air Pollutants for Mercury and Nickel From Stationary Sources: Electric Utility Steam Generating Units

A. What Is the Statutory Authority for the Proposed Section 112 Rule?

Section 112 of the CAA requires that EPA promulgate regulations requiring the control of HAP emissions from listed categories of sources. The control of HAP is typically achieved through promulgation of emission standards under sections 112(d) and (f) of the CAA and, in appropriate circumstances, work practice standards under section 112(h) of the CAA.

Section 112(n)(1)(A), which provides the authority for today's proposed section 112 rule, states as follows:

> The Administrator shall perform a study of the hazards to public health reasonably anticipated to occur as a result of emissions by electric utility steam generating units of pollutants listed under subsection (b) after imposition of the requirements of this Act. The Administrator shall report the results of this study to the Congress within 3 years after the date of the enactment of the Clean Air Act Amendments of 1990. The Administrator shall develop and describe in the Administrator's report to Congress alternative control strategies for emissions which may warrant regulation under this section. The Administrator shall regulate electric utility steam generating units under this section, if the Administrator finds such regulation is appropriate and necessary after considering the results of the study required by this subparagraph.

By its express terms, section 112(n)(1)(a) applies only to Utility Units. It establishes certain predicates and requirements that are uniquely applicable to the regulation of Utility Units, and that have not been the subject of previous EPA regulatory decisions under section 112. In the circumstances presented here, and as discussed below, EPA interprets section 112(n)(1)(A) only to authorize the Agency to promulgate section 112 standards for Utility Units with respect to HAP emissions from such units that are reasonably anticipated to result in a hazard to public health after imposition of the other requirements of the CAA. To the extent section 112 can be interpreted as authorizing but not requiring EPA to go beyond that, and to promulgate section 112 standards for HAP emissions that are not reasonably anticipated to result in a hazard to public health, EPA has decided not to do so.

Section 112(n)(1)(a) contains four basic instructions to EPA. First, EPA must prepare a study on "the hazards to public health reasonably anticipated to occur as a result of emissions by electric utility steam generating units of * * * [HAP] * * * after imposition of the requirements of this Act," and submit the results in a report to Congress. Second, EPA must develop alternative control strategies for HAP emissions from Utility Units and describe them in the report. Third, and "after considering the results of the study required by" section 112(n)(1)(A), the EPA may determine whether regulation of Utility Units under section 112 is "appropriate and necessary." Finally, if EPA determines that regulation under section 112 is appropriate and necessary, EPA must promulgate such regulations.

We carried out our obligations with respect to the first of these instructions when we completed and submitted to Congress in February 1998 the Utility RTC. The Utility RTC did not expressly state conclusions about any HAP, other than Hg, that was known to be emitted from coal-fired Utility Units. The RTC also included information indicating that Ni emissions from oil-fired Utility Units are of concern. Additionally, the ICR conducted in 1999 served to collect data and inform the EPA further only with respect to Hg emissions from coal-fired units, the pollutant of greatest concern in the health-based Utility RTC.

The Utility RTC also carried out a portion of the second instruction—the development of alternative control strategies. Later in this notice, we will discuss additional alternative control strategies.

We carried out the third step in the section 112(n)(1)(A) process when, on December 20, 2000, EPA published a "Regulatory Finding on the Emissions of Hazardous Air Pollutants From Electric Utility Steam Generating Units." (65 FR 79825) We determined at that time that it was appropriate to regulate HAP emissions from coal- and oil-fired Utility Units because: (1) Such units "are the largest domestic source of [Hg] emissions, and [Hg] in the environment presents significant hazards to public health and the environment;" and (2) we had "identified a number of control options which EPA anticipates will effectively reduce HAP emissions from such units." *Id.* at 79830. The EPA also found that "regulation of HAP emissions from natural gas-fired electric utility steam generating units is not appropriate or necessary because the impacts due to HAP emissions from such units are negligible based on the results of the study documented in the [U]tility RTC." *Id.* at 79831. We have found no reason to reconsider or revise that finding, and therefore today's proposed section 112 rule does not address gas-fired Utility Units.[5]

Thus, EPA's appropriateness finding in December 2000 focused on the significant health hazards associated with Hg and the availability of control strategies for certain HAP from coal-fired Utility Units. The finding also rested, in part, however, on the uncertainties regarding the public health effects associated with HAP from oil-fired units. Id. Although EPA did not specify in the December 2000 finding which HAP emissions from oil-fired units posed hazards to public health, the record demonstrates that Ni was the HAP of greatest concern from a public health perspective because of the quantities of Ni emitted from oil-fired Utility Units and the scope and number of adverse health effects associated with Ni exposure.

Our December 2000 finding stated that it was necessary to regulate HAP

[5] As EPA stated in the December 2000 finding, it does not believe that the definition of electric utility steam generating unit found in section 112(a)(8) of the Act encompasses stationary combustion turbines. 65 FR 79831. Therefore, today's proposed section 112 regulation does not address stationary combustion turbines. As further discussed elsewhere in this preamble, stationary combustion turbines are covered under the combustion turbine MACT standard.

emissions from coal- and oil-fired Utility Units under section 112 "because the implementation of other requirements under the CAA will not adequately address the serious public health and environmental hazards arising from such emissions identified in the [U]tility RTC and confirmed by the NAS study, and which section 112 is intended to address." *Id.* at 79830.

While the December 2000 finding recounts at length the Agency's analysis and conclusions concerning the health risks from Hg exposure, it does not expressly state findings about health risks that are presented by other HAP emissions from Utility Units.

With today's notice, EPA is proposing to carry out the fourth of the four instructions in section 112(n)(1)(A)—that is, EPA is proposing to regulate Utility Units under section 112. In doing so, a threshold question is presented as to whether EPA must regulate the two HAP that were the primary focus of the step 2 finding, or whether it must regulate emissions of all HAP listed in section 112(b). Section 112(n)(1)(A) provides no express direction to EPA as to the HAP that should be addressed if we determine that regulation of Utility Units under section 112 is appropriate and necessary.

The EPA interprets section 112(n)(1)(A) as only authorizing regulation of Utility Units under section 112 with respect to HAP emissions from such units that EPA has determined are "appropriate and necessary" to regulate under section 112 because they are reasonably anticipated to result in a hazard to public health even after imposition of the other requirements of the CAA. Because EPA's December 2000 determination only made such a finding as to, at most, Hg emissions from coal-fired units and Ni emissions from oil-fired units, today's section 112 proposal only addresses those HAP emissions from the respective units.

As explained above, section 112(n)(1)(A) sets forth a regulatory scheme that is predicated on the completion of a study of hazards to public health. The EPA is to develop and describe in the report "alternative control strategies for emissions which may warrant regulation under this section," and then may determine regulation of the source category "is appropriate and necessary after considering the results of the study." Fairly read, this section requires EPA to narrowly focus any regulation it may promulgate pursuant to this authority. Indeed, an interpretation of section 112(n)(1)(A) that it automatically requires EPA to regulate HAP emissions from Utility Units for which no health hazard had been found would effectively read out of the statute much of the language set forth in this section and render superfluous much of the section 112(n)(1)(A) processes and requirements.

More specifically, the study that EPA is required to perform is to address the "hazards to public health reasonably anticipated to occur as a result of" HAP emissions by Utility Units. The EPA is authorized to regulate under section 112 only if the Agency "finds such regulation is appropriate and necessary *after considering the results of the study required by this subparagraph.*" (Emphasis added.) Because the decision to regulate is expressly linked to the results of the study, it is reasonable to interpret section 112(n)(1)(A) as authorizing EPA to promulgate section 112 emissions regulations for Utility Units only with respect to the HAP that the EPA has determined are appropriate and necessary to regulate under this section. Furthermore, EPA is directed to develop and describe "alternative control strategies for emissions *which may warrant regulation under this section.*" (Emphasis added.) The emphasized phrase signals that an "appropriate and necessary" finding under section 112(n)(1)(A) does not require EPA to regulate emissions of all HAP from Utility Units once an "appropriate and necessary" finding as to at least one HAP has been made. In fact, that phrase has no meaning at all if EPA automatically is required to regulate all HAP from electric utility steam generating units once EPA makes an "appropriate and necessary" finding. The EPA believes the better interpretation of this language is that an appropriate and necessary finding can be made as to emissions of some HAP but not others, and trigger a requirement to promulgate section 112 regulations only as to the specific HAP for which the Agency has made the "appropriate and necessary" finding.

It might be argued that, even though our section 112(n)(1)(A) finding was based on concern about hazards to human health only from particular HAP, that the "under this section" phrase means that once EPA makes an "appropriate and necessary" finding with respect to the emissions of any one HAP, EPA must regulate all HAP listed in CAA section 112(b). That, in fact, is what EPA is required to do with respect to source categories other than Utility Units (*i.e.*, source categories to which section 112(n)(1)(A) does not apply). *See National Lime Association* v. *EPA*, 223 F.3d 625 (D.C. Cir. 2000).

The EPA rejects such an interpretation of section 112(n)(1)(A). As explained above, EPA believes that interpreting section 112(n)(1)(A) in this manner would ignore much of the language set forth in that section, and would render superfluous the section's processes and requirements. By contrast, EPA's interpretation gives meaning to all of the words of section 112(n)(1)(A) and is consistent with requiring regulation under section 112 only of those HAP emissions from Utility Units that are identified as appropriate and necessary to regulate under section 112 because they are reasonably anticipated to result in a hazard to public health after imposition of the other requirements of the CAA.

Our interpretation of section 112(n)(1)(A) is supported by the legislative history of this section. The House version of what became section 112(n)(1)(A) was adopted in lieu of the Senate provision. Senate Bill S. 1630, which contained the version that was not adopted, would have required regulation of HAP from Utility Units under section 112(d), notwithstanding the results of certain mandated studies. The House language, by contrast, did not presume that regulation was needed and certainly did not require that EPA regulate all HAP emissions from Utility Units if it regulated any. "[I]f the Administrator regulates any of these units, he may regulate only those units that he determines—after taking into account compliance with all provisions of the Act and any other Federal, State or local regulation and voluntary emission reductions—have been demonstrated to cause a significant threat of adverse effects on the public health." 136 Cong. Rec. E3670, E3671 (Nov. 2, 1990) (statement of Cong. Oxley).

Finally, even if it is possible to construe section 112(n)(1)(A) as allowing EPA to regulate Utility Unit emissions of all HAP listed in section 112(b) once the EPA has made an "appropriate and necessary" finding under section 112(n)(1)(A) with respect to any one or more HAP, we still believe that the better interpretation and application of that section is for EPA only to regulate HAP emissions that EPA has determined are "appropriate and necessary" to regulate under section 112 after imposition of the other requirements of the CAA. The EPA believes it would not be consistent with the policy Congress established when it enacted a separate section 112(n)(1)(A) for Utility Units, and required EPA to conduct a public health study and make a determination of appropriateness and necessity, for EPA to decide that utilities simply should be subject to the same types of regulation and in the same form as all other sources, despite the lack of any health-based finding that regulation of all HAP is appropriate or necessary. Furthermore, and as discussed elsewhere in this notice, such an interpretation would impose regulatory mandates with no discernable benefit to public health. The EPA is not inclined to impose costly regulatory mandates with no discernable public health benefit in the absence of clear direction by Congress that EPA must do so.

In developing today's proposed section 112 MACT rule, EPA has decided, as one regulatory option, to employ the section 112(d) process and propose a MACT standard. This is the result of EPA's having accompanied its December 2000 finding with a decision to list coal-fired and oil-fired Utility Units under section 112(c) of the CAA (65 FR 79825, 79830, December 20, 2000).

A standard developed pursuant to section 112(d) must reflect the maximum degree of reductions in emissions of HAP that is achievable taking into consideration the cost of achieving emissions reductions, any non-air-quality health and environmental impacts, and energy requirements. This level of control is commonly referred to as MACT. The MACT standards can be based on the emissions reductions achievable through application of measures, processes, methods, systems, or techniques including, but not limited to: (1) Reducing the volume of, or eliminating emissions of, such pollutants through process changes, substitutions of materials, or other modifications; (2) enclosing systems or processes to eliminate emissions; (3) collecting, capturing, or treating such pollutants when released from a process, stack, storage or fugitive emission point; (4) implementing design, equipment, work practices, or operational standards as provided in subsection 112(h) of the Act; or (5) a combination of the above.

For new sources, MACT standards cannot be less stringent than the emission control achieved in practice by the best-controlled similar source. The MACT standards for existing sources can be less stringent than standards for new sources, but they cannot be less stringent than the average emission limitation achieved by the best performing 12 percent of existing sources (for which the Administrator has emissions information) for categories and subcategories with 30 or more sources, or the best-performing 5 sources for categories or subcategories with fewer than 30 sources.

Even though EPA has developed today's proposed section 112 MACT rule pursuant to section 112(d)'s procedures and standards, section 112(n)(1)(A) expressly calls for EPA to develop "alternative control strategies" for the regulation of HAP emissions that "may warrant regulation" under section 112. In addition, section 112(n)(1)(A) specifies that any regulation should be "appropriate and necessary" in light of "hazards to public health reasonably expected to occur"—a departure from the traditional section 112(d) approach applicable to other types of sources. As set forth in the second part of today's notice, EPA is proposing to revise the December 2000 regulatory finding, to remove coal- and oil-fired Utility Units from the section 112(c) list, and instead to regulate Hg emissions from coal-fired Utility Units and Ni emissions from oil-fired units pursuant to existing authority in section 111 of the Act.

But as an alternative to revising the December 2000 finding and regulating under section 111, EPA believes it also has authority to leave the December 2000 "appropriate and necessary" finding in place, and to proceed to regulate under section 112(n) of the Act. In that event, EPA could promulgate, under section 112(n)(1)(A), a cap-and-trade program for Hg somewhat like the one that EPA is today proposing pursuant to CAA section 111. Therefore, and as another alternative, EPA also is proposing in today's notice to remove coal-fired Utility Units from the section 112(c) list, and to promulgate pursuant to section 112(n)(1)(A) a cap-and-trade program for Hg from coal-fired Utility Units.

In implementing this program under section 112, EPA would adopt a cap that reflects the projected Hg emissions that would occur under the section 112 MACT approach, which EPA currently projects to be 34 tons per year under the MACT proposal set forth in today's notice. The EPA would apportion this cap level of annual emissions across coal-fired units using the proposed MACT emission limits presented in Tables 1 and 2 and the proportionate share of their baseline heat input to total heat input of all affected units. Alternatively, EPA would apportion this cap level of annual emissions across all coal-fired Utility Units in accordance with the emission guidelines associated with the section 111 cap-and-trade proposal, contained in today's proposal. The EPA would implement a MACT cap-and-trade rule using a model trading rule similar to the model rule that we would use for our section 111 trading proposal. The EPA explains below its interpretation of CAA section 112 and why these trading approaches are permissible under section 112, and solicits comment on these approaches.

Section 112(n), which is quoted in part above, provides EPA's authority to regulate HAP emissions from Utility Units. By its express terms, section 112(n)(1)(A) applies only to such units and establishes certain predicates and requirements that are uniquely applicable to the regulation of this source category. In the typical cases of regulating HAP from other source categories, EPA's regulatory authority is derived from section 112(d), which prescribes a relatively rigid, plant-by-plant, MACT approach. By contrast, section 112(n) can be interpreted to authorize a more flexible, risk-based approach; there is nothing in section 112(n)(1)(A) that requires an "appropriate and necessary" finding to result in a section 112(c) listing or regulation under section 112(d).

While section 112(d) mandates regulation of all HAP emissions based on the emissions limitations achieved by similar sources, section 112(n) calls for regulation of Utility Unit HAP emissions as EPA determines is "appropriate and necessary after considering the results of the study" of public health hazards reasonably anticipated to occur from those Utility Unit HAP emissions. Congress provided EPA with distinct regulatory authority to address HAP emissions from Utility Units "because of the logic of basing any decision to regulate on the results of scientific study and because of the emission reductions that will be achieved and the extremely high costs that electric generators will face under other provisions of the new Clean Air Act Amendments." 136 Cong. Rec. E3670, E3671 (Nov. 2, 1990) (statement of Cong. Oxley).

Congress's intent to authorize EPA to regulate Utility Unit HAP emissions in ways other than with the prescriptive requirements of section 112(d) is indicated by the section 112(n) requirement that EPA develop alternative control strategies for HAP emissions from these units. These alternative control strategies must address the hazards to public health that EPA reasonably anticipates will occur as a result of Utility Unit HAP emissions. Congress authorized EPA to consider a wider range of control alternatives for the utility sector than the source-by-source approach EPA has prescribed in standards for other source categories under the traditional section 112(d) MACT approach. Because Congress directed EPA to develop control strategies that would be alternatives to the usual section 112(d) MACT standard, it is reasonable to conclude that Congress authorized EPA to implement such alternatives.

As a result, EPA believes that section 112(n) confers on the Agency the authority to develop a system-wide or pooled performance standard for HAP emissions from Utility Units. Notably, in the December 2000 section 112(n)(1)(A) finding, we identified the "considerable interest in an approach to Hg regulation for power plants that would incorporate economic incentives such as emissions trading." 65 FR at 79830. We also offered the conclusion that "[r]ecent data * * * indicate the possibility for multipollutant control with other pollutants (*e.g.*, NO_X, SO_2, and PM), greatly reducing mercury control costs."

In addition, section 112(n)(1)(A) specifies that any regulation of HAP emissions from Utility Units should be "appropriate and necessary" in light of "hazards to public health reasonably anticipated to occur"—a departure from the traditional 112(d) approach applicable to other types of sources. Read as a whole, section 112(n)(1)(A) could be read to grant authority to develop and propose different control mechanisms than might be required under the section 112(d) approach. Under this reading, EPA could adopt any control strategy that is "appropriate and necessary" in light of "hazards to public health reasonably anticipated to occur."

As discussed at length elsewhere in today's notice, a trading approach for Utility Unit emissions of Hg has many advantages over a prescriptive, technology-based approach such as a MACT. *See* discussion, *infra,* section IV(D). We also reiterate that a cap and trade approach to controlling Hg emissions dovetails well with our proposal concerning an IAQR. *See* discussion, *infra,* section IV. Accordingly, a trading approach for Hg is consistent with Congress's direction in section 112(n)(1)(A) that any EPA regulation of HAP emissions from Utility Units must take into account compliance by those units with regulations and emissions reductions under other provisions of the CAA.

In past MACT rulemakings and with respect to source categories other than Utility Units, EPA has not resolved whether a system-wide or pooled performance standard is permitted under section 112(d). However, EPA has under the authority of section 112(d) established affected source-wide emissions averaging provisions that do not necessarily require each regulated source to apply controls. The EPA requests comment on whether we can expand upon this idea and establish a program similar to the program we believe could be promulgated pursuant to section 112(n), including system averaging, based on section 112(d). If EPA concludes that nothing in section 112(d) precludes this result, that section could provide a basis for EPA's final rule.

We note that implementing a cap and trade rule for Utility Units under section 112 could offer certain advantages as compared to our proposed section 111 approach. For example, EPA should be able to directly implement a national standard under section 112, instead of relying on the SIP-type approach required under section 111. As a result, a section 112 trading program would, among other things, reduce the administrative burdens on both EPA and the States and would assure national consistency.

The EPA invites public comment on all aspects of implementing a trading program under section 112. The EPA also requests comment on how it should design a trading program under section 112, including whether the title IV Acid Rain SO_2 program, the Acid Rain NO_X program, the NO_X SIP Call or today's proposed section 111 trading program are useful models for regulating Hg emissions.

In conjunction with this proposal to establish a cap-and-trade program under the authority of section 112(n)(1)(A) and/or 112(d), we also propose to revise the definition of "emission standard" in 40 CFR 63.2. We propose to amend the phrase "pursuant to sections 112(d), 112(h), or 112(f) of the Act" to include reference to section 112(n).

B. Summary of the Proposed Section 112 MACT Rule

1. What Is the Affected Source?

An existing affected source for the proposed rule is each group of coal- or oil-fired Utility Units located at a facility. A new affected source is a coal- or oil-fired Utility Unit for which construction or reconstruction began after January 30, 2004. The proposed rule defines a Utility Unit as:

> a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is also an electric utility steam generating unit.

If a unit burns coal (either as a primary fuel or as a supplementary fuel), or any combination of coal with another fuel, the unit is considered to be coal-fired under the proposed rule. If a unit is not a coal-fired unit and burns only oil, or oil in combination with natural gas (except as noted below), the unit is considered to be oil-fired under the proposed rule. If a new or existing unit burns natural gas exclusively or natural gas in combination with oil where the oil constitutes less than 2 percent of the unit's annual fuel consumption (used for start-up purposes), the unit is considered to be natural gas-fired and would not be subject to the proposed rule.

2. What Are the Proposed Emission Limitations?

The proposed rule would establish separate emissions limits for new and existing coal- and oil-fired Utility Units. For coal-fired units, limits would be established for Hg depending on the rank of coal. For oil-fired units, limits would be established for Ni emissions. The proposed limits for Hg for coal-fired units are expressed in pound per trillion British thermal unit (lb/TBtu) on an input basis or pound per Megawatt hour (lb/MWh) on an output basis. The proposed Ni limits for oil-fired units are expressed in lb/TBtu on an input basis or lb/MWh on an output basis. For both Hg and Ni, owners/operators of existing units would have the option of complying with either the input- or the output-based limit; owners/operators of new units would be subject to the output-based limit. The owner/operator would establish a unit-specific limit (according to methods provided in the proposed rule) for each coal-fired unit that burns blended coal. The proposed limits for coal-fired and oil-fired units are shown in Tables 1 and 2, respectively, of this preamble (for existing affected sources) and Tables 3 and 4, respectively, of this preamble (for new affected sources).

TABLE 1.—EMISSION LIMITS FOR EXISTING COAL-FIRED ELECTRIC UTILITY STEAM GENERATING UNITS

Unit type	Hg (lb/TBtu) [1]		Hg (10^{-6} lb/MWh) [1]
Bituminous-fired [2]	2.0	or	21
Subbituminous-fired	5.8	or	61
Lignite-fired	9.2	or	98
IGCC unit	19	or	200
Coal refuse-fired	0.38	or	4.1

[1] Based on 12-month rolling average.

[2] Anthracite units are included with bituminous units.

TABLE 2.—EMISSION LIMITS FOR EXISTING OIL-FIRED ELECTRIC UTILITY STEAM GENERATING UNITS

Unit type	Ni (lb/TBtu) [1]		Ni (lb/MWh) [1]
Oil-fired ..	210	or	0.002

[1] Based on do-not-exceed limit.

TABLE 3.—EMISSION LIMITS FOR NEW COAL-FIRED ELECTRIC UTILITY STEAM GENERATING UNITS

Unit type	Hg (10^{-6} lb/MWh) [1]
Bituminous-fired [2]	6.0
Subbituminous-fired	20
Lignite-fired	62
IGCC unit	[3] 20
Coal refuse-fired	1.1

[1] Based on 12-month rolling average.
[2] Anthracite units are included with bituminous units.
[3] Based on 90 percent reduction for beyond-the-floor control.

TABLE 4.—EMISSION LIMITS FOR NEW OIL-FIRED ELECTRIC UTILITY STEAM GENERATING UNITS

Unit type	Ni (lb/MWh) [1]
Oil-fired	0.0008

[1] Based on do-not-exceed limit.

Two alternatives for compliance purposes are provided in the proposed rule for oil-fired units. The owner/operator can elect to: (1) meet the Ni limit, or (2) burn distillate oil (exclusively) rather than residual oil. If an oil-fired unit is currently burning, or switches to burning, distillate oil (exclusively), it would be exempt from all oil-fired unit initial and continuous compliance requirements until such time as it begins burning any oil other than distillate oil. The proposed rule would require that the exempted oil-fired unit begin the performance testing procedures if it resumes burning a fuel other than distillate oil.

The proposed rule would also allow emissions averaging as a compliance option for existing coal-fired units located at a single contiguous plant. The owner/operator could elect to establish an overall Hg limit for an emissions averaging group using the procedures in the proposed rule and comply with that limit during each 12-month compliance period. The emissions averaging compliance approach is also applicable to coal-fired Utility Units subject to the Hg emission limits for new affected sources as long as they meet the new source limits.

The proposed emission limitations also include operating limits for control devices used to meet an emissions limitation. If an electrostatic precipitator (ESP) is used to meet a Ni limit, the owner/operator would be required to operate each ESP such that the hourly average voltage and secondary current (or total power input) do not fall below the limit established in the most recent performance test. Operating limits would not apply to control devices used to meet Hg emission limits where a continuous emission monitoring system (CEMS) or an appropriate long-term method is used to demonstrate compliance.

3. What Are the Proposed Testing and Initial Compliance Requirements?

New or reconstructed units must be in compliance with the applicable rule requirements upon initial startup or by the effective date of the final rule, whichever is later. Existing units must be in compliance with the applicable rule requirements no later than 3 years after the effective date of the final rule. The effective date is the date on which the final rule is published in the **Federal Register**.

Prior to the compliance date, the owner/operator would be required to prepare a unit-specific monitoring plan and submit the plan to the Administrator for approval. The proposed rule would require that the plan address certain aspects with regard to the monitoring system; installation, performance and equipment specifications; performance evaluations; operation and maintenance procedures; quality assurance techniques; and recordkeeping and reporting procedures. Beginning on the compliance date, the owner/operator would be required to comply with the plan requirements for each monitoring system.

Mercury emission limits. Compliance with the Hg emission limit would be determined based on a rolling 12-month average calculation. The Hg emissions are determined by continuously collecting Hg emission data from each affected unit by installing and operating a CEMS or an appropriate long-term method that can collect an uninterrupted, continuous sample of the Hg in the flue gases emitted from the unit. The proposed rule would allow the owner/operator to use any CEMS that meets requirements in Performance Specification 12A (PS–12A), "Specifications and Test Procedures for Total Vapor-phase Mercury Continuous Monitoring Systems in Stationary Sources." An owner/operator electing to use long-term Hg monitoring would be required to comply using the new EPA Method 324, "Determination of Vapor Phase Flue Gas Mercury Emissions from Stationary Sources Using Dry Sorbent Trap Sampling." Performance Specification 12A and Test Method 324 are proposed as part of this rulemaking. The owner/operator would use the procedures outlined in § 63.10009 of the proposed rule to convert the concentration output from a CEMS or Method 324 to an emission rate format in lb/TBtu or lb/MWh. The proposed rule would require the owner or operator to begin compliance monitoring on the compliance date.

For new or existing cogeneration units, steam is also generated for process use. The energy content of this process steam must also be considered in determining compliance with the output-based standard. Therefore, the owner/operator of a new or existing cogeneration unit would be required to calculate emission rates based on electrical output to the grid plus half the equivalent electrical output energy in the unit's process steam. The procedure for determining these Hg emission rates is included in § 63.10009(c) of the proposed rule.

The owner/operator of a new or existing coal-fired unit that burns a blend of fuels would develop a unit-specific Hg emission limitation and the unit Hg emission rate for the portion of the compliance period that the unit burned the blend of fuels. The procedure for determining these emission limitations is outlined in § 63.9990(a)(5) of the proposed rule.

Nickel emission limits. Compliance with the applicable Ni emission limits in the proposed rule would be determined by performance tests conducted according to the requirements in 40 CFR 63.7 of the NESHAP General Provisions and the requirements in the proposed rule. The proposed rule would require EPA Method 29 in appendix A to 40 CFR part 60 to be used for the measurement of Ni emissions in the flue gas. With Method 29, Method 1 would be used to select the sampling port location and the number of traverse points; Method 2 would be used to measure the volumetric flow rate; Method 3 would be used for gas analysis; and Method 4 would be used to determine stack gas moisture. Method 19 would be used to convert the Method 29 Ni measurements to an emission rate expressed in units of lb/TBtu if complying with an input-based standard. The owner/operator would use the procedures outlined in § 63.10009 of the proposed rule to convert the concentration output of

Method 29 to an emission rate format in lb/TBtu or lb/MWh.

The proposed rule would require the owner/operator to establish limits for control device operating parameters based on the actual values measured during each performance test. The proposed rule specifies the parameters to be monitored for the types of emission control systems commonly used in the industry. The owner/operator would be required to submit a monitoring plan identifying the operating parameters to be monitored for any control device used that is not specified in the proposed rule.

An initial performance test to demonstrate compliance with each applicable Ni emission limit would be required no later than 180 days after initial startup or 180 days after publication of the final rule, whichever is later, for a new or reconstructed unit, and no later than the compliance date for an existing unit (3 years after publication of the final rule).

The owner/operator of a new or existing cogeneration unit would have to account for the process steam portion of their emissions in the same manner for Ni emissions as they did for Hg emissions. The owner/operator of a cogeneration unit would be required to calculate the Ni emission rate based on electrical output to the grid plus half the equivalent electrical output energy in the unit's process steam (*see* section II.C.2 for an explanation of the basis for this approach). The procedure for determining these Ni emission rates are given in § 63.10009(c) of the proposed rule.

4. What Are the Proposed Continuous Compliance Requirements?

To demonstrate continuous compliance with the applicable emission limits under the proposed rule, the owner/operator would be required to perform continuous Hg emission monitoring for coal-fired units and continuous monitoring of appropriate operating parameters for the ESP used to comply with the Ni limit for oil-fired units. In addition, an annual performance test will be required for demonstrating compliance with the Ni emission limitation for oil-fired units. The annual performance test would be conducted in the same manner as the initial compliance demonstration.

5. What Are the Proposed Notification, Recordkeeping, and Reporting Requirements?

The proposed rule would require the owner/operator to keep records and file reports consistent with the notification, recordkeeping, and reporting requirements of the General Provisions of 40 CFR part 63, subpart A. Records required under the proposed rule would be kept for 5 years, with the 2 most recent years being on the facility premises. These records would include copies of all Hg emission monitoring data, coal usage, MWh generated, and heating value data required for compliance calculations; reports that have to be submitted to the responsible authority; control equipment inspection records; and monitoring data from control devices demonstrating that emission limitations are being maintained.

Two basic types of reports would be required: initial notifications and periodic reports. The owner/operator would be required to submit notifications described in the General Provisions (40 CFR part 63, subpart A), which include initial notification of applicability, notifications of performance tests, and notification of compliance status. For oil-fired units, if you at any time during the reporting period comply with an applicable emissions limit by switching fuel (in other than emergency situations), the proposed rule would also require that you notify EPA in writing at least 30 days prior to using a fuel other than distillate oil. In emergency situations, such notification must be within 30 days. As required by the General Provisions, the owner/operator would be required to submit a report of performance test results; develop and implement a written startup, shutdown, and malfunction plan and report semi-annually any events in which the plan was not followed; and submit semi-annual reports of any deviations when any monitored parameters fell outside the range of values established during the performance test.

C. Rationale for the Proposed Section 112 MACT Rule

1. How Did EPA Select the Affected Sources That Would Be Regulated Under the Proposed Rule?

As defined in section 112(a)(8) of the CAA, an "electric utility steam generating unit" means "any fossil fuel fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale. A unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 megawatts electrical output to any utility power distribution system for sale shall be considered an electric utility steam generating unit." For purposes of this proposed standard, any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy gross output capacity of the affected facility.

Only Utility Units that are fired by coal or oil, or combinations of fuels that include coal and oil, are subject to this proposal. Integrated gasification combined cycle units are also subject to this proposal. Boilers otherwise meeting the definition but fueled by gaseous fuels (other than gasified coal) at greater than or equal to 98 percent of their annual fuel consumption (when the other fuel burned is fuel oil or coal) are not included in the proposed rule.

An affected source under MACT is the equipment or collection of equipment to which the MACT rule limitations or control technology is applicable. For the proposed rule, the affected source would be the group of coal- or oil-fired units at a facility (a contiguous plant site where one or more Utility Units are located). Each unit would consist of the combination of a furnace firing a boiler used to produce steam, which is in turn used for a steam-electric generator that produces electrical energy for sale. This definition of affected source would include a wide range of regulated units with varying process configurations and emission profile characteristics.

Therefore, the first step towards rule development is to determine if dissimilarities between sources within the source category warrant subcategorization. Under CAA section 112(d)(1), which EPA is proposing to use for purposes of developing this rule pursuant to CAA section 112(n)(1)(A), the Administrator has the discretion to "* * * distinguish among classes, types, and sizes of sources within a category or subcategory in establishing * * *" standards.

Historically and as EPA noted in the December 2000 finding, the criteria used by EPA in evaluating differences in combustion sources for purposes of subcategorization have included the size of the facility, type of fuel used, and plant type. (65 FR 79830) The EPA also is free to consider other relevant factors, such as geographic factors, process design or operation, variations in emissions profiles, or differences in the feasibility of application of control technology (APCD or work practices).

For the coal- and oil-fired Utility Unit source category, the individual units or sources exhibited obvious and significant variations with regard to some of these criteria. The most prominent dissimilarity was that between coal- and oil-fired units. Coal- and oil-fired units have vastly different emission characteristics due to their different fuels. The electric utility industry generally uses coal-fired units as base-loaded units (*i.e.*, the units are designed to run continuously except for maintenance intervals). Oil-fired units are generally used as "peaking" units (*i.e.*, the units are operated when extra electrical power is needed). Coal combustion produces higher emission levels of Hg than does a comparably sized oil-fired unit whereas oil combustion produces higher levels of Ni compounds. For these reasons, EPA divided sources into the initial subcategories of coal- and oil-fired units. Additional evaluation of the data was then conducted to ascertain if further subcategorization within coal-fired or within oil-fired units was warranted.

Subcategorization within existing coal-fired units. The American Society for Testing and Materials (ASTM) classifies coals by rank, a term which relates to the carbon content of the coal and other related parameters such as volatile-matter content, heating value, and agglomerating properties. The coal-fired electric utility industry combusts the following coal ranks, presented in decreasing order: anthracite, bituminous, subbituminous, and lignite. The higher heating value (HHV) of coal is measured as the gross calorific value, reported in British thermal units per pound (Btu/lb). The heating value of coal increases with increasing coal rank. The youngest, or lowest rank, coals are termed lignite. Lignites have the lowest heating value of the coals typically used in power plants. Their moisture content can be as high as 30 percent, but their volatile content is also high; consequently, they ignite easily. Next in rank are subbituminous coals, which also have a relatively high moisture content, typically ranging from 15 to 30 percent. Subbituminous coals also are high in volatile matter content and ignite easily. Their heating value is generally in between that of the lignites and the bituminous coals. Bituminous coals are next in rank, with higher heating values and lower moisture and volatile content than the subbituminous and lignite coals. Anthracites are the highest rank coals. Because of the difficulty in obtaining and igniting anthracite and the difficulties in maintaining anthracite-fired boilers, only a single electric utility boiler in the U.S. burned anthracite as its only fuel in 1999. Because bituminous coal is the most similar coal to anthracite coal based on coal physical characteristics (ash content, sulfur content, HHV), anthracite coal is considered to be equivalent to bituminous coal for the purposes of the proposed rule and, thus, the anthracite-fired unit is considered a bituminous-fired unit for the purposes of the proposed rule.

Although there is overlap in some of the ASTM classification properties, the ASTM method of classifying coals by rank has been in use for decades and generally is successful in identifying some common core characteristics that have implications for power plant design and operation.

Coal refuse (*i.e.*, anthracite coal refuse (culm), bituminous coal refuse (gob), and subbituminous coal refuse) is also combusted in Utility Units. Coal refuse refers to the waste products of coal mining, physical coal cleaning, and coal preparation operations (*e.g.* culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material. Previously considered unusable by the industry because of the high ash content and relatively low heat content, it now may be utilized as a supplemental fuel in limited amounts in some units or as the primary fuel in a fluidized bed combustor (FBC). Because of the inherent inability to utilize coal refuse as the primary fuel in anything other than an FBC, it is considered to be a separate coal rank for purposes of the proposed rule.

The rank of coal to be burned has a significant impact on overall plant design. The goal of the plant designer is to arrange boiler components (furnace, superheater, reheater, boiler bank, economizer, and air heater) to provide the rated steam flow, maximize thermal efficiency, and minimize cost. Engineering calculations are used to determine the optimum positioning and sizing of these components, which cool the flue gas and generate the superheated steam. The accuracy of the parameters specified by the owner/operators is critical to designing and building an optimally efficient plant. The rank of coal to be burned greatly impacts the entire design process. The rank of coal burned also has significant impact on the design and operation of the emission control equipment (*e.g.*, ash resistivity impacts ESP performance).

For the above reasons, one of the most important factors in modern electric utility boiler design involves the differences in the ranks and range of coals to be fired and their impact on the details and overall arrangement of boiler components. Coal rank is so important that plant designers and manufacturers expect to be provided with a complete list of all coal ranks presently available or planned for future use, along with their complete chemical and ash analyses, so that the engineers can properly design and specify plant equipment. The various coal characteristics (*e.g.*, how hard the coal is to pulverize; how high its ash content; the chemical content of the ash; how the ash "slags" (fused deposits or resolidified molten material that forms primarily on furnace walls or other surfaces exposed predominantly to radiant heat or high temperature); how big the boiler has to be to adequately utilize the heat content; etc.), therefore, affect design from the pulverizer through the boiler to the final steam tubes. For a boiler to operate efficiently, it is critical to recognize the differences in coals and make the necessary modifications in boiler components during design to provide optimum conditions for efficient combustion.

Coal-fired units are designed and constructed with different process configurations partially because of the constraints, including the properties of the fuel to be used, placed on the initial design of the unit. Accordingly, these site-specific constraints dictate the process equipment selected, the component order, the materials of construction, and the operating conditions.

Approximately 23 percent of coal-fired Utility Units either (1) co-fire two or more ranks of coal (with or without other fuels) in the same boiler, or (2) fire two or more ranks of coal (with or without other fuels) in the same boiler at different times (1999 EPA ICR). This coal "blending" is done generally for one of three reasons: (1) to achieve SO_2 emission compliance with title IV provisions of the CAA, (2) to prevent excessive slagging by improving the heat content of a lower grade coal, or (3) for economic reasons (*i.e.*, coal rank price and availability).

These blended coals, although of different rank, do have similar properties. That is, because of the overlap in various characteristics in the ASTM definitions of coal rank, certain bituminous and subbituminous coals (for example) exhibit similar handling and combustion properties. Plant designers and operators have learned to accommodate these blends in certain circumstances without significant impact on plant operation or control.

There are five basic types of coal combustion processes used in the coal-fired electric utility industry. These are conventional-fired boilers, stoker-fired boilers, cyclone-fired boilers, IGCC units, and FBC units.

Conventional boilers, also known as pulverized coal (PC) boilers, have a number of firing configurations based on their burner placement. The basic characteristic that all conventional boilers have in common is that they inject PC and primary air through a burner where ignition of the PC occurs, which in turn creates an individual flame. Conventional boilers fire through many such burners mounted in the furnace walls.

In stoker-fired boilers, fuel is deposited on a moving or stationary grate or spread mechanically or pneumatically from points usually 10 to 20 feet above the grate. The process utilizes both the combustion of fine coal powder in air and the combustion of larger particles that fall and burn in the fuel bed on the grate.

Cyclone-fired boilers use several water-cooled horizontal burners that produce high-temperature flames that circulate in a cyclonic pattern. The burner design and placement cause the coal ash to become a molten slag that is collected below the furnace.

Fluidized bed combustors combust coal, in a bed of inert material (*e.g.*, sand, silica, alumina, or ash) and/or a sorbent such as limestone, that is suspended through the action of primary combustion air distributed below the combustor floor. "Fluidized" refers to the state of the bed of material (coal and inert material (or sorbent)) as gas passes through the bed. As the gas flow rate is increased, the force on the fuel particles becomes just sufficient to cause buoyancy. The gas cushion between the solids allows the particles to move freely, giving the bed a liquid-like (or fluidized) characteristic.

Integrated-coal gasification combined cycle units are specialized units in which coal is first converted into synthetic coal gas. In this conversion process, the carbon in the coal reacts with water to produce hydrogen gas and carbon monoxide (CO). The synthetic coal gas (syngas) is then combusted in a combustion turbine which drives an electric generator. Hot gases from the combustion turbine then pass through a waste heat boiler to produce steam. This steam is fed to a steam turbine connected to a second electric generator.

After examining a number of possible subcategorization options, EPA identified three basic ways to subcategorize coal-fired Utility Units.

No subcategorization. This approach would treat all coal ranks and all coal combustion process types as one, with the MACT floor developed using all of the coal-fired unit data.

Subcategorization by coal rank. Subcategorization by individual coal rank accommodates the various design and control constraints resulting from the various coal ranks.

Subcategorization by process type. Another option is to subcategorize by process type (*e.g.*, stoker-fired, cyclone-fired, FBC, IGCC).

To determine the appropriate subcategorization approach, the EPA evaluated fuel, process, and control technology and found that the data did not identify any common attribute among the top units that could be credited with the demonstrated better performance. The EPA found that each of the best-performing units had a combination of factors that was the basis for the better performance on that particular unit. The factors identified included the Hg and chlorine (Cl) contents of the coal, the speciation of the Hg in the flue gas stream, and the control device configuration.

Based on this information, EPA then analyzed the available data to determine which coal ranks were burned, and why, to ascertain if changing coal rank would be a conceivable control strategy. The EPA found that the characteristics of the coal rank to be burned was the driving factor in how a coal-fired unit was designed. Further, the choice of coal ranks to be burned for a given unit is based on economic issues, including availability of the coal within the region or locale. A number of coal-fired units, including all known lignite-fired units, are "mine mouth" (or near mine-mouth) operations (*i.e.*, the unit is constructed on or near the coal mine itself with coal transport often being done by conveyor directly from the mine) and many do not have the infrastructure in place (*e.g.*, interstate rail lines) to import other ranks of coal in quantities sufficient to replace all lignite coal combusted. The EPA also found that substitution of coal rank, in most cases, would require significant modification or retooling of a unit, which would indicate a pertinent difference in the design/operation of the units. Because not all units are designed to combust the same rank of coal and the Hg emissions from some ranks of coal are easier to control than those from other ranks, a standard based on "no subcategorization" likely would be unachievable for some units. For these reasons, EPA decided that subcategorization of coal-fired units based on coal rank (fuel type) was warranted. We note again that certain Utility Units are, in fact, able to effectively combust coals from different ASTM ranks because of the overlap in coal classification properties. We do not, however, believe that this "overlap" compromises our ability to subcategorize by coal rank because it remains true that coal rank is a significant factor that distinguishes the design and operational characteristics of different boilers. We ask for comment on this issue.

Although conventional-, stoker-, and cyclone-fired boilers use different firing techniques, the Hg emissions characteristics of these boilers are similar (when common ranks of coal are fired) and, therefore, the units can be grouped together and further subcategorization by these process types is not necessary.

Based on their unique firing designs, FBC units employ a fundamentally different process for combusting coal from that employed by conventional-, stoker-, or cyclone-fired boilers. Fluidized-bed combustors are capable of combusting many coal ranks, including coal refuse. For these reasons, FBC units can be considered a distinct type of boiler. However, the Hg emissions test data results for FBC units were not substantially different from those at similarly-fueled conventionally-fired units with similar emission levels, either in mass of emissions or in emissions characteristics. Therefore, EPA has decided not to establish a separate subcategory for FBC units.

Integrated gasification combined cycle units combust a synthetic coal gas. No coal is directly combusted in the unit during operation (although a coal-derived fuel is fired), and, thus, IGCC units are a distinct class or type of boiler for the proposed rule.

For the purposes of the proposed rule and based on the above information, the coal-fired units at existing affected sources are subcategorized into five subcategories, four based on coal rank and one based on process type: bituminous (including anthracite); subbituminous; lignite; coal refuse (which includes anthracite coal refuse (culm), bituminous coal refuse (gob), and subbituminous coal refuse); and IGCC (coal syngas). Because few units fire anthracite coal and because there are significant similarities in the emissions resulting from the combustion of anthracite and bituminous coals, EPA chose to combine anthracite coal with bituminous coal for the purposes of this rule. A more detailed description of the specific elements and rationale used to determine this subcategorization scheme is located in the docket.

Subcategorization within existing oil-fired units. The EPA analyzed the data available on the fuel, process, emission profiles, and APCD for oil-fired units at existing affected sources. An oil-fired electric utility boiler combusts fuel oil exclusively, or combusts fuel oil at certain times of the year and natural gas at other times (not simultaneously). The choice of when to combust oil exclusively or to alternate between oil and natural gas at a single boiler is usually based on economics or fuel availability (including seasonal availability). The ASTM classifies oils by "grade," a term which relates to the amount of refinement that the oil undergoes. The level of refinement directly affects the Ni and carbon content of the oil and other related parameters such as sulfur content, heating value, and specific gravity. The most refined fuel oil used by the oil-fired electric utility industry is known as No. 2 fuel oil (also known as distillate oil or medium domestic fuel oil). The least refined fuel oil used by the oil-fired electric utility industry is known as No. 6 fuel oil (also known as residual oil or Bunker C oil). By comparison, No. 2 fuel oil is lower in Ni, sulfur, ash content, and heating value but higher in carbon content than No. 6 fuel oil. Only a handful of boilers (8 of 218) fire No. 2 distillate fuel oil exclusively. (2001 EIA data) However, 28 out of 218 boilers fire No. 2 distillate fuel oil and No. 6 (residual) fuel oil in the same boiler (either simultaneously or at separate times).

The type of oil to be burned has little impact on overall boiler design. The goal of the plant designer is to make sure the plant can handle the different viscosities of oil (and natural gas if applicable) that the boiler is likely to combust.

There is only one basic type of oil combustion process used in the oil-fired electric utility industry, known as a conventional-fired boiler. Conventional-fired boilers have a number of firing configurations based on their burner placement. The basic characteristic that all conventional-fired boilers have in common is that they inject oil and primary air through a burner where ignition of the oil occurs, which in turn creates an individual flame. Conventional-fired boilers fire through many such burners mounted in the furnace walls.

The data available to EPA indicated that there is very little variation in the process or control technologies used in the industry. Therefore, EPA found no criteria that would warrant further subcategorization within existing oil-fired units and is not doing so in the proposed rule.

Subcategorization within new units. With regard to new sources, EPA has no data that indicate that the rationale for subcategorization for existing coal-fired units would not be applicable to new units (*i.e.*, there is no reason to believe that new units will not utilize the full range of coal ranks and combustion process types currently used by existing units). New units constructed at the same facilities as existing units could still be restricted, at least in concept, to the same physical constraints (*e.g.*, coal handling and processing, access to interstate rail lines) as are the co-located existing units. Further, EPA has no data indicating the availability of existing coal ranks is likely to substantially change for a given locale. For this reason, EPA is proposing that the subcategorization scheme for new coal- and oil-fired units be the same as for the existing units.

The EPA solicits comment on this decision that new and existing units should be subcategorized in the same manner.

2. How Did EPA Select the Format of the Proposed Emission Standards?

The EPA has established pollution prevention as one of the its highest priorities. One of the opportunities for pollution prevention lies in simply using energy efficient technologies to minimize the generation of emissions. The EPA has previously investigated ways to promote energy efficiency in utility plants by changing the manner in which it regulates flue gas emissions. Therefore, in an effort to promote energy efficiency in utility steam generating facilities, the Administrator is proposing output-based standards for new sources for emissions of Hg and Ni under this rule. This format has been used successfully on other EPA rules (*e.g.*, subpart Da NSPS NO_X, 40 CFR 63.44a). Existing sources would have the option of using either input- or output-based limits based on the potential increase in cost resulting from the need to add instrumentation.

Traditionally, utility emissions have been controlled on the basis of boiler input energy (lb/million British thermal units (MMBtu) heat input). However, input-based limitations allow units with low operating efficiency to emit more per megawatt (MWe) of electricity produced than more efficient units. Considering two units of equal capacity, under current regulations, the less efficient unit will emit more because it uses more fuel to produce the same amount of electricity. One way to regulate mass emissions and plant efficiency is to express the emission standard in terms of output energy. Thus, an output-based emission standard would provide a regulatory incentive to enhance unit operating efficiency and reduce emissions. Two of the possible output-based formats considered for the revised standards were: (1) Mass emitted per gross boiler steam output (lb/TBtu heat output), and (2) mass emitted per net energy output (lb/MWh). The criteria used for selecting the format were ease in monitoring and compliance testing and ability to promote energy efficiency.

The objective of an output-based standard is to establish an emission limit in a format that incorporates the effects of plant efficiency. Additionally, the limit should be in a format that is practical to implement. Thus, the format selected must satisfy the following: (1) Provide flexibility in promotion of plant efficiency; (2) permit measurement of parameters related to stack emissions and plant efficiency, on a continuous basis; and (3) be suitable for equitable application on a variety of power plant configurations.

The option of lb/TBtu steam output accounts only for boiler efficiency, ignores both the turbine cycle efficiency and the effects of energy consumption internal to the plant, and provides minimal opportunities for promoting energy efficiency at the units. The EPA has found that the second output-based format option of lb/MWh is preferable as it accounts for all aspects of efficiency and provides opportunity for promoting energy efficiency for the units.

The format of lb/MWh can be measured in two ways: net and gross energy output. The net plant energy output provides the owners/operators with all possible opportunities for promoting energy efficiency and can easily accommodate both electrical and thermal (process steam) outputs. The disadvantage of a net plant energy output is that implementation could require significant and costly additional monitoring and reporting systems because the energy output that is used for internal components (and not sent to the grid) cannot be accounted for by simply installing another meter. The gross plant energy output, on the other hand, represents the energy generated before any internal energy consumption and losses are considered. Rules based on this format do not have the disadvantages of the net-based format mentioned above.

Based on this analysis, an emission limit format based on mass of emissions per gross plant energy output is selected for the proposed output-based standard. Because electrical output at all power plants is typically measured directly in MWe, a format in "lb/MWh gross" is determined to be the most appropriate for the proposed rule. The EPA, however, requests comments on the selected format of "lb/MWh gross" because a format of "lb/MWh net" may be more productive in encouraging overall energy efficiency at electric utility plants.

Compliance with the output-based emission limit would require continuous measurement of plant operating parameters associated with the mass rate of emissions and gross energy outputs. In the case of cogeneration plants where process steam is an output product, means would have to be provided to measure the process steam flow conditions and to determine the useful heat energy portion of the process steam that is interchangeable with electrical output.

Instrumentation already exists in power plants to conduct these measurements since the instrumentation is required to support current emission regulations and normal plant operation. Consequently, compliance with the output-based emission limit is not expected to require any additional instrumentation. Therefore, no additional instrumentation is required for conventional utility applications (particularly for new sources) to comply with the output-based emission limit. However, additional signal input wiring and programming is expected to be required to convert the above measurements into the compliance format (lb/MWh gross).

To use an output-based standard for cogeneration units (*i.e.*, units which use steam to both generate electricity and as a process input), the energy content of the process steam must also be considered in determining compliance with the output-based standard. The EPA has determined that existing plant monitoring and energy calculation curves are available and can be easily programmed to determine the steam's equivalent electrical energy component. This component can then be added to the plant's actual gross electrical output to arrive at the plant's total gross energy output.

Since all the reported data obtained throughout the development of the revised standards are in the current format of lb/TBtu heat input, EPA applied an efficiency factor to the current format to develop the output-based limits. The efficiency factor approach was selected because the alternative of converting all the reported data in the database to an output-basis would require extensive data gathering and analyses. Applying a baseline efficiency would essentially convert the selected heat input-based level to an output-based emission limit.

The output-based standard must be referenced to a baseline efficiency. Most existing electric utility steam generating plants fall in the range of 24 to 35 percent efficiency. However, newer units operate around 35 percent efficiency; therefore, 35 percent was selected as the baseline efficiency for new units; 32 percent was selected as the baseline efficiency for existing units. The EPA requests comment on: (1) Whether 35 percent is an appropriate baseline efficiency, (2) how often the baseline efficiency should be reviewed and revised in order to account for future improvements in electric generation technology, and (3) the specific methodology or methodologies appropriate and verifiable for determining the gross energy output.

The efficiency of Utility Units usually is expressed in terms of heat rate, which is the ratio of heat input, based on HHV of the fuel, to the energy (*i.e.*, electrical) output. The heat rate of a utility steam generating unit operating at 32 percent efficiency is 11 joules per watt hour (J/Wh) (10,667 Btu per kilowatt hour (kWh)); at 35 percent efficiency, the values are 10 J/Wh (9,833 Btu/kWh).

Determination of the gross efficiency of a cogeneration unit includes the gross electrical output and the useful work achieved by the energy (*i.e.*, steam) delivered to an industrial process. Under a Federal Energy Regulatory Commission (FERC) regulation, the efficiency of cogeneration units is determined from "* * * the useful power output plus one-half the useful thermal output * * *," 18 CFR part 292, section 205. Therefore, to determine the process steam energy contribution to net plant output, a 50 percent credit of the process steam heat was selected. This approach is consistent with the approach taken in the most recent subpart Da revision to the NO_X standard.

The proposed section 112 MACT rule does not include a specific methodology or methodologies for determining the unit gross output. The EPA would specify such methods in the final rule.

The proposed format for Hg also includes the use of a 12-month rolling average in determining compliance. The EPA considers use of an averaging period to be appropriate because Hg is not an acute health hazard in the context of its emission from Utility Units. Rather, it is a persistent bioaccumulative HAP that lends itself to monitoring over a longer-term period. Several periods could be used for this purpose, including 12-month rolling, quarterly, and yearly. Electric Utility Units already monitor their fuel use on a monthly basis for reporting to the DOE. Therefore, EPA is proposing to base the Hg standard on a 12-month rolling average period.

The EPA requests comment on all aspects of the analyses and conclusions set forth above, including (1) whether 32 and 35 percent are appropriate baseline efficiencies; (2) how often the baseline efficiency should be reviewed and revised in order to account for future improvements in electric generation technology; (3) whether the output-based standard option in the proposed rule will promote energy efficiency improvements; (4) the specific methodology or methodologies appropriate and verifiable for determining the gross output of a steam generating unit; and (5) whether a fixed percentage credit of 50 percent is representative of the useful heat in varying quality of process steam flows.

3. How Did EPA Determine the Proposed MACT Floor for Existing Units?

All standards established pursuant to the process set forth in section 112(d) of the CAA must reflect the maximum degree of reduction in emissions of HAP that is determined to be achievable by the industry source category. For existing sources, MACT cannot be less stringent than the average emission limitation achieved by the best-performing 12 percent of existing sources for categories and subcategories with 30 or more sources (excluding certain sources as specified by the CAA). This level of control is known as the MACT floor. Because the MACT floor represents the level of reduction in HAP emissions that is actually achieved by the best-performing sources in the source category, EPA may not consider cost and other impacts in determining the MACT floor.

This section describes the process used by EPA to determine the MACT floors for each of the subcategories included in the coal- and oil-fired electric utility source category. The MACT floor determination process for this source category was complicated by the many ranks/grades of fossil fuels used in the industry and the capability of the air pollution control technologies currently used in the industry to reduce Hg and Ni emissions.

The initial step in developing a MACT floor or floors for a source category is determining whether subcategorization is appropriate. A discussion of EPA's analysis and conclusions concerning subcategorization of coal-fired units is set forth above.

One potential approach for establishing MACT floors for the subcategories is to require all of the sources in a category to implement precombustion pollution prevention measures. The precombustion techniques include fuel substitution, process changes, and work practices. As discussed in detail below, EPA has determined that none of these approaches are viable for all of the units in the coal- and oil-fired electric utility source category.

Did EPA consider the use of precombustion measures in establishing the MACT floor? The EPA first considered the feasibility of fuel substitution from several perspectives: (1) Switching to other fuels used in the same subcategory (*e.g.*, a "lower" Hg content bituminous coal); (2) switching to fuels used in another subcategory (*e.g.*, firing bituminous coal instead of lignite coal); or (3) switching to natural gas. The EPA considered several aspects of fuel switching in evaluating these alternatives. These aspects included whether switching fuels would achieve lower Hg and Ni emissions, whether fuel switching could be technically achieved considering the existing design characteristics of electric Utility Units, and the availability of various types of fuel.

For coal-fired units, the first aspect considered was fuel switching either to a better (or lower Hg-containing) seam of coal used within a subcategory or used in another subcategory. The question of whether switching between coals is a viable option arises from the variation in Hg content and other key attributes in different seams of coal. The data indicate that, although one seam may have less Hg than another, it may be higher in other chemical constituents of concern. The EPA has no data on which to determine the "best" seam, or rank, of coal on which to base such a requirement. Further, even if a "better/best" seam could be identified, changing to a specific or different seam of coal would essentially determine the area or even mine from which the coal could be produced. The fuel substitution issue then becomes dependent on the regional differences in coal characteristics and the subsequent feasibility of placing a burden on units that are located further from the better/best seams. The EPA feels that the intent of the CAA is to develop standards that, to the greatest extent reasonably possible, are consistent across the industry and avoid actions that create regional disparities. The EPA further feels that requiring all plants to combust coal from a specific seam is not a viable long-term solution because the supply of coal from that seam would be rapidly depleted. Finally, EPA has determined (as stated earlier) that the existing Utility Units were designed based on the availability of certain coal ranks and has found that, in some instances, the units were actually co-located with a particular coal source.

Another perceived use of alternate ranks or seams of coal is to use clean coal. The term "clean coal" generally refers to a fuel that is lower in sulfur and/or ash content. Data gathered by EPA indicate that within specific coal ranks, the Hg content can vary significantly and that lower sulfur content does not necessarily mean lower Hg content.

Certain physical characteristics of coal-fired units also limit the effectiveness of prevention measures. A unit may require extensive changes to the coal handling and feeding system (*e.g.*, a stoker using bituminous coal as fuel would need to be redesigned) in order to burn a different rank of coal. Additionally, existing burners and combustion chamber designs are generally not capable of handling different coal ranks, and generally cannot accommodate increases or decreases in the coal volume and shape. For example, burners are designed partially on the hardness of the coal; changing coal ranks could result in a harder coal and increased wear on the burners. The size of the burner and combustion chamber are based, in part, on the heating value of the coal rank; lower rank coals require larger systems for the same amount of heat input. Design changes to allow different coal use may, in some cases, reduce the capacity and efficiency of the unit. Reduced efficiency results in a lack of effective energy usage and may result in less complete combustion and, thus, an increase in emissions.

Another factor supporting EPA's conclusion that precombustion measures are not a viable emissions reductions approach for all units in the category is the lack of available alternative types of fuel for a given unit. Natural gas pipelines are not available in all regions of the U.S. Even where pipelines provide access to natural gas, supplies of natural gas may not be available in adequate quantities for utilities. For example, it is common practice in large metropolitan areas during winter months (or periods of peak demand) to prioritize natural gas usage for residential areas before industrial areas (*i.e.*, natural gas curtailments). Requiring an EPA-regulated utility unit to switch to natural gas would place an even greater strain on natural gas resources, and, in some circumstances, the change would interfere with a unit's ability to run at full capacity. For these reasons, EPA decided that fuel switching is not an appropriate criterion for identifying the MACT floor level of control for existing coal-fired units.

With regard to process changes, EPA found that Hg and Ni emissions of concern from coal- and oil-fired units are primarily dependent upon the composition of the fuel and, to a lesser extent, the combustion process. Consequently, process changes (*i.e.*, changes to unit design/operation) would be ineffective in reducing these fuel-related Hg and Ni emissions. The EPA did not identify any process changes or work practices that would be appropriate criteria for identifying the MACT floor level of control for existing coal- or oil-fired units.

In general, electric Utility Units are designed for efficient combustion. Facilities have an economic incentive to ensure that fuel is not wasted and that the combustion device operates properly and is appropriately maintained. In fact, historical data show that the average heat rate (*i.e.*, heat energy required to produce 1 kWh of electricity) declined by 11-fold between 1899 and the mid-1960s, mainly because of the desire to run efficient plants. The EPA was also unable to identify any uniform requirements or set of work practices that would meaningfully reflect the use of GCP or that could be meaningfully implemented across any subcategory of units. Therefore, EPA has not found combustion practice requirements useful in determining the MACT floor for existing coal- or oil-fired units. However, EPA's inability to establish a combustion practice requirement as part of the MACT floor for existing units does not reduce the incentive for owners/operators to operate their units at top efficiency.

The EPA requests comments and emissions information regarding whether there are any uniform GCP for controlling Hg and Ni that would be appropriate for minimizing Hg and Ni emissions from any subcategory of electric Utility Units.

4. How Did EPA Derive the MACT Floor for Each Subcategory?

As noted above, the EPA has determined that coal rank and resulting system design characteristics warrant subcategorization within coal-fired units. Once EPA determined that precombustion techniques were not helpful in determining the MACT floor for the entire source category, the next step was to develop a MACT floor for each subcategory based on the control technology used by the top-performing units (*i.e.*, equipment based), and the level of emissions reductions (*i.e.*, emission limitation based) that the top units in each subcategory demonstrated.

The EPA had data from an evaluation of the Hg control performance of various emission control technologies that are either currently in use on coal-fired units (designed for pollutants other than Hg) or that could be applied to such units for Hg control. According to the available data, none of the existing control systems were specifically designed to remove Hg; however, most of the controls removed Hg to some degree. The most prevalent control technology used in the industry was the ESP, which was designed to control PM. Fabric filters or the combination of spray dryer adsorbers (SDA) and fabric filters were, however, found to be the most effective control technology for Hg removal generally.

Unfortunately, the best Hg control technology scenarios were not consistent with regard to the extent to which they removed Hg. For these reasons, EPA decided to address Hg under the proposed rule using an emission limitation-based approach as opposed to a control equipment-based approach.

As a result of the preceding evaluations, EPA concluded that the most appropriate approach for determining MACT floors for existing coal- and oil-fired units was to rank the emission test results from units within each subcategory from lowest to highest and calculate a MACT floor emission limitation by taking the numerical average of the test results from the best-performing 12 percent (or equivalent) of affected sources. The MACT floor database consisted of all pollutants described in the 132 test reports, including multiple runs if they were available. Units were ranked based on the subcategorization scheme described elsewhere in this preamble, and then ranked from lowest to highest by Hg emission rates within each subcategory. For oil-fired units, the ranking process was based on the Ni emission rates.

5. How Did EPA Account for Variability?

In establishing the MACT floor(s) for existing sources in a particular category or subcategory of sources, section 112(d)(3) of the CAA calls for EPA to determine the average level of emission limitation actually being achieved by the best-performing existing sources in that category or subcategory. For combustion sources such as Utility Units, variability in both the Hg or Ni content of the fuel combusted and the performance of a particular control device have a significant impact on the determination of the level of emission limitation actually being achieved. As a result, it is essential that EPA be able to identify and quantify the level of variability arising from these sources. This is borne out by the test report data EPA obtained through the ICR. That data, which EPA is confident are representative of the industry, shows a significant degree of variability, even within a given subcategory. The EPA, therefore, decided it was necessary to develop a methodology to address the multiple sources of the observed variability in order to assure that an emission limitation value could be derived that was representative of what was actually being achieved by the best-performing units under all conditions expected to be encountered by those units. The origins of variability and approaches available for addressing the variability found in the test data are described below.

Variability is inherent whenever measurements are made or whenever mechanical processes operate. Variability in emission test data may arise from one or more of the following areas: (1) The emission test method(s); (2) the analytical method(s); (3) the design of the unit and control device(s); (4) the operation of the unit and control device(s); (5) the amount of the constituent being tested in the fuel; and, (6) composition of the constituents in the fuel and/or stack gases.

Test and analytical method variability can be quantified by statistical analysis of the results of a series of tests. The results can be analyzed to establish confidence intervals within which the true value of a test result is presumed to lie. Confidence intervals can be estimated for multiple-run series of tests based on the differences found from one test run to the next, with only the upper confidence interval having meaning (signifying the chance of the standard being exceeded).

When testing is done at more than one unit, similar confidence intervals can be established to account for the variability from unit-to-unit. One can combine the test-to-test and unit-to-unit variability into a single factor that can be applied to reported test values to give an upper limit for the likely true value. One can also estimate the combined factor for any desired confidence level.

Another source of variability is the time interval during which the test is being conducted. Testing for a short time may not reveal the range of emissions that would be found over extended time periods. Normal changes in operating conditions or in fuel characteristics may affect emission levels over time. For example, an increase in the Hg or Ni content of the fuel being fired in a unit may tend to increase the Hg or Ni emission rate from the associated stack, even where the control efficiency of the APCD remains constant. Mercury emission rates may also change with unit loads due to changes in the gas flow rate through APCD downstream from the unit which may affect APCD effectiveness.

Variability in control efficiency or emission rates may be addressed in a number of ways, depending on the circumstances existing within the source category. For example, different test run results can be analyzed statistically to arrive at an upper limit that represents the highest likely value for each test planned for use in setting emission limits. The poorest-performing (worst-case) unit in the top 12 percent of each subcategory can be reviewed to determine the causes of poor performance. A factor, which when applied to each of the test runs, can more accurately reflect performance over the full range of operating conditions can then be developed. This results in emission values that would not likely be exceeded over long time periods. Another approach is to look only at the performance of control devices used by sources in the top 12 percent and then use that information to determine likely emissions reductions for different devices operating on different units firing different fuels. The range in emissions reductions derived in this manner could then be used to set upper limits of expected control performance (*i.e.*, to identify the best performance that can be expected under the worst conditions); then, these limits could be used, as above, to set emission limitations for each subcategory. A third approach is to identify correlations between constituents of concern and other, perhaps more easily measured, constituents that can be used to develop algorithms that incorporate variability.

In the context of developing a MACT standard, the issue of how to appropriately address variability arises in deriving the MACT floor level of control. In order to determine the average emission limitation actually being achieved by the best-performing sources in a category or subcategory, EPA must determine how those sources will perform over the full range of operating conditions they can reasonably be anticipated to encounter. Addressing variability in the MACT floor calculation requires that all of the origins of variability be assessed and quantified into factors that can be incorporated into the emission limitation calculations for each subcategory's floor. In this way, the actual performance of each of the floor units over the full range of operating conditions can be derived. The result of this approach is that the measured emission rate for each unit used for floor calculations is increased to account for the variability found from statistical analysis, worst-case analysis, or control device performance analysis. The performance of each unit in the top 12 percent of its subcategory would be adjusted to reflect the uncertainty associated with the various origins of variability, and the average emission rate for these units would be used as the floor emission limitation.

In trying to address the apparent sources of variability in the emissions test data, EPA tried to obtain data that reflected as many different plant configurations as would be found in the entire industry profile and, through the ICR, required tests to be conducted at units believed to be representative of the various plant configurations and operating conditions found within the source category. The tests and measurements, typically a three-run series of manual samples taken over 1 or 2 days of testing, are limited by the emission test method's accuracy and precision, by the short duration of the test, and by differences from one run to the next and one unit to the next. Together, these factors bring into question the accuracy of the results of the tests as a measure of a particular units performance over time. The EPA has evaluated the total population of test results to determine a valid test method variability factor for each type of control device as well a worst-case fuel variability factor. The EPA determined that it was necessary to evaluate the total population of test results to ensure that the resulting variability factors were an accurate predictor of the impacts of variability on the performance of the floor facilities. The variability factors were then applied in MACT floor emission limitation calculations, as appropriate. Applying these variability factors to the identified performance of the floor facilities, EPA has developed proposed emission limits for Hg for coal-fired Utility Units and for Ni for oil-fired Utility Units. Information contained in the docket provides a detailed description of the analysis of the variability issues, including the methods available and used to address the variability in test data used for the proposed rule.

How did EPA derive the proposed MACT floor emission limitations for existing sources? In order to determine the MACT floor emission limits for existing units, EPA examined the population database of existing sources. Available emissions test data were divided according to the subcategorization scheme described elsewhere in this preamble; first coal- and oil-fired, then the five subcategories of coal-fired units. The EPA examined the existing emission test data to determine the individual numerical average of the test results from the best-performing 12 percent (or equivalent) of each subcategory for Hg or Ni. The EPA then applied the potential uncertainty and variability factors to derive the MACT floor limits. All test data were provided to EPA in an input-based format (lb/TBtu). Therefore, EPA conducted all MACT floor calculations using the input-based format and then converted the input-based format into an output-based format (lb/MWh) as a compliance option, according to the approach described elsewhere in this preamble. The discussion below describes the development of the emission limitation for each subcategory in the electric utility source category.

The EPA initiated the evaluation of the units within each subcategory by ranking them from lowest to highest based on emission rates representing the outlet Hg or Ni concentration of the stack tests. This initial evaluation of the test report data indicated that no specific control technology or combination of technologies could be credited with the better performance; however, the evaluation indicated that fabric filter technology did provide a degree of Hg removal and that ESP units also provided a degree of removal, although to a less consistent and lower degree than did fabric filter units. The EPA further investigated the apparent inconsistency of Hg removal and found that the level of removal of Hg was dependent on the speciated form of Hg as presented to the control device. This phenomenon was further evaluated using the entire database of coal-fired units to determine if the variations in the control device performances could be correlated to the speciated form of the Hg presented to the APCD. This evaluation encompassed an evaluation of existing coal-fired units from the ICR data that provided Hg speciation data, Hg-in-coal data, and pre- and post-last-control unit emissions test data. The data indicated that where Hg was presented to the control device in particulate-bound form, both fabric filter and ESP devices provided a degree of control, with fabric filters generally performing better than ESP units. Where Hg was presented to the control device in an elemental form, the performance of the various control devices was highly variable. Part of the variation is believed to be attributable to the form of Hg in the flue gas, such as chlorine compounds. However, part of the variation is not understood at this time, thus the data are inconclusive. Testing has shown that the proportion and type of speciated Hg presented to an APCD is not consistent; however, as stated above, the data do indicate that PM controls are reasonably effective where particulate-bound Hg is present. This variation of the proportions of speciated Hg within the flue gas between units provided further explanation for the observed removal characteristics for different units using the same control technology. Further evaluation of Hg speciation indicated that different coal ranks tend to speciate to a predominantly similar proportion of speciated forms of Hg, thus further supporting the rationale for the subcategorization of coal-fired units based on coal rank.

The EPA found, for the reasons indicated above, that although variable, fabric filter and ESP control technologies were reasonable and viable technologies on which to base the MACT floor level of control. The EPA then evaluated performance of the various fabric filter- and ESP-equipped units to determine what criteria would most effectively reflect the performance. The EPA considered using the percent efficiency of the control device, the percent reduction, and outlet concentration as viable criteria to demonstrate performance of the technology. However, the evaluation of these performance criteria proved problematic. The ICR Hg data were based on stack test data for the last control device at each utility unit tested. The emissions were measured in milligrams of Hg per volume of test solution used in the Ontario-Hydro method. Using the duct or stack flue-gas flow volume and the heat input to the unit being tested, the measured quantity of Hg was converted and reported in units of lb/TBtu. In reviewing the data, EPA found that the inlet measurement showed deficiencies due to the flow rate and short duct runs available for testing before the control device, and that these values were suspect as being reliable representations of actual inlet concentrations. The EPA, therefore, determined that evaluation of control device efficiency values based on unreliable inlet concentration data would not be justified. The EPA determined, however, that the outlet concentration data were reliable based on the method used and the fact that only one measurement was needed for the determination of the value. Another option was then to determine Hg reduction efficiency across the system.

This option would also address EPA's desire to promote, and give credit for, coal preparation practices that remove Hg before firing (*i.e.*, coal washing or beneficiation). However, this option requires tracking the Hg concentrations in coal from receipt to stack, and not just before and after the control device(s) and could be difficult to implement. The EPA believes that an emission rate format would allow for the use of precombustion Hg removal processes. As a result, EPA believes that the most credible data element available that quantified performance would be the emission rates as provided in the stack test reports.

The emission limitation for Hg emissions from existing coal-fired units was determined by analyzing the available Hg emissions data in each subcategory. The data were obtained from the ICR noted earlier and included data for Hg emissions, and Hg-in-coal and Cl-in-coal data for 1999. The MACT floor calculations were based on the average performance of the top 12 percent of units in the individual subcategories of bituminous coal, subbituminous coal, lignite coal, coal refuse, and IGCC (coal gas).

The variability of Hg emissions from coal-fired units is significantly influenced by the variability over time in the composition of the coal burned as fuel (*i.e.*, differences in Hg content, Cl content, and heat content of coal). The differing physical and chemical properties of Hg-containing compounds in the flue gas result in significant differences in the feasibility and effectiveness of controls for removing the compounds from flue gas. The effectiveness of control devices at removing Hg depends to a large extent on the species of Hg in the flue gas. As a general matter, all of the control devices currently installed on Utility Units are most effective at removing Hg in the oxidized form (*e.g.*, Hg^{++}). Thus, which Hg species are present in the flue gas impacts the amount of Hg that will be captured by control devices and how much Hg will be released in stack emissions. Importantly, studies have shown that the Cl content of the coal has a significant impact on which Hg compounds are contained in the flue gas. Generally, the higher the Cl content relative to the Hg content, the greater the percentage of oxidized Hg (ionic or Hg^{++}) contained in the flue gas. When combined with other relevant data, such as coal Hg content, the Cl content of coal can thus be used to predict a particular control device's ability to effectively reduce Hg emissions.

The data results from a multi-variable study EPA performed on the ICR data demonstrate the significance of coal Cl content to Hg emissions controllability. The higher the Cl:Hg ratio, the more likely the formation of mercuric chloride (Hg^{++}) that is more readily captured by existing control devices. This Cl:Hg ratio is independent of the coal rank as an indicator of Hg controllability.

In summary, the coal Cl content is one of the primary determinants of which Hg-containing compounds will be present, and in what amounts, in the flue gas of an individual utility unit. The differing physical and chemical properties of Hg-containing compounds in the flue gas result in significant differences in the feasibility and effectiveness of controls for removing the compounds from flue gas.

The EPA determined that the stack tests in the ICR database alone are insufficient to estimate the effect of fuel variability over time on the emissions of the best-performing facilities. The ICR database contains extensive data on variation in coal composition recorded over the course of a year. Therefore, to link fuel composition data to Hg emissions data, EPA developed a methodology using correlation equations to represent the relationship between the fraction of Hg removed and Cl concentration for each of the control configurations used by the best-performing units. The correlation equations provide a mechanism for predicting the performance of each of the control devices installed on floor units when the unit is combusting any of the coals received by that unit during 1999. The steps used to develop these correlation equations are set forth below.

The units in each of the five subcategories were sorted in ascending order of stack-tested Hg emission factor, measured in units of lb/TBtu (as adjusted by a method that normalizes Hg emissions to coal heat content (F-factor Adjustment)). Accordingly, the top performing units of each subcategory were selected for further analysis.

The control configuration of each of the best-performing units (*i.e.*, the floor units) was identified. The Hg removal fraction and test coal Cl concentrations were obtained from the ICR database for each of the units in the database that have one of the identified control configurations. It was necessary to look at all units employing the identified control configurations to ensure that the statistical r^2 values of the subsequently derived correlation equations were sufficiently high to conclude that the correlation equations could accurately predict the Hg removal efficiency of a particular control device in operation on one of the floor units.[6] Finally, a correlation equation was derived for each identified control configuration by fitting a mathematical expression to the Hg removal fractions and corresponding Cl concentrations obtained from the ICR stack test database. The correlation equations thus derived can be applied to any control device for which the Hg control efficiency, when the unit being controlled is burning a coal with an identified Cl:Hg ratio, is known to predict the control efficiency of that device when a coal with a different Cl:Hg ratio is burned.

In selecting the format of the correlation equation, care was taken that the mathematical expression accurately reflected the physical and chemical process by which Cl contributes to the controllability of stack Hg emissions. The correlation equation is based on the assumption that the rate of conversion of Hg to mercuric chloride (an oxidized form) is proportional to the Cl concentration in the coal, irrespective of coal rank. With this expression, the maximum removal fraction is limited to 1, because the exponent term is always nonnegative, regardless of the Cl concentration. This corresponds to the real-world limitation that no more than 100 percent of the Hg in flue gas can be removed (*i.e.*, there cannot be negative Hg emissions). As the coal Cl concentration drops to zero, the Hg removal fraction does not approach zero because some Hg removal is achieved even without reaction with Cl. The purpose of deriving a correlation equation for each control configuration used by the top performing units was to provide a numerical means of predicting the fraction of Hg removed for the best-performing sources over the entire range of fuel variability experienced by each of those sources over the course of a year. Correlation equations were derived for each control configuration, but were only used to predict Hg removal if they

[6] The r^2 measures the strength of the relationship between any two variables in the sense that it provides the proportionate reduction in the sum of squares of vertical deviations obtained using a least squares approach. The largest value r^2 can attain is 1, which occurs when the residual sum of squares is equal to zero (*i.e.*, all the data points lie on the curve), while the smallest value that r^2 may take is 0, which means there is no improvement in predictive power using the independent variable. In our example, the two variables of concern in effecting Hg reductions are the Hg and Cl content of coal. Thus, the closer r^2 comes to 1, the stronger the relationship between these two variables, and reductions in Hg emissions, for any given coal sample; and, on the other hand, the closer r^2 comes to 0, the more likely there is little or no relationship between the two variables, and reductions in Hg emissions, for a given coal sample.

were found to have acceptable explanatory power.

To determine whether the explanatory power of each correlation equation warranted its use on a larger range of ICR coal composition data, each correlation equation was validated against the ICR stack test data. For each of the Cl concentrations in the ICR stack test database for 1999, the Hg removal fraction was calculated by using the correlation equation with parameters selected to give the best fit to the data. A correlation coefficient was then calculated to evaluate the accuracy of the fit.

For each of the best-performing units, unit-specific coal composition data for a one-year period were extracted from the ICR database to find the coal heat content, Hg content and Cl content. For each set of coal composition data from the ICR database, the controlled Hg emissions were calculated by multiplying uncontrolled Hg emissions by (1-Hg removal fraction). For each of the best-performing sources, this process was repeated for each set of measured coal composition values, yielding a range of controlled Hg emission levels for that unit over time.

The test coal composition data from the ICR database (heat and Hg content) was used to calculate the uncontrolled Hg emission level. The Hg removal fraction was calculated in one of the following two ways:

(1) Where the correlation equation was found to have sufficient explanatory power, it was used to estimate the Hg removal fraction based on coal Cl composition data from the ICR data base. This approach accounted for variations in the Hg, Cl, and heat content of fuel.

(2) Where the correlation equation was a poor fit, the Hg removal fraction was based on the average Hg removal fraction observed in the ICR stack tests of that unit. This latter approach yielded a constant removal fraction based upon the source test, and had the effect of reducing the variability of predicted Hg emissions. Under this approach, the measured impact of fuel variability was limited to the effect of variations in Hg and heat content, while variations in Cl concentration were not explicitly considered.

For each of the best-performing units, the calculated controlled Hg emissions, calculated in accordance with the procedures outlined above, were then sorted from smallest to largest to obtain a cumulative frequency distribution (CFD). The 97.5th percentile value of this distribution (*i.e.*, an emission rate that is expected to be exceeded only 2.5 percent of the time) was determined to represent the operation of the unit under conditions reasonably expected to occur at the unit.

It is necessary also to account for inter-unit variability among the top performers. The analysis of within-unit variability considered only the top units in each subcategory. A focus on within-unit variability alone is not expected to capture the full range of emissions variability among the best-performing sources. The EPA accounted for this variability by calculating a 97.5 percent upper confidence level for the mean by use of the student t-statistic.

The EPA calculated the emission limitation for Hg for the subcategories of bituminous-fired, subbituminous-fired, lignite-fired, IGCC, and coal refuse-fired units as follows.

For bituminous-fired units, EPA had data from 32 units. Because this subcategory (*i.e.*, nationwide population) included more than 30 units, EPA determined that the top 12 percent of the units in the subcategory would be composed of 12 percent of the number of units for which EPA had data (*i.e*, 4 units). The EPA determined the top four units from a ranking of units based on their emission rates from the stack test reports. The emission rates from these units ranged from 0.1062 lb/TBtu to 0.1316 lb/TBtu, with an average of 0.118 lb/TBtu. After applying variability as described above and rounding to 2 significant figures, EPA determined the inlet-based emission limitation to be 2.0 lb/TBtu. Using the conversion described elsewhere in this preamble (and based on 32 percent net efficiency), the inlet-based emission limitation of 2.0 lb/TBtu was converted to 21×10^{-6} lb/MWh as the outlet-based emission limitation.

For subbituminous-fired units, EPA had data from 32 units. Because this subcategory (*i.e.*, nationwide population) included more than 30 units, EPA determined that the top 12 percent of the units in the subcategory would be composed of 12 percent of the units for which EPA had test data (*i.e.*, 4 units). The EPA determined the top units from the ranking of the units based on their emission rates from the stack test reports. The emission rates from these units ranged from 0.4606 lb/TBtu to 1.207 lb/TBtu, with an average of 0.738 lb/TBtu. After applying variability as described above and rounding to 2 significant figures, EPA determined the inlet-based emission limitation to be 5.8 lb/TBtu. Using the conversion described elsewhere in this preamble (and based on 32 percent net efficiency), the inlet-based emission limitation of 5.8 lb/TBtu was converted to 61×10^{-6} lb/MWh as the outlet-based emission limitation.

For lignite-fired units, EPA had data from 12 units. Because this subcategory (*i.e.*, nationwide population) consisted of fewer than 30 units, EPA determined that the top performers must include the top 5 units. The emission rates from these units ranged from 3.977 lb/TBtu to 6.902 lb/TBtu, with an average of 5.032 lb/TBtu. After applying variability as described above and rounding to 2 significant figures, EPA determined the inlet-based emission limitation to be 9.2 lb/TBtu. Using the conversion described elsewhere in this preamble (and based on 32 percent net efficiency), the inlet-based emission limitation of 9.2 lb/TBtu was converted to 98×10^{-6} lb/MWh as the outlet-based emission limitation.

For IGCC units, EPA had data on two units. Because this subcategory (*i.e.*, nationwide population) included less than 30 units, EPA determined that all available units would be included and were ranked based on their emission rates from the stack test reports. The emission rates from these units ranged from 5.334 lb/TBtu to 5.471 lb/TBtu, with an average of 5.403 lb/TBtu. The EPA applied the variability factors and, with rounding to two significant figures, determined the IGCC input-based emission limitation to be 19 lb/TBtu. Using the conversion described elsewhere in this preamble (and based on 32 percent net efficiency), the inlet-based emission limitation of 19 lb/TBtu was converted to 200×10^{-6} lb/MWh as the outlet-based emission limitation.

For coal refuse-fired units, EPA had data from two units. Because this subcategory (*i.e.*, nationwide population) included fewer than 30 units, EPA used all units for the calculation based on their emission rates from the stack test reports. The emission rates from these units ranged from 0.0816 lb/TBtu to 0.0936 lb/TBtu, with an average of 0.0876 lb/TBtu. The EPA applied the variability factors as described above and with rounding to two significant digits, determined the input-based emission limitation to be 0.38 lb/TBtu. Using the conversion described elsewhere in this preamble (and based on 32 percent net efficiency), the inlet-based emission limitation of 0.38 lb/TBtu was converted to 4.1×10^{-6} lb/MWh as the outlet-based emission limitation.

The EPA believes that the Hg emission limitations derived above, using the test data adjusted for appropriate variability, provide a reasonable estimate of the actual performance of the MACT floor units under all conditions expected to be encountered over time.

Some have argued that the experience gained from regulation of Municipal

Waste Combustors and Health, Medical and Infectious Waste Incinerators in the early 1990s indicates that coal-fired power plants should be able to achieve 90 percent Hg emission reductions (*see* "Out of Control and Close to Home: Mercury Pollution from Power Plants." Environmental Defense. 2003). The EPA expects that some Utility Units can achieve such high reduction rates, depending on factors such as the Hg and Cl content of different coals, as outlined above. However, there are important technical differences between Utility Units and municipal waste combustors and health, medical and infectious waste incinerators. Consequently, EPA believes 90 percent emission reductions cannot be achieved across all Utility Units in the proposed section 112 time frame. First, the percentage of emissions that is elemental Hg is much larger in coal-fired boilers than in the waste combustors and incinerators (*e.g.*, 50 percent versus 2–20 percent, as stated in EPA's Mercury Study Report to Congress). Second, Hg emissions from the waste combustors and incinerators can be reduced effectively through waste separation techniques, which remove Hg-containing items from the incoming waste stream (*e.g.*, batteries). Application of similar measures at coal-fired Utility Units, such as effective pre-combustion Hg removal, is not widely feasible at this time, though some innovative techniques are under development. Third, the Hg emissions at the waste combustors and incinerators often occur as infrequent, high-concentration "spikes," which are more easily controlled than highly diluted Hg in the flue gas found at coal-fired Utility Units. The technical differences between Utility Units and municipal waste combustors and health, medical and infectious waste incinerators need to be recognized (*see* "Mercury Emissions from Coal-Fired Power Plants: The Case for Regulatory Action," NESCAUM, 2003).

Are there other approaches to addressing variability? The approach selected by EPA for addressing variability is not the only approach that could be appropriate for evaluating emissions from the best-performing units. The Department of Energy (DOE) has conducted a similar analysis to that described above, but with one significant difference. (DOE, 2003.) In calculating a MACT "floor" rate, DOE considered that variability at a best-performing unit could be based on assuming that the unit could switch to a coal not previously burned at the unit during the one-year period covered by the ICR, but having the same rank as the coal used at the best-performing unit. Because the alternative coals were of the same rank and not precluded from use by regulation or permit, DOE concluded that the combination of emission algorithms, unit-specific stack tests, and ICR coal data from other units constituted relevant emission estimates under worst conditions at the best-performing units.

The essence of the DOE analysis was to average at a plant level the Hg and Cl contents of all coals, by rank, in the ICR data base. Then, DOE adjusted the performance test results at the lowest emitting units in the ICR data base by assuming that they burn a coal similar to the 97.5th percent worst plant annual average coal. For bituminous coal units, the coal Cl resulted in the greatest variability in emissions. For subbituminous coals, the coal Hg content was more critical than Cl content. The DOE found that most lignite-fired power plants were directly associated with a single mine, and decided that assuming a switch to coals from other mines was not reasonably justified. Therefore, for lignite units, DOE would recommend using the approach presented earlier by EPA. In addition, for bituminous coals, DOE found that many of the lowest Cl bituminous coals are produced in the western U.S. and are unlikely to be used in eastern power plants, where the bulk of bituminous coal is burned. Those western coals were excluded from the variability analysis.

Using this approach, DOE found that an appropriate MACT floor rate for bituminous coal was 2.6 lb/TBtu heat input. The rate for subbituminous coals was 5.4 lb/TBtu heat input. The EPA seeks comment on alternative approaches to addressing source emission variability, such as DOE's. In particular, we ask for comment on the relevance of *Cement Kiln Recycling Coalition* to the DOE approach.

How did EPA address blended coals? The EPA recognizes that many Utility Units burn more than one rank of coal, either at the same time (*i.e.*, blending) or at separate times during a year (*i.e.*, seasonally). Further, EPA is aware that several units burn a supplementary fuel (*e.g.*, petroleum coke, tire-derived fuel (TDF), etc.) in addition to a primary coal fuel. The EPA recognizes this practice and acknowledges the effect that coal blending (or use of supplementary fuels) will have on Hg emissions. Because this rule does not apply to the non-regulated supplementary fuels, the rule does not provide an emission limitation for those fuels. The EPA believes that the most appropriate means to address the blending scenarios is through the compliance demonstration.

The EPA has identified several blending scenarios that might occur in the industry; blending two or more ranks of coal, blending one rank of coal with a supplementary (non-regulated fuel), or blending multiple ranks of coal with a supplementary (non-regulated) fuel.

There are two potential methods for addressing the blending scenarios where two or more ranks of coal are fired. One approach to address blended coal would be to classify a unit based on the predominate coal it burns. For example, if 90 percent of the coal burned for the compliance period were bituminous, the unit would be classified as bituminous and would have to meet the Hg emission limitation for bituminous coal. Although this approach is desirable from a simplicity standpoint, EPA believes that this approach is not equitable nor reflective of actual practice in the industry. Therefore, EPA is proposing a second, potentially more equitable, approach involving development of a weighted Hg emission limit based on the proportion of energy output (in Btu) contributed by each coal rank burned during the compliance period and the coal's subcategory Hg emission limitation. The weighted emission limit would, in effect, be a blended emission limitation based on the Hg emission limitations of the subcategories of the coals burned.

The other scenarios discussed above involve blending a regulated fuel (*e.g.*, coal or coal refuse) with a supplementary, non-regulated fuel (*e.g.*, petroleum coke, TDF, etc.). The application of the same methods would be appropriate for units that burn a regulated fuel with supplementary, non-regulated fuels; however, there would be no adjustment to the Hg emission limitation with regard to the supplementary, non-regulated fuel.

The weighted Hg emission limitation would be developed based on the proportions of energy output (Btu) contributed by only the regulated fuels. For example, if the unit burned bituminous, subbituminous, and petroleum coke during the compliance period, and where 40 percent of the Btu output was attributable to the bituminous, 40 percent to the subbituminous, and 20 percent to the petroleum coke, the blended Hg emission limitation would be based on the bituminous and subbituminous emission limitations in a 50/50 ratio. The compliance calculation would include the energy output (Btu) of all fuels burned (including the supplementary fuel), the emissions considered would include all Hg emission measured by the CEMS, and the unit would comply with the blended Hg emission limitation. The compliance demonstration outlined in § 63.9990(a)(6) of the proposed rule provides the calculation of the blended Hg emission limitation applicable under this approach.

How did EPA address Ni from oil-fired units? The proposed emission limit for Ni from existing oil-fired units was determined by analyzing the emissions data available. The data were obtained from the Utility RTC which provided information indicating that Ni was the pollutant of concern due to its high level of emissions from oil-fired units and the potential health effects arising from exposure to it. The EPA examined available test data and found that units equipped with ESP units (for PM control) can effectively reduce Ni. The controls currently in use on electric utility oil-fired units to address PM were installed as a result of requirements to address criteria pollutants under other regulations. The data available to EPA indicate that the Ni is present in flue gas streams in varying concentrations, yet mostly in particulate form. The Utility RTC emissions test data support the conclusion that the same control techniques used to control the fly-ash PM will also indiscriminately control Ni and that the effective removal of PM indicates removal of Ni, for a given control device. Therefore, EPA believes that ESP technology represents the MACT floor for Ni for the proposed rule. The EPA has determined that the proposed emission limitation for the oil-fired units should reflect the performance that would be expected over time for a well designed and operated ESP.

The EPA determined the value of the Ni emission limitation by ranking the stack test emission rates for Ni of the 17 units for which EPA had data. The top 12 percent of the units, or 2 units, were controlled by ESP and the range of emission rates was 29.97 to 357.16 with an average of 125.06 lb/TBtu. After applying variability as described above and rounding to 2 significant figures, EPA determined the inlet-based emission limitation to be 210 lb/TBtu. The output-based Ni emission limitation was determined to be 0.002 lb/MWh after conversion using 32 percent net efficiency. The EPA believes that these emission limits are a reasonable estimate of the actual performance of the MACT floor unit in reducing Ni on an ongoing basis.

The Agency is sensitive to the fact that some sources burn fuels containing very little Ni and that compliance with the Ni emission limitation could be burdensome in cases where the potential Ni emissions would be very low. Therefore, EPA is considering an alternative Ni-in-oil emission limit which would be equivalent to the main standard. An existing source would be able to choose to comply with the alternative Ni-in-oil emission limitation instead of the Ni emission limitation (either input- or output-based) to meet the proposed rule. The alternate Ni-in-oil emission limitation would be based on a correlation between the Ni constituent concentration in the oil burned and the expected Ni emissions in the flue gas. Data available to EPA does not provide a consistent correlation methodology for determination of an appropriate Ni constituent level in oil. The EPA is soliciting comment on the usefulness of such an alternative Ni-in-oil limit and the availability of any correlation methodology and data for determining a Ni concentration level in oil that could be shown to be equivalent to the proposed emission limitation.

The EPA solicits comments on these approaches and on others that might present a better method for addressing variability in development of the emission limitations.

How did EPA address dual-fired units? The EPA is aware that an oil-fired unit may fire oil at certain times of the year and natural gas at other times, as well as blends of residual oil and distillate oil. This blending of fuels is conducted for many reasons, most of which are economically driven with regard to the availability of fuels and the price, and may be seasonal in nature. As stated elsewhere in this preamble, EPA considers a unit to be an oil-fired unit if (1) it is equipped to fire oil and/or natural gas, and (2) it fires oil in amounts greater than or equal to 2 percent of its annual fuel consumption. This 2 percent value is intended to represent that amount of oil that a true natural gas-fired unit might use strictly for start-up purposes on an annual basis.

As stated earlier for coal blending, EPA does not intend to address the fuel blending scenarios with specific emission limitations, but rather address the issue during the compliance demonstration.

In the proposed rule, units that burn distillate oil exclusively would be exempt from the requirements of the rule and natural gas-fired units would be excluded from the definition of an affected source. Therefore, the requirements of the proposed rule would apply to units that fire residual oil in any proportion with another oil, and to units that fire residual oil at 98 percent or greater of its annual fuel consumption, where the supplementary fuel is natural gas. The blending scenarios that might occur for oil-fired units include the co-firing of residual oil with distillate oil, and the firing of residual oil and natural gas at different times. The EPA believes that a cutoff of 2 percent fuel oil-firing would separate those units that are "fundamentally" natural gas-fired but, for start-up or other operational needs, periodically burn fuel oil.

Under the proposed rule, a unit that burns residual oil exclusively would be required to meet the oil-fired Ni emission limitations. For units that burn exclusively distillate oil, the unit would be exempted from meeting the Ni emission limitation requirement. For units that blend residual oil with distillate oil, the unit would be required to meet the Ni emission limitations in the proposed rule, and would include all Btus or MWh generated from the use of the distillate oil in the compliance demonstration calculation. Likewise, a unit that burns residual oil during certain periods and natural gas during certain periods would include the natural gas-fired contributions (Btu or MWh) in the compliance calculation.

Although EPA has not identified any other supplementary fuels burned in the oil-fired industry, we are aware that such a scenario may exist or might occur in the future. For the purposes of the proposed rule, EPA intends that where any supplementary fuel is co-fired with residual oil, the Btus or MWh contributed by the supplementary fuel be accounted for in the compliance calculation, and that the unit would be required to meet the Ni emission limitation for existing oil-fired units.

The EPA solicits comment on whether the 2 percent breakpoint is a reasonable basis for allowing those units that use oil only for startup purposes to be exempted from regulation under the proposed rule.

6. How Did EPA Consider Beyond-the-Floor Options for Existing Units?

The EPA considered available regulatory options (*i.e.*, technologies or work practices) that were more stringent than the MACT floor level of control for each of the different subcategories. Except for IGCC, we have not identified technologies or work practices that provide a viable basis for establishing standards beyond-the-floor. Described below are the candidate technologies and work practices that we considered in our analyses. We ask for comment on these technologies and other control techniques that could provide consistently lower levels of emissions of Hg and Ni than those demonstrated by the MACT floor level of control. Additional information on the beyond-the-floor analyses for existing units is available in the document titled, "Beyond the Floor Analysis for Existing and New Coal- and Oil-Fired Electric Utility Steam Generating Units NESHAP" which can be found in the docket.

Coal-fired units. Conventional PM controls (ESP and fabric filters) generally do not remove the vapor-phase Hg^0 from coal-fired unit emissions. This is because these controls do not capture gaseous pollutants. Two technologies that possibly could be used to further reduce the amount of vapor-phase Hg emitted from utilities are sorbent injection and selective catalytic reduction (SCR).

Sorbent injection. Due to their multiple internal pores and high specific surface area, sorbents have the potential to improve the removal of Hg (mostly through the enhanced capture of elemental Hg; sorbents will also remove Hg^{++}) as well as other gaseous pollutants that are carried with combustion fine particulates in all coal-fired subcategories (except IGCC). The extent of the potential Hg removal is dependent on: (1) Efficient distribution of the sorbent (*e.g.*, activated carbon) in the flue gas; (2) the amount of sorbent needed to achieve a specific level of Hg removal which will vary depending on the fuel being burned; (3) the amount of Cl present in the fuel; and (4) the type of PM control device (*e.g.*, at a given sorbent feed rate, a fabric filter provides more Hg control than an ESP because of the additional adsorption that occurs on the bags of the fabric filter because of the increased gas contact time).

Sorbents can be introduced by two basic methods: by channeling flue gas through a bed of sorbent or by direct sorbent injection. Sorbent bed designs consist of fixed-sorbent filter beds, moving beds, or fluidized sorbent filter beds. With direct sorbent injection, after sorbent is introduced into the flue gas, it adsorbs Hg and other contaminants and is captured downstream in an existing or sorbent-specific PM control device. At this time, the types of sorbent that may be viable for use in sorbent injection include two basic types of activated carbon (AC; regular and impregnated), as well as other carbon (mixed with other sorbents) and non-carbon sorbents.

Activated carbon is a specialized form of carbon produced by pyrolyzing coal or various hard, vegetative materials (*e.g.*, wood) to remove volatile material. The resulting char then undergoes a steam or chemical activation process to produce an AC that contains multiple internal pores and has a very high specific surface area. With this internal pore structure, the AC can adsorb a broad range of contaminants. Some studies have shown good to excellent Hg removal with the injection of AC (particularly on bituminous-fired units); however, other studies have not shown good Hg removal (particularly on subbituminous- and lignite-fired units). The Hg removal performance of AC injection seems to be highly dependent on coal rank and composition (*i.e.*, Hg and Cl content of the coal) and specific utility plant configuration (*e.g.*, sequencing of APCD equipment). Further, little long-term data is available.

Chemically-impregnated AC is AC that has been supplemented with chemicals to improve its Hg removal. The Hg in the flue gas reacts with the chemical that is bound to the AC, and the resulting compound is removed by the PM control device. Typical impregnants for AC are Cl, sulfur, and iodide. Chemically-impregnated AC have shown enhanced Hg removal over regular AC. Chemically-impregnated AC require smaller rates of carbon injection than does regular AC for equivalent Hg removals. The required carbon-to-mercury mass ratio may be reduced by a factor of from 3 to 10 with the chemically-impregnated AC. The cost per mass unit of impregnated AC may, however, be significantly greater than that of unmodified AC.

Other commercially available sorbent materials are Sorbalit™ (a mixture of lime with additives and 3 to 5 percent AC) and Darco FGD (an AC derived from lignite). Zeolites comprise another category of sorbent. There are naturally occurring mineral zeolites, in addition to commercially available synthetic zeolites. Both types contain large surface areas and have a good potential for Hg removal.

Although AC, chemically-impregnated AC, and other sorbents show potential for improving Hg removal by conventional PM and SO_2 controls, this technology is not currently available on a commercial basis and has not been installed, except on a demonstration basis, on any electric utility unit in the U.S. to date. Further, no long-term (*e.g.*, longer than a few days) data are available to indicate the performance of this technology on all representative coal ranks or on a significant number of different power plant configurations. Therefore, we do not believe these technologies provide a viable basis for going beyond-the-floor.

Selective catalytic reduction. Although designed as a NO_X control technology, SCR has been shown in recent emissions testing to have the ability to transform certain species of Hg into other speciated forms that are easier for conventional PM and SO_2 controls to capture. The effect can be seen most prominently when an SCR is installed between the PM control device and a wet FGD control device on a unit that is already controlled by such technologies. The Hg which would (in the absence of the SCR) tend to remain as Hg^0 is oxidized, and this highly soluble Hg^{++} is then removed by the wet FGD. This Hg reduction effect has been observed in limited stack testing on bituminous coal-fired units. Results on subbituminous coal-fired units have not been uniformly successful. To EPA's knowledge, no commercial-scale, lignite-fired, SCR-equipped unit has been tested to date, though it is entirely possible that greater Hg removal would result when applied to a lignite-fired unit. Similarly, SCR has not been tested on all types of coal sources.

The EPA requests comments on whether sorbent injection or SCR should be considered as viable beyond-the-floor options for existing coal-fired units. Our preliminary determination is that sorbent injection has not been sufficiently demonstrated in practice nor have long-term economic considerations been evaluated to allow sorbent injection to be considered viable as a beyond-the-floor option. With regard to the use of SCR, the EPA has inadequate information on which to base a beyond-the-floor standard. The EPA is aware that research continues on ways to improve Hg capture by PM controls and sorbent injection and on the development of novel Hg capture techniques. Therefore, EPA also requests comments on whether other control techniques have been demonstrated to consistently achieve emission levels lower than levels on similar sources achieving the proposed MACT floor level of control. Comments should include information on emissions, control efficiencies, reliability, current demonstrated applications, and costs, including retrofit costs.

IGCC units. The EPA believes the best potential way of reducing Hg emissions from existing IGCC units is to remove Hg from the syngas before combustion. An existing industrial IGCC unit has demonstrated a process, using sulfur-impregnated AC carbon beds, that has proven to yield 90 to 95 percent Hg removal from the coal syngas. (Rutkowski, 2002) This technology could potentially be adapted to the electric utility IGCC units. The EPA believes this to be a potentially viable option for IGCC units.

We considered using sorbent bed technology as beyond-the-floor for existing IGCC units but, because of concerns about the costs involved and because existing IGCC units utilize older technology, have decided not to pursue this option. The EPA is, however, proposing that the use of a sorbent bed to remove Hg from coal gas be considered as the beyond-the-floor option for new IGCC units. The EPA requests comments on whether the use of this or other control techniques have been demonstrated to consistently achieve emission levels that are lower than levels from similar sources achieving the proposed existing MACT floor level of control. Comments should include information on emissions, control efficiencies, reliability, current demonstrated applications, and costs, including retrofit costs.

Coal refuse-fired units. All of the 13 coal refuse-fired units existing in 1999 use FBC; 10 of these 13 units inject limestone as a sorbent for SO_2 control, and 4 units are equipped with SCR for NO_X control. The only two coal refuse-fired units on which performance tests were conducted in response to the ICR are the MACT floor facilities for the coal refuse-fired subcategory.

The EPA knows of no technologies that could be used as beyond-the-floor options for coal refuse units. However, the EPA requests comments on whether existing coal refuse-fired units could use any control techniques that have been demonstrated to consistently achieve emission levels that are lower than levels for similar sources achieving the proposed existing MACT floor level of control. Comments should include information on emissions, control efficiencies, reliability, current demonstrated applications, and costs, including retrofit costs.

Oil-fired units. The only emission control technology that EPA is aware of to consider as a beyond-the-floor option for existing oil-fired units is fabric filtration. Fabric filters have been shown in pilot-scale testing to be more effective at reducing Ni emissions than an ESP. However, the use of fabric filters on oil-fired units is also known to be problematic due to the prevalence of the "sticky" PM emitted from such units which sticks to the fabric and creates a fire safety hazard. No existing oil-fired units are known to employ fabric filters as their PM control. Because of this, EPA does not consider fabric filters to be a viable beyond-the-floor option for oil-fired units.

The EPA requests comments on whether fabric filters should be considered as a beyond-the-floor option for existing oil-fired units. The EPA also requests comments on whether other control techniques have been demonstrated to consistently achieve Ni emission levels that are lower than levels for similar sources achieving the proposed MACT floor level of control. Comments should include information on emissions, control efficiencies, reliability, current demonstrated applications, and costs, including retrofit costs.

7. Should EPA Consider Different Subcategories for Coal- and Oil-Fired Utility Units?

Although EPA has proposed subcategorizing coal-fired units into five subcategories (bituminous coal, subbituminous coal, lignite coal, coal refuse, and IGCC), another possible option is to subcategorize coal-fired units into four subcategories (bituminous and subbituminous coals, lignite coal, coal refuse, and IGCC). This second option is claimed by some industry sources to allow greater fuel choice flexibility. Approximately 23 percent of the coal-fired units in 1999 fired a blend of coal ranks or coals and other fuels. The majority of blended coal-fired units in the U.S. combust a blended coal composed of bituminous and subbituminous coal, either through direct blending or through independently combusting each coal at some period during the year. A standard that would subcategorize bituminous and subbituminous together would allow easier emissions permitting and flexibility because most units do not keep the ratio of the coals blended constant.

Although the above subcategorization scheme is not included in this proposal, the EPA specifically requests comments on whether additional or different subcategories should be considered. Comments should include detailed information regarding why a new or different subcategory is appropriate (based on the available data or adequate data submitted with the comment), how EPA should define any additional/different subcategories, how EPA should account for varied or changing fuel mixtures, and how EPA should use the available data to determine the MACT floor for any new or different categories.

8. How Did EPA Determine the Proposed MACT Floor for New Units?

For new sources, the CAA requires that the MACT floor be based on the emission control achieved in practice by the best-controlled similar source, as determined by EPA. The MACT standard is subsequently based on any combination of measures or techniques that are ascertained to have contributed to that level of control (*e.g.,* pollution prevention alternatives, capture and control technologies, operational limitations, work practices) unless a more stringent level of control is required based on the above-the-floor analysis. Because the MACT floor represents the level of reduction in HAP emissions that is actually demonstrated by the best-controlled similar source, EPA may not consider cost and other impacts in determining the floor.

In order to develop a MACT floor for new coal- and oil-fired units, EPA used the same data described above for existing sources. With regard to Hg and Ni emissions from new units, EPA believes that the character and levels of Hg and Ni emitted by new coal- and oil-fired units will be similar to those emitted by existing coal- and oil-fired units because the source of Hg and Ni is primarily related to the fuel. The EPA has no data or information that indicate that this situation will change in the future, particularly because EPA anticipates the use of primarily the same fossil fuel sources for new units as are being used for existing units.

The EPA is aware that the industry has some ability during the designing of new units to choose coal or oil that would minimize emissions of Hg and Ni and recognizes that the MACT standard for new units should, to the extent possible, encourage the industry in that direction. The type, grades, and ranks of coal and grades of oil available for future use in new units will not likely change, and the availability and economics of the fuel choice for these units will likely still be a dominating factor in the design of new units. Future technology may, however, allow for better efficiencies in the units and, potentially, the use of a wider range of fossil fuels for a given locale or region.

The EPA does believe that Hg from coal-fired units and Ni from oil-fired units will remain a concern and that regulation of emissions of Hg and Ni is warranted for new coal- and oil-fired units under the proposed rule.

As was the case for existing units, in developing a MACT strategy for new units, EPA considered several prevention measures as an alternative to the application of Hg and Ni control technology. These measures were the same precombustion techniques evaluated for existing units, which included fuel substitution, process changes, and work practices.

The EPA first considered the feasibility of fuel substitution from several perspectives: (1) Switching to other fuels used in the same subcategory (*e.g.*, a "lower" Hg content bituminous coal); (2) switching to fuels used in another subcategory (*e.g.*, firing bituminous coal instead of lignite coal); or (3) switching to natural gas. The EPA considered several aspects of fuel switching in evaluating these alternatives. The EPA recognizes that an owner/operator, in designing a new unit, would be able to choose a perceived better coal rank (between subcategories) or a perceived better coal seam within a rank (within the subcategory) based on known issues of Hg and other pollutant control and would be able design the new unit to that fuel's characteristics. However, the economics of fuel availability would still be a determining factor as to what fuel was chosen, particularly with regard to new units co-located with existing units.

With regard to a possible EPA requirement for new sources to burn natural gas, EPA believes that availability and economics again would determine whether a source would chose to burn natural gas and that such a requirement would be unduly restrictive given the owner/operator's inability to control access to, or availability of, natural gas. For these reasons, EPA decided that mandated fuel type is not an appropriate criterion for identifying the MACT level of control for new coal-fired units. In any event, we do not believe that we can or should prescribe a given fuel type because of the implications on electricity reliability, energy security, etc.

With regard to process design alternatives and GCP, EPA believes, as discussed elsewhere in this preamble for existing sources, industry has a strong economic incentive to pursue improvement in combustion and plant efficiencies and that the trends in design and technology development will continue in the direction of improvement in efficiencies such that imposition of regulatory incentives based on the existing knowledge base would be not only unnecessary but potentially restrictive. In addition. we do not have the data necessary to establish such a standard.

As with existing units, EPA therefore determined that precombustion techniques were not viable for application in the MACT standard for new coal- or oil-fired units.

Once EPA had determined that pollution prevention alternatives would not be appropriate for the new coal- or oil-fired MACT development, EPA then evaluated the control technology used by the top performing unit (*i.e.*, equipment based), and the level of emissions reductions (*i.e.*, emission limitation based) that the top unit in each subcategory demonstrated.

The EPA used the same data available for existing units which provided an evaluation of the Hg control performance of various emission control technologies that are either currently in use on coal-fired units (designed for pollutants other than Hg) or that could be applied to such units for Hg control. The EPA decided to address Hg for new units using an emission limitation-based approach.

As was discussed in MACT floor development for existing sources, EPA is confident that the data available were obtained from units representative of the industry; however, EPA did believe that some adjustments to the data were justified in light of the variability in test method and in Hg-in-fuel that was discussed previously with regard to existing units. Although it was necessary to address the variability issues, the use of one data set (*i.e.*, the best unit vs. the top units) negated the applicability of the unit-to-unit variability issue. Otherwise, the variability issues were addressed in the same manner as was discussed above for existing units.

The MACT floor for new units is based on the emission control achieved in practice by the best-performing similar source. As noted earlier, EPA believes it reasonable to subcategorize new sources in the same manner as has been done for existing sources. In order to develop an emission limitation for new coal- and oil-fired units, EPA ranked the existing coal- and oil-fired units from lowest emitting to highest within each subcategory based on Hg or Ni emission rates from the stack test data. The EPA then took the numerical performance value from the best-performing unit (or equivalent).

The EPA then applied the potential uncertainty and variability in the emission test reports and worst-case Hg in fuel variability (if applicable) to derive the Hg emission limitation values for new units.

Because test data were provided to EPA based on an input-based format (lb/TBtu), EPA conducted the emission limitation calculations using the input-based format and then converted the input-based format into an output-based format (lb/MWh) according to the approach described elsewhere in this preamble for the proposed rule. The discussion below describes the development of the emission limitation for each subcategory and each regulated pollutant for coal- and oil-fired units.

Mercury from new coal-fired units. The emission limit for Hg emissions from new coal-fired units was determined by analyzing the available Hg emissions data in each subcategory. The data were obtained from the ICR and included data for Hg emissions and Hg- and Cl-in-coal data from all coal-fired units for 1999. The MACT emission limitation calculation was based on the performance of the best similar source in the individual subcategories of bituminous coal, subbituminous coal, lignite coal, coal refuse, and IGCC (coal gas).

This performance value was adjusted for variability by using an approach consisting of a combination of the statistical analysis of the emissions test data and the application of a factor representing the ratio of the Hg-in-coal during the stack testing to the highest Hg-in-coal reported for the unit during 1999 (ICR test). The variability approach used for adjusting the new unit's Hg emissions data was modified to a simplified version of the existing unit's variability factor that reflected the removal of the unit-to-unit variability issue. The worst-case Hg-in-coal issue was addressed in the same manner as the existing units, based on the Hg- and Cl-in-coal data for the individual unit. The EPA chose the same confidence interval (97.5 percent) as was used for existing units, for the reasons discussed in that section.

For bituminous-fired units, the best-controlled unit was controlled with a fabric filter, and the Hg emission factor was 0.132 lb/TBtu. This value was adjusted for variability as described above, converted to the output-based format using the 35 percent efficiency factor, with a resulting output-based Hg emission limitation for new bituminous-fired units of 6.0×10^{-6} lb/MWh.

For subbituminous-fired units, the best-controlled unit was also controlled with a fabric filter, and the Hg emission factor was 0.663 lb/TBtu. This value was adjusted for variability as described above, converted to the output-based format using the 35 percent efficiency factor, with a resulting output-based Hg emission limitation for new subbituminous-fired units of 20×10^{-6} lb/MWh.

For lignite-fired units, the best controlled unit was controlled with an ESP, and the Hg emission factor was 6.902 lb/TBtu. This value was adjusted for variability as described above and converted to the output-based format using the 35 percent efficiency factor, with a resulting output-based Hg emission limitation for new lignite-fired units of 62×10^{-6} lb/MWh.

For IGCC units, the best-controlled unit was uncontrolled, and the Hg emission factor was 5.471 lb/TBtu. This value was adjusted for variability as described above and converted to the output-based format using the 35 percent efficiency factor, with a resulting output-based Hg emission limitation for new IGCC units of 200×10^{-6} lb/MWh. However, EPA believes that a 90 percent reduction in Hg emissions is possible from new IGCC units based on the use of carbon bed technology. Therefore, EPA is proposing an output-based Hg emission limitation for new lignite-fired units of 20×10^{-6} lb/MWh as a possible beyond-the-floor level of control for new IGCC units.

For coal refuse-fired units, the best-controlled unit was controlled with a fabric filter, and the Hg emission factor was 0.094 lb/TBtu. This value was adjusted for variability as described above and converted to the output-based format using the 35 percent efficiency factor, with a resulting output-based Hg emission limitation for new coal refuse-fired units of 1.1×10^{-6} lb/MWh.

The EPA believes that these Hg emission limitations, based on the best-performing unit with associated variability applied, are a reasonable estimate of the actual performance of the MACT floor unit on an ongoing basis.

Blended coals. The EPA recognizes that new Utility Units may still be designed to burn more than one rank of coal, either at the same time (*i.e.*, blending) or at separate times during a period of time (*i.e.*, seasonally). The EPA finds no reason to address blended coals differently for new units than has been proposed for existing units. Therefore, the method of addressing blended coals with regard to the Hg emission limit calculation will remain the same for new units as is proposed for existing units. Further, EPA believes that consistency in the compliance method would be appropriate, because many utility owners/operators will at some point be addressing compliance for both new and existing units at the same facility.

Nickel from new oil-fired units. The proposed emission limit for Ni from existing oil-fired units was determined by analyzing the emissions data available. The data were obtained from the Utility RTC which provided information indicating that Ni was the pollutant of concern due to its high level of emissions from oil-fired units and the potential health effects resulting from exposure to it. The EPA examined available test data and found that ESP-equipped units can effectively reduce Ni. The Ni average concentration from the emission data of the best-controlled oil-fired unit was used to determine the emission limitation for new oil-fired units. The best oil-fired unit Ni emission value from the stack test data was 0.0046 lb/TBtu. This emission factor was then adjusted for uncertainty by applying variability factors as described above for existing units, with a resulting input-based Ni emission limit of 76 lb/TBtu. The EPA then converted the input-based value using the 35 percent net efficiency factor to derive the output-based value for the proposed rule. The resulting proposed Ni emission limitation for new oil-fired units is 0.0007 lb/MWh. The EPA believes that this emission limitation is a reasonable estimate of the actual performance of the MACT floor unit on an ongoing basis.

The EPA is also considering development of an alternative Ni-in-oil limit for new oil-fired units. The EPA solicits comment as to the usefulness of such a limit and any available data or methodology to determine a Ni constituent level in oil that would be equivalent to the proposed Ni emission limitation.

Dual-fired units. The EPA is aware that new oil-fired units may be designed and built to fire a combination of oil grades and/or natural gas, as are existing units. The EPA believes that the reasons for burning natural gas and/or any grade of oil will continue to be based on economics or availability of fuel (*i.e.*, seasonal considerations). Therefore, EPA intends to address new oil-fired units that burn a combination of oil grades and/or natural gas in the same manner as existing units.

The method and rationale for determining the MACT floor for existing and new units is presented in detail in the document titled "MACT Floor Analysis for Coal- and Oil-Fired Electric Utility Steam Generating Units NESHAP" which can be found in the docket.

9. How Did EPA Consider Beyond-the-Floor for New Units?

Once the MACT floor determinations were done for new units in each subcategory (by fuel type), EPA considered various regulatory options more stringent than the MACT floor level of control (*i.e.*, additional technologies or work practices that could result in lower emissions) for the different subcategories.

Due to the technical complexities of controlling metal HAP emissions from the sources affected by this rule, however, EPA has not been able to determine whether identified potential beyond-the-floor options are available and demonstrated. Consequently, EPA is describing the possible beyond-the-floor options of which the Agency is aware for new units and requests comment on these technologies and other control techniques that have been demonstrated to provide consistently lower levels of emissions than those achieved by the proposed new unit MACT floor level of control.

The following are possible beyond-the-floor control options for new units that EPA is considering for the proposed rule.

Coal-fired units. As is explained for existing coal-fired units elsewhere in this preamble, two technologies that possibly could be used to further reduce the amount of vapor-phase Hg emitted from utilities are sorbent injection and SCR. As explained elsewhere in this preamble, however, sorbent injection is not currently available on a commercial basis and has not been demonstrated on a utility unit operating at full capacity over an extended period of time. As also discussed previously, SCR has not shown the same change-in-speciation effect on Hg emissions on all types of coal sources.

The EPA requests comments on whether sorbent injection or SCR should be considered as a beyond-the-floor option for new coal-fired units and whether these units could use any other control techniques that have been demonstrated to consistently achieve emission levels that are lower than those from similar sources achieving the proposed MACT floor level of control. Comments should include information on emissions, control efficiencies, reliability, current demonstrated applications, and costs.

IGCC units. Because of their design, IGCC units have no external APCD controls. Therefore, as is explained for existing IGCC units elsewhere in this preamble, the best potential way of improving Hg removal from IGCC units is to remove the Hg from the syngas before combustion. Based on published information regarding the industrial IGCC unit noted earlier, EPA believes that a 90 percent reduction in Hg emissions is possible from new IGCC units based on the use of carbon bed technology. Therefore, EPA is proposing this 90 percent Hg reduction as a beyond-the-floor level for new IGCC units.

The EPA requests comment on whether such use of a sorbent bed to remove Hg from coal syngas is an appropriate beyond-the-floor option. Comments should include information on emissions, control efficiencies, reliability, current demonstrated applications, and costs.

Coal refuse-fired units. Because existing units utilizing 100 percent coal refuse, all of which utilize FBC technology, have demonstrated the best Hg control of any emission-tested electric utility unit in the industry, EPA requests comments on whether there are any additional control techniques that have been demonstrated and can be applied to refuse coal-fired units to consistently achieve emission levels that are lower than those of similar sources achieving the proposed new MACT floor level of control. Comments should include information on emissions, control efficiencies, reliability, current demonstrated applications, and costs.

Oil-fired units. There has not been a new oil-fired unit constructed in the U.S. since 1981. If a new oil-fired unit is constructed, the only technology that might offer emissions control better than the proposed new unit MACT limits is the use of fabric filtration, which, as is discussed for existing sources elsewhere in this preamble, EPA does not consider to be a viable control option for oil-fired units.

The EPA requests comments on whether the use of fabric filters should be considered as a beyond-the-floor option for new oil-fired units and whether these or other control techniques could be used to consistently achieve emission levels that are lower than those from similar sources achieving the proposed new MACT floor level of control. Comments should include information on emissions, emissions reductions, reliability, current demonstrated applications, and costs.

Additional information on the beyond-the-floor analyses for new units is available in the document titled, "Beyond the Floor Analysis for Existing and New Coal- and Oil-Fired Electric Utility Steam Generating Units NESHAP" which can be found in the docket.

10. How Did EPA Select the Proposed Testing and Monitoring Requirements?

The CAA requires EPA to develop regulations that ensure initial and continuous compliance. Testing and monitoring requirements allow EPA to determine whether an affected source is operating in compliance with an applicable emission limitation/standard. This section discusses how EPA selected the proposed testing and monitoring requirements used to determine compliance with the Hg emission limits for coal-fired units and the Ni emission limits for oil-fired units that are specified in the proposed rule.

Mercury testing and monitoring requirements. The proposed rule would establish Hg emission limits for coal-fired units. The format selected for these Hg emission limits is a 12-month rolling average Hg emission level expressed in units of lb/TBtu or lb/MWh. Therefore, appropriate testing or monitoring requirements for determining the amount of Hg emitted from an affected unit throughout the compliance averaging period must be included in the rule.

The most direct means of demonstrating compliance with an emission limit is by the use of a CEMS that measures the pollutant of concern. The EPA considers other testing or monitoring options when acceptable CEMS are not available for the intended application or when the impacts of including such CEMS requirements in the proposed rule are considered by EPA to be unreasonable. In determining whether to require the use of other testing or monitoring options in lieu of CEMS, it is often necessary for EPA to balance more reasonable costs against the quality or accuracy of the actual emissions data collected.

There are several approaches to Hg monitoring that EPA has identified for possible use in this rule to determine compliance with the proposed Hg emission limits. One option is to use a CEMS that combines both automated sampling and analytical functions in a single system to provide continuous, real-time Hg emission data. Mercury CEMS are currently available from several manufacturers. These Hg CEMS are similar to most other types of instruments used for continuous monitoring of pollutants from combustion processes, in that the combustion gas sample is first extracted from the stack and then transferred to an analyzer for analysis. In general, the Hg CEMS now available can be distinguished by the Hg measurement detection principle used (*e.g.*, atomic adsorption, atomic fluorescence, x-ray fluorescence). Capital costs for a Hg CEMS are currently estimated to range from approximately $95,000 to $135,000, depending on the manufacturer and model selected. The annual costs to operate and maintain a Hg CEMS are estimated to range from $45,000 to $65,000, again depending on the manufacturer and model selected.

A second option is to use a long-term sampling method that collects a cumulative Hg sample by continuously passing a low-flow sample stream of the combustion process flue gas through a Hg trapping medium (*e.g.*, an activated carbon tube). This sampling tube is then periodically removed (*e.g.*, after a day or up to 1 month) and replaced with a tube filled with fresh trapping medium. The removed sampling tube is then sent to a laboratory where the trapping medium is analyzed for its Hg content. This method, like using a Hg CEMS, is capable of providing data on the Hg emissions from a combustion process on a continuous basis, but unlike a Hg CEMS, the data are not reported on a real-time basis. Using the long-term sampling method, the Hg collected in the sampling tube is integrated over a much longer sampling period (*i.e.*, 1 to 7 days for the AC tube versus less than 15 minutes for the CEMS). The capital cost for a gas metering system and Hg trapping medium is estimated to be approximately $18,000. The annual costs for periodic sampling tube replacement and for the laboratory Hg analysis range from approximately $65,000 to $125,000 depending upon quality assurance and quality control (QA/QC) requirements and frequency of sample tube replacement.

Finally, a third monitoring option is to use one of the manual stack test methods available for measuring Hg emissions from combustion processes on an intermittent basis. The existing voluntary consensus stack test method ASTM Method D6784–02 (commonly known as the Ontario-Hydro method) is currently the method of choice for measuring Hg species in the flue gas from Utility Units. Another method for measuring total (*i.e.*, not speciated) Hg is EPA Reference Method 29. This method involves a technician extracting a representative flue gas sample over a relatively short period of time (*e.g.*, a few hours) using a sampling train consisting of a nozzle and probe, a filter to collect particulate matter, and a liquid solution and/or reagent to capture gas-phase Hg. After sampling, the filter and sorption media are prepared and analyzed for Hg in a laboratory. These test methods could be applied to a Hg monitoring program at electric utility plants by performing a manual stack test using ASTM Method D6784–02 or EPA Reference Method 29 at some specified periodic interval throughout the compliance averaging period (*e.g.*, perform a stack test daily, weekly, biweekly, monthly). The cost to conduct a single ASTM Method D6784–02 typically ranges from $15,000 to $17,000 depending on site conditions. Annual costs will depend on the frequency with which the stack test is required to be performed during the compliance averaging period. For example, if the test is required once per week, the total annual cost would be as much as $780,000 (52 tests in a 12-month period at $15,000 per test).

The EPA evaluated each of the above Hg monitoring options with respect to its suitability for the measurement of the Hg emission data needed for determining compliance with the 12-month rolling average Hg emission limit. The EPA rejected from further consideration the third option, intermittent monitoring using manual stack test methods. Use of this monitoring approach would place significantly higher labor requirements and monitoring costs on facility owners/operators than the other two options in order to perform an adequate number of source tests throughout the compliance averaging period to demonstrate with reasonable confidence that the applicable Hg emission limit value was being achieved.

Both of the remaining two options would provide the necessary data to calculate the total Hg emissions from an affected source for each 12-month compliance averaging period. While the CEMS would provide these data on a real-time basis, EPA concluded that having real-time data is not mandatory for determining compliance with an emission limit based on a 12-month rolling average. Total Hg emissions from an affected source by month are needed to compute the rolling 12-month average Hg emission value. With regular scheduled replacement and timely analysis of sampling tubes, total monthly Hg emissions can readily be obtained using the long-term sampling method.

The EPA then compared the costs of applying the Hg CEMS and long-term monitoring options to Utility Units. While the CEMS have significantly higher capital costs, the automated analyses directly by the instrument eliminates the need and cost for separate analyses of the collected sampling tubes in a laboratory required by the long-term sampling method. Overall, EPA determined that the total costs of using either monitoring method to determine compliance would be similar for a given site. Selection of which monitoring method should be used at the site will depend on site-specific conditions and owner/operator preferences. Because both monitoring methods will collect the Hg emission data necessary to determine compliance with the proposed Hg emission limit and the costs of either option are reasonable, EPA decided to allow the owner/operator flexibility under the proposed rule to choose to use either Hg CEMS or long-term sampling monitoring as best suits their site conditions and preferences.

An owner/operator electing to use a CEMS to comply with the rule would be allowed to use any CEMS that meets the requirements in "Performance Specification 12A, Specifications and Test Procedures for Total Vapor-phase Mercury Continuous Monitoring Systems in Stationary Sources" (PS–12A). This performance specification is proposed as part of this rulemaking and we request comment on continuous monitoring of Hg emissions according to the requirements in the proposed performance specification.

Those owners/operators electing to use long-term Hg monitoring would be required to follow the requirements in Method 324, "Determination of Vapor Phase Flue Gas Mercury Emissions from Stationary Sources Using Dry Sorbent Trap Sampling" when it is promulgated. Method 324 is proposed as part of this rulemaking to be added to 40 CFR part 63, appendix A. We request comments on the requirements in proposed Method 324 for Hg measurement using long-term sampling. The owner/operator would use the procedures outlined in § 63.10009 of the proposed rule to convert the concentration output from a CEMS or Method 324 to an emission rate format in lb/TBtu or lb/MWh.

Continuous compliance requirements are required under every NESHAP so that EPA can determine whether an affected source remains in compliance with the applicable emission limitation/standard following the initial compliance determination. In the case of the proposed Utility NESHAP, the format for the Hg emission limit is a 12-month rolling average limit. The same monitoring requirements used to establish initial compliance of an affected electric utility unit with the applicable Hg emission limit at the end of the first 12-month period following the facility's compliance date serve to demonstrate continuous compliance with the Hg emission limit with the computation of each new 12-month rolling average value each month thereafter. Thus, no additional continuous compliance Hg monitoring requirements beyond those previously discussed are required for the proposed rule.

The EPA is concerned about monitoring costs for Utility Units with low Hg emissions rates, and does not desire to adopt a monitoring scheme where the costs are disproportionate to the costs of compliance with the MACT emissions limitations. For these units (*e.g.*, those emitting under 25 pounds per year) the EPA may consider reduced monitoring frequencies and lower cost monitoring requirements, since the need for accuracy is reduced for such units. For example, the EPA is concerned about the merits of requiring an expenditure of $100,000 per year to monitor releases when the costs of substantive compliance is far less. The Agency requests comments and related data upon which to establish an alternate reporting scheme.

Nickel testing and monitoring requirements. The proposed rule would establish Ni emission limits for oil-fired units. The EPA selected a different format for the Ni emission limits than is proposed for the Hg emission limits. The Ni emission limits are maximum allowable emission limits not to be exceeded, expressed in lb/TBtu or lb/MWh.

The EPA selected the proposed testing requirements to determine compliance with the Ni emission limits under the NESHAP to be consistent with existing procedures used for the electric utility industry. Method 29 in appendix A to 40 CFR part 60 is an EPA reference test method that has been developed and validated for the measurement of Ni emissions from stationary sources. For sampling and analysis of the gas stream, the following EPA reference methods would be used with Method 29: Method 1 to select the sampling port location and the number of traverse points; Method 2 to measure the volumetric flow rate; Method 3 for gas analysis; and Method 4 to determine stack gas moisture. Method 19 specifies the procedure for collecting the necessary fuel data to be used with the Method 29 Ni measurements from the source test to compute the Ni emission rate expressed in units of lb/TBtu.

As an alternative under the proposed rule, an owner/operator of an existing source could choose to comply with the applicable Ni emission limit expressed in lb/MWh. The owner/operator would use the procedures outlined in § 63.10009 of the proposed rule to convert the concentration output of Method 29 to the output-based emission rate format.

To address the need for continuous compliance requirements for the proposed Ni emission limits, EPA considered the availability and feasibility of a number of Ni monitoring options ranging from direct monitoring of Ni emissions, to process parameter monitoring, to control device parameter monitoring. Monitors for continuously measuring Ni emissions have not been demonstrated in the U.S. for the purpose of determining compliance. Therefore, EPA did not consider further the use of continuous monitors for Ni for the proposed rule.

Another option used in other NESHAP for demonstrating continuous compliance is to monitor appropriate process and/or control equipment operating parameters. These parameters are established during the initial, and any subsequent, stack test. Process parameters were not selected as indicators for Ni emissions from Utility Units because a direct correlation does not exist between combustion or electricity production parameters and Ni emission rates from a given unit.

Monitoring of PM control device operating parameters is used in other NESHAP established for combustion processes and other source categories that include PM emission limits. The EPA decided to also use this continuous monitoring approach to demonstrate continuous compliance with the applicable Ni emission limits set forth in the proposed rule. The selected operating parameters for the PM control device used by oil-fired Utility Units (*e.g.*, ESP) are reliable indicators of control device performance. The EPA believes that reasonable assurance of compliance with the emission limits proposed for this NESHAP can be achieved through appropriate monitoring and inspection of the operation of the APCD that have been demonstrated by an initial performance test to achieve the applicable Ni emission limits under the rule.

Compliance calculations. For cogeneration units, steam is also generated for process use. The energy content of this process steam must also be considered in determining compliance with the output-based standard. This consideration is accomplished by taking the net efficiency of a cogeneration unit into account. Under a Federal Energy Regulatory Commission regulation, the efficiency of cogeneration units is determined from the useful power output plus one-half the useful thermal output (18 CFR 292.205). To account for the process steam energy contribution to net plant output, a 50-percent credit of the process steam heat is necessary. Such a credit would, EPA believes, provide an incentive for cogeneration.

Therefore, owners/operators of cogeneration units subject to the proposed rule would need to monitor the portion of their net plant output that is process steam so that they can take the 50-percent credit of the energy portion of their process steam net output. For example, a cogeneration unit subject to the rule measures its net electrical output over a compliance period, as 30,000 MWh. During the same period the unit burns coal that provides 750 billion Btu input to its furnace/boiler, and emits 0.2 lb Hg. Using equivalents found in 40 CFR 60 for electric utilities (*i.e.*, 250 million Btu/hr input to a boiler is equivalent to 73 MWe input to the boiler; 73 MWe input to the boiler is equivalent to 25 MWe output from the boiler; therefore, 250 million Btu input to the boiler is equivalent to 25 MWe output from the boiler) the 50-percent credit could be found as follows. The net output calculation would be 750 billion Btu × (25 MWe output/250 million Btu/hr input) = 75,000 MWh equivalent electrical output from the boiler over the compliance period. Of this amount, 30,000 MWh was produced as electricity sent to the grid, leaving 45,000 MWh as the energy converted to steam for process use. Half of this amount is 22,500 MWh. The unit's Hg CEM records a total of 0.2 lb Hg over the same compliance period. The adjusted Hg emission rate is then: 0.2 lb Hg/(30,000 MWh + 22,500 MWh) = 3.8×10^{-6} lb Hg/MWh.

11. How Did EPA Determine Compliance Dates for the Proposed Rule?

Section 112(i) of the CAA specifies the dates by which affected sources must comply with the emission standards. New or reconstructed units must be in compliance with the proposed rule immediately upon startup or [DATE THE FINAL RULE IS PUBLISHED IN THE **Federal Register**], whichever is later, except that if the final rule is more stringent than the proposal, a new source that commences construction before the final rule is promulgated may comply with the proposed rule for 3 years before complying with the final rule. Existing sources must be in compliance with the final rule 3 years after the effective date of the final rule. Existing sources may seek a permit granting an additional one year to comply if such time is necessary for the installation of controls.

We anticipate that a substantial number of sources would have to install control technologies to meet the limits of the proposed standard, if the CAA section 112 MACT rule is finalized. We also believe that such construction could be constrained by the potential impacts on electricity reliability, delays in obtaining permits, and other factors (including potential labor and equipment shortages). Thus, we anticipate that a substantial number of units will seek the 1-year extension which could unduly burden State and local permitting authorities. Therefore, EPA is soliciting comment on whether a 1-year extension should be granted for facilities required to install controls in order to comply with the proposed CAA section 112 MACT rule, should it be finalized.

12. How Did EPA Select the Proposed Recordkeeping and Reporting Requirements?

Under section 114(a) of the CAA, EPA may require owners/operators of affected sources subject to a NESHAP to maintain records as well as prepare and submit notifications and reports to the EPA. In addition, section 504(a) of the CAA mandates that sources required to obtain a title V permit submit a report setting forth the results of any required monitoring no less often than every 6 months. The general recordkeeping, notification, and reporting requirements for all NESHAP are specified in 40 CFR 63.9 and 40 CFR 63.10 of the General Provisions, if incorporated into the proposed rule. The recordkeeping, notification, and reporting requirements for the proposed rule were selected to include all of the applicable records, notifications, and reports specified by the General Provisions requirements. Additional requirements were included in the proposed rule that are necessary to ensure that a given affected source is complying with the emission limits from the correct subcategory.

The proposed rule would also require that the owner/operator keep monthly records for each affected source listing the type of fuel burned, the total fuel usage, and the fuel heating value. Additional recordkeeping would be required for those owners/operators electing to comply with a fuel blending emission limit. The owner/operator would be required to maintain records of all compliance calculations and supporting information.

13. Will EPA Allow for Facility-Wide Averaging?

The proposed rule contains provisions allowing the owner/operator of a coal-fired affected unit to demonstrate compliance through the averaging of Hg emissions from multiple affected units located at a common, contiguous facility site. Consistent with EPA policy on regulatory flexibility, this provision is intended to provide a facility with the benefit of operational flexibility while still meeting the proposed emission limitations and achieving the required emissions reductions. This averaging provision effectively allows the owner/operator to average the emissions from multiple (two or more) coal-fired affected units and comply with one applicable facility-wide emission limitation.

The proposed rule would require that any coal-fired affected unit included in the facility's averaging regime be a regulated unit under the proposed rule (*i.e.*, coal-fired Utility Units only, and not combined with sources regulated by other rules, such as IB units).

The averaging provision may be applied to meet the proposed emission limitations for Hg from coal-fired units. An important aspect of this provision is that the emissions measurements for the averaging calculations are taken after the last control device. Affected units that share a common control device are inherently averaged by the standard compliance calculations provided in § 63.10009 of the proposed rule. It is the intention of EPA to provide additional flexibility to average all coal-fired units at one facility into one averaged emission limit. In accordance with that intent, the initial and continuous compliance demonstration under this averaging provision would be to determine the emission rate applicable to all affected units (which may be individual or blended) according to requirements under § 63.10009 and then use those limits to calculate a limit for the emissions averaging group according to § 63.99991 of the proposed rule.

The owner/operator would be required to limit Hg emissions from the group of all affected units being averaged to an overall Hg emission limit (emissions-averaged emission limit, AvEL) during each 12-month compliance period. The owner/operator would be required to use the AvEL determined in accordance with § 63.99991 of the proposed rule throughout the 12-month compliance period and may not switch between compliance with individual subcategory emission limits and an AvEL. The format of the AvEL (lb/MWh or lb/TBtu) would also be required to remain constant throughout the 12-month compliance period. The owner/operator would keep all records as required by sections 63.10031 and 63.10032 of the proposed rule. The owner/operator would be required to submit information on the affected units which comprise each AvEL group for which the owner/operator used a calculated AvEL; the emission limits (including format) that would be averaged (*i.e.*, Hg); the units that will be averaged together; and the calculation of the AvEL with which the averaged units will comply. The owner/operator may implement emissions averaging at any time after the effective date with submission of the averaging plan. The owner/operator must revise the plan to change an emissions averaging group. The owner/operator must certify in each semiannual compliance report that the AvEL group of affected units was in compliance with the emission limitation.

The EPA solicits comment on the emissions averaging provision, particularly on the usefulness of the provision and its specific applicability requirements.

III. Proposed Revision of Regulatory Finding on the Emissions of Hazardous Air Pollutants from Electric Utility Steam Generating Units

A. What Action Is EPA Taking Today?

Today, EPA proposes revising the regulatory finding that it published on December 20, 2000 (65 FR 79825) pursuant to section 112(n)(1)(A) of the CAA. The EPA is proposing such a revision based on its review of the December 2000 finding, the Utility RTC underlying that finding, and the provisions of the CAA. For the reasons discussed below, EPA proposes to find that regulation of coal- and oil-fired Utility Units under section 112 is not "appropriate and necessary" within the meaning of section 112(n)(1)(A). As a consequence, EPA also proposes to delete such units from the CAA section 112(c) list. The EPA does not propose revising its December 2000 conclusion with regard to HAP emissions from natural-gas fired electric utility steam, however, as it continues to believe that regulation of such units is not appropriate and necessary.

What was EPA's December 2000 "necessary" finding? Was EPA's December 2000 "necessary" finding overbroad? As noted above, in December 2000, EPA concluded that it was

> "necessary to regulate HAP emissions from coal- and oil-fired electric utility steam generating units under section 112 of the CAA because the implementation of other requirements under the CAA will not adequately address the serious public health and environmental hazards arising from such emissions." (65 FR 79830)

Upon further review of the record and the December 2000 notice, EPA believes that this finding is over-broad in two respects.

First, the "necessary" finding might be interpreted to suggest that all HAP emissions from coal- and oil-fired Utility Units pose "serious public health * * * hazards." (65 FR 79830) Upon further review of the record, EPA recognizes that it could not reasonably have reached such a conclusion based on the record before it in December 2000. That record supports only a finding that emissions of Hg and Ni warrant regulation. Nothing in the Study or the information EPA obtained following that study even arguably supports the proposition that EPA should address HAP emissions from Utility Units other than emissions of Hg and Ni.

Second, the "necessary" finding states that emissions of HAP from Utility Units result in "serious * * * *environmental hazards*." (*See* 65 FR 79830.) (emphasis added.) After re-examining the record, EPA recognizes that this conclusion also cannot be supported by the record. As an initial matter, the Utility RTC, consistent with CAA section 112(n)(1)(A), focused solely on hazards to public health, not the environment. In fact, the Study expressly states that the ecological impacts associated with HAP from Utility Units were not examined because such impacts were beyond the scope of the Study mandated by CAA section 112(n)(1)(A)) (ES at 27). The only information in the record concerning the effects of HAP on the environment was for Hg, and that information was obtained after completion of the Utility RTC. Thus, given the record before the Agency in December 2000, the most EPA could have intended to state in the December 2000 "necessary" finding is it is necessary to regulate Hg from coal-fired Utility Units and Ni from oil-fired Utility Units because the implementation of other requirements under the CAA will not adequately address the serious public health hazards arising from such emissions or the environmental hazards associated with Hg. Moreover, as explained below, EPA has recently re-analyzed this "necessary" determination and the premise underlying that determination.

Does other CAA authority exist to address emissions of Hg and Ni from coal- and oil-fired Utility Units? The EPA continues to believe that emissions of Hg from coal-fired Utility Units and emissions of Ni from oil-fired units pose hazards to public health, that coal-fired Utility Units are the largest domestic source of Hg emissions, and that oil-fired units are the primary source of Ni emissions. These findings support a determination that it is appropriate to regulate emissions of Hg and Ni from Utility Units.

We have had an opportunity to re-assess the "necessary" finding made in December 2000. Today, we propose to revise that finding because, after examining the scope of available authorities under the CAA, we have determined that there is, in fact, another viable statutory mechanism that would adequately address Hg and Ni emissions from coal- and oil-fired Utility Units. That authority is CAA section 111.

The scope of existing authorities under the CAA. The EPA interprets the language of CAA section 112(n)(1)(A) and the limited legislative history relating to that provision as indicating Congress' intent that Utility Units be regulated under section 112 only if the other authorities of the CAA, once implemented, would not adequately address those HAP emissions from Utility Units that warrant regulation. This interpretation is supported by the first sentence of section 112(n)(1)(A), which requires EPA to conduct a study that focuses on the hazards to public health that would exist following implementation of the other authorities of the CAA. It is further evidenced by the final sentence of section 112(n)(1)(A), which calls for regulation of Utility Units under section 112 only if, based on the results of the Study, EPA determines that it is both appropriate and necessary to regulate such units. Finally, the remarks made by Congressman Oxley, a member of the conference committee, concerning the Conference Report on the CAA Amendments of 1990, confirm that Congress sought to regulate under section 112 "only those units [Utility Units] that * * * (the Administrator) determines—after taking into account compliance with all other provisions of the act * * *—have been demonstrated to cause a significant threat of serious adverse effects on public health." [7] (136 Cong. Rec. E3670, 3671 & H12911, 12934 (daily ed. Nov. 2, 1990) (Statement of Congressman Oxley)

Based on the foregoing, EPA believes if we make a determination under section 112(n)(1)(A) that it is appropriate to regulate Utility Units, we are not compelled to regulate Utility Units under section 112 if other authorities in the CAA exist to adequately address health hazards that occur as a result of HAP emissions. The EPA believes that this is a reasonable interpretation of the term "necessary" in CAA section 112(n)(1)(A), and that it is wholly consistent with its interpretation of the term in December 2000. (*See* 65 FR 79830. "It is necessary to regulate * * * under section 112 of the CAA because the implementation of other requirements under the CAA will not adequately address the serious public health and environmental hazards arising from such emissions * * *")

Since December 2000, EPA has had the opportunity to conduct a more thorough review of the available authorities under the CAA. Based on that review, EPA has identified a provision of the CAA that it believes can be employed to adequately address the hazards to public health resulting from Hg and Ni emissions from Utility Units. That provision is CAA section 111, which authorizes EPA to develop standards of performance for new and existing sources of air pollutants that cause, or contribute significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.

The EPA based its "necessary" finding in December 2000 solely on its belief, at the time, that there were no other authorities under the CAA that would adequately address Hg and Ni emissions from coal- and oil-fired Utility Units. Now that we have re-examined the scope of existing authorities under the CAA and identified a viable statutory mechanism other than section 112, we propose to revise the December 2000 "necessary" finding accordingly. We specifically propose to find that regulation of coal- and oil-fired Utility Units under section 112 is *not* necessary because CAA section 111, once implemented, would adequately address the public health hazards posed by Utility Unit emissions of Hg and Ni.[8]

We further believe that CAA section 111, once implemented, would adequately address any environmental effects associated with Hg emissions from Utility Units, as documented in the record. We recognize that the plain language of CAA section 112(n)(1)(A) requires an examination solely of hazards to public health associated with HAP emissions, not of hazards to the environment. Nevertheless, in this case, and given that the December 2000 finding addresses both the health and environmental effects of Hg, we believe that our section 111 proposal would adequately address both of those effects.

Regulation under CAA section 111. Overview. The two relevant provisions of section 111 are section 111(b), which applies to new sources, and section 111(d), which applies to existing sources. As explained below, EPA believes that these provisions authorize the establishment of standards of performance both for Hg emissions from new and existing coal-fired Utility Units and for Ni emissions from new and existing oil-fired units, and that such standards, once finalized, would adequately address the health hazards resulting from Hg and Ni emissions. Indeed, through this notice, EPA proposes such standards of performance. We explain below why the proposed standards adequately address any public health hazards resulting from Hg and Ni emissions from Utility Units and the environmental effects associated with Hg emissions.

Regulation under section 111(b). Pursuant to CAA section 111(b)(1)(A), EPA has established a list of stationary source categories. The EPA is to include a source category on the section 111(b) list if it determines that such category causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare. Section 111(b) further requires EPA to establish federal standards of performance for new sources within each listed source category.

The EPA included Utility Units on the section 111(b) list of stationary sources in 1979. (44 FR 33580; June 11, 1979.) The EPA has also previously promulgated federal standards of performance for such units for pollutants like NO_X, PM, and SO_2. (*See* subpart Da of 40 CFR part 60.)

Nothing in section 111(b) precludes EPA from promulgating additional standards of performance for other pollutants emitted from new Utility Units. Indeed, where, as here, EPA has determined that emissions of Hg and Ni from coal- and oil-fired Utility Units warrant regulation, the establishment of Federal standards of performance under section 111(b) is appropriate.

Moreover, nothing in CAA section 111 or section 112 indicates that Congress sought to regulate HAP exclusively under section 112. Rather, the language of sections 112(c)(6), 112(d)(7) and 112(n)(1)(A) supports the conclusion that HAP emissions could be regulated under other provisions of the CAA. There is nothing in the legislative history to suggest that Congress sought to preclude EPA from regulating HAP under other sections of the Act. We, therefore, believe that CAA section 111(b), as amended in 1990, constitutes a viable and appropriate statutory authority by which to regulate Hg emissions from new coal-fired Utility Units and Ni emissions from new oil-fired units.

[7] Congressman Oxley further noted that regulation under CAA section 112 should be imposed "only if warranted by the scientific evidence." 136 Cong. Rec. E3670, 3671 & H12911, 12934 (daily ed. No. 2, 1990) (Statement of Congressman Oxley).

[8] The EPA examined various provisions of the CAA, including section 111, prior to issuing its December 2000 regulatory finding. (Utility RTC.) At that time, we did not believe that any other provisions of the CAA would adequately address the health hazards of concern associated with Hg and Ni emissions. Now, after re-analyzing the provisions of the CAA, we recognize that CAA section 111 is a viable statutory mechanism that would adequately address Hg and Ni emissions from coal- and oil-fired units. The premise underlying our December 2000 "necessary" finding, therefore, lacks foundation. Nothing precludes EPA from revisiting its December 2000 "necessary" determination, particularly, where, as here, the basis for that determination involved the scope of existing statutory provisions and those provisions have not changed substantively since 1990.

Regulation under section 111(d). CAA section 111(d), unlike section 111(b), specifically references CAA section 112. The import of that reference is not clear, however, because Public Law 101–549, which is the 1990 amendments to the CAA, contains two different and conflicting amendments to section 111(d). To understand this conflict, it is useful to start with the language of section 111(d) as contained in the 1977 Amendments to the CAA.

In 1977, section 111(d)(1) read as follows:

> The Administrator shall prescribe regulations which shall establish a procedure similar to that provided by section 7410 of this title under which each State shall submit to the Administrator a plan which (A) establishes standards of performance for any existing source for any air pollutant (i) for which air quality criteria have not been issued or which is not included on a list published under section 7408(a) or 7412(b)(1)(A) of this title, but (ii) to which a standard of performance under this section would apply if such existing source were a new source. * * *

This language provides that standards of performance should not be established under section 111(d) with respect to any pollutants that are listed as hazardous air pollutants under section 112(b)(1)(A) of the 1977 CAA.

In the 1990 Amendments to the CAA, two different and conflicting amendments to section 111(d) were enacted. Presumably, Congress did not realize that it had passed two different amendments to the same statutory provision. The first amendment, which is the House amendment, is contained in section 108(g) of Public Law 101–549. That section amends section 111(d)(1)(A)(i) of the 1977 CAA by striking the words "or 112(b)(1)(A)" from the 1977 CAA and inserting in its place the following phrase: "or emitted from a source category which is regulated under section 112." The second amendment to section 111(d), which is the Senate amendment, is labeled a "conforming amendment" and is set forth in section 302 of Public Law 101–549. That section amends CAA section 111(d)(1) of the 1977 CAA by striking the reference to "112(b)(1)(A)" and inserting in its place "112(b)."

These two amendments are reflected in parentheses in the Statutes at Large as follows:

> The Administrator shall prescribe regulations which shall establish a procedure similar to that provided by section 7410 of this title under which each State shall submit to the Administrator a plan which (A) establishes standards of performance for any existing source for any air pollutant (i) for which air quality criteria have not been issued or which is not included on a list published under section 7408(a) (or emitted from a source category which is regulated under section 112) (or 112(b)), but (ii) to which a standard of performance under this section would apply if such existing source were a new source. * * *

EPA recognizes that the United States Code does not contain the parenthetical reference to the Senate amendment in section 302 of Public Law 101–549; the codifier's notes to this section state that the Senate amendment "could not be executed" because of the other amendment to section 111(d) contained in the same Act. The United States Code does not control here, however. The Statutes at Large constitute the legal evidence of the laws, where, as here, title 42 of the United States Code, which contains the CAA, has not been enacted into positive law. See 1 U.S.C. 204(a); *United States* v. *Welden,* 377 U.S. 95, 98 n.4 (1964); *Washington-Dulles Transportation Ltd.* v. *Metropolitan Washington Airports Auth.*, 263 F.3d 371, 378 (4th Cir. 2001).

A literal reading of the House amendment, as contained in the Statutes at Large, is that a standard of performance under CAA section 111(d) cannot be established for any air pollutant that is emitted from a source category regulated under section 112. Under this reading, EPA could not regulate, under CAA section 111(d), HAP *and non-HAP* emissions that are emitted from a source category regulated under section 112. A literal reading of the Senate amendment is that a standard of performance under section 111(d) cannot be established for any HAP that is listed in section 112(b)(1), regardless of what categories of sources of that pollutant are regulated under section 112. The House and Senate amendments conflict in that they provide different standards as to the scope of EPA's authority to regulate under section 111(d).

Over the years, EPA has identified other conflicting provisions of the CAA. See, *e.g., Citizens to Save Spencer County* v. *EPA*, 600 F.2d 844 (D.C. Cir. 1979). Consistent with principles of statutory construction, the Agency has always sought to harmonize such conflicting provisions, where possible, and to adopt a reading that gives some effect to both provisions. The first step in this process involves an evaluation of what Congress intended by each amendment. This step is difficult here because of the absence of legislative history directly addressing the amendments. For that reason, we focus on the plain language of the amendments.

The Senate language reflects the Senate's intent to retain the pre-1990 approach of precluding regulation under CAA section 111(d) for any HAP that is listed under section 112(b). The Senate's intent is further demonstrated by the fact that the amendment itself it labeled a "conforming amendment," which is generally a non-substantive amendment. By contrast, the House amendment was not a conforming amendment. Rather, the House changed the focus of CAA section 111(d) and sought to preclude only regulation of pollutants emitted from a source category that is actually regulated under section 112. One reasonable interpretation is that the House amendment reflects a desire to change the pre-1990 approach and to expand EPA's authority as to the scope of pollutants that could be regulated under section 111(d). One possible reason for this change is that the House did not want to preclude EPA from regulating under section 111(d) those pollutants emitted from source categories which were not actually being regulated under section 112. Such a reading of the House language would authorize EPA to regulate under section 111(d) existing area sources which EPA determined did not meet the statutory criterion set forth in section 112(c)(3), as well as existing Utility Units.

One way to harmonize the Senate and House amendments is to interpret them as follows: Where a source category is being regulated under section 112, a section 111(d) standard of performance cannot be established to address any HAP listed under 112(b) that may be emitted from that particular source category. Thus, if EPA is regulating source category X under section 112, section 111(d) could not be used to regulate HAP emissions from that particular source category.

We believe that this is a reasonable interpretation as it gives some effect to both amendments. First, it gives effect to the Senate's desire to focus on HAP listed under section 112(b), rather than applying the section 111(d) exclusion to non-HAP emitted from a source category regulated under section 112, which a literal reading of the House amendment would do. Second, it gives effect to the House's apparent desire to increase the scope of EPA's authority under section 111(d) and to avoid duplicative regulation of HAP for a particular source category. We recognize that our proposed reconciliation of the amendments does not give full effect to the House's language, because a literal reading of the House language would mean that EPA could not regulate both HAP and non-HAP from a source category regulated under section 112. Such a reading would be inconsistent with the general thrust of the 1990 amendments, which, on balance, reflects Congress's desire to require EPA to regulate more substances, not to eliminate EPA's ability to regulate large categories of pollutants like non-HAP. Furthermore, EPA has historically regulated non-HAP under section 111(d), even where those non-HAP were emitted from a source category actually regulated under section 112. See, *e.g.*, 40 CFR 62 1100 (California State Plan for Control of Fluoride Emissions from Existing Facilities at Phosphate Fertilizer Plants). We do not believe that Congress sought to eliminate regulation for a large category of sources in the 1990 Amendments and our proposed interpretation avoids this result.

Finally, we believe that the proper inquiry for assessing whether to revise the December 2000 "necessary" finding is whether CAA section 111(d) constituted a viable statutory authority by which to address Hg and Ni emissions from existing coal- and oil-fired Utility Units as of 1998, the date on which EPA completed the Utility RTC. The answer, we believe, is yes. At that time, Utility Units were not listed under section 112, which consistent with our proposed interpretation of the conflicting amendments would allow us to regulate HAP from existing sources of such units under CAA section 111(d). The EPA, therefore, believes that it has the authority, and that it had the authority in 1998 when it completed the Utility RTC, to regulate Hg emissions from existing coal-fired Utility Units and Ni emissions from existing oil-fired units pursuant to section 111(d).

Adequacy of regulation under section 111. Adequacy of regulatory methods. The EPA proposes to conclude that section 111 offers adequate regulatory authority to control Hg and Ni emissions from both existing and new coal- and oil-fired Utility Units. For existing sources, subsection (d) of section 111 authorizes EPA to promulgate "standards of performance" that States must include in SIP-like plans applicable to those sources. The term "standard of performance" is defined in section 111(a)(1) as—

> a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.[9]

The EPA believes that the gravamen of this definition is the phrase, "best system of emission reduction." While the parenthetical following this phrase obligates EPA to consider the factors specified in that parenthetical, the term "best system" is not defined, and implicitly accords broad discretion to the Administrator, which includes the demonstration of such systems. The term "system" implies a broad set of controls, and the term "best" confers upon the Administrator the authority to promulgate regulations requiring controls that he considers superior. Moreover, except that the parenthetical phrase in the definition mandates consideration of certain factors, the definition provides no other explicit constraints in determining the "best system." Therefore, EPA believes that in developing the "best system of emission reduction," the Administrator must consider cost, non-air quality health and environmental factors, as well as energy requirements; and that he is authorized to consider, at his discretion, human health and environmental impacts, air quality impacts, timing and feasibility of control factors, and other factors.

This broad authority conferred on the Administrator means that section 111 constitutes an adequate mechanism for regulating Hg emissions from coal-fired Utility Units, and Ni from oil-fired units. Because the Administrator may consider a broad range of factors in developing standards of performance under section 111, the Administrator has the authority to develop control levels to address the emissions of Hg and Ni that warrant regulation.

Specifically, as described elsewhere in this notice, EPA is proposing today standards of performance for regulating Hg and Ni emissions from certain sources. In the case of Ni, EPA is proposing emission rate requirements to address emissions from oil-fired Utility Units. The basis for these standards of performance is discussed elsewhere in today's notice.

In the case of Hg, EPA is proposing a "cap-and-trade" program for emissions of Hg from existing Utility Units. Mercury emissions, on a nationwide basis would, in effect, be capped at a specified level. This cap assures permanent reductions in Hg emissions, which an emissions rate control requirement cannot, in-and-of-itself, assure. States would be allocated specified amounts of Hg allowances—that is authorizations to emit a unit of Hg—which the States would then allocate to their Utility Units. The Utility Units would be permitted to emit Hg up to the amount of their allowances. The trading feature of this program would allow Utility Units to purchase or sell allowances, and adjust their emissions accordingly.

The basis for the 2010 and 2018 caps is discussed elsewhere in today's notice. Moreover, the authorization to trade allows implementation of the emissions cap in the most cost-effective manner. Thus, the cap provides health protection by limiting overall emissions, but in a cost-effective manner.

The EPA recognizes, however, that the overall cap level may not eliminate the risk of unacceptable adverse health effects of Hg emissions. Moreover, a cap-and-trade program raises the possibility that any particular utility may opt to purchase allowances, instead of implementing controls, and that this may result in continued Hg emissions at the previous, uncontrolled levels from that Utility Unit. These emissions may have adverse health impacts within the local area. The EPA recognized this issue in its initial 112(n) finding, when it stated:

> There is considerable interest in an approach to mercury regulation for power plants that would incorporate economic incentives such as emissions trading. Such an approach can reduce the cost of pollution controls by allowing for least-cost solutions among a universe of facilities that face different control costs. Trading also can allow for a greater level of control overall because it offers the opportunity for greater efficiency in achieving control. The EPA, however, recognizes and shares concerns about the local impacts of mercury emissions and any regulatory scheme for mercury that incorporates trading or other approaches that involve economic incentives must be constructed in a way that assures that communities near the sources of emissions are adequately protected. Thus, in developing a standard for utilities, the EPA should consider the legal potential for, and the economic effects of, incorporating a trading regime under section 112 in a manner that protects local populations.

(Regulatory Finding on the Emissions of Hazardous Air Pollutants From Electric Utility Steam Generating Units, FR 65 at 79830 and 65 FR 79831).

To assure that the overall cap level, and the pattern of Hg emissions resulting from the trading program, will be adequately protective, EPA proposes today to couple this program with an evaluation of whether Hg emissions remaining after compliance with the cap-and-trade requirements would cause unacceptable adverse health effects. That is, after implementation of the control requirements by 2010 and by 2018, EPA will evaluate the emission levels, attendant health risks, and

[9] The term, "standard of performance" is also defined in section 302(l), although there may be uncertainty about whether that defintion applies to the term as used under section 111. For purposes of this discussion, the section 302(l) defintion is not material.

available control mechanisms and determine whether the actual reductions achieved under this program significantly differ from the outcome predicted by our current analysis. The EPA retains the authority to revise its conclusions as to what constitutes the "best system" of emissions reductions for existing sources, and, therefore, to revise the standard of performance, to require additional reductions or controls to address such risks, based on information that would justify selection of a tighter regulatory regime.

Similarly, EPA intends to evaluate whether, following implementation of the controls on Ni emissions from existing oil-fired units, adverse health effects might remain from Ni emissions. As described above, EPA retains authority under section 111(d) to promulgate additional requirements on Ni emissions to address those health effects.

The EPA believes that these overall standards of performance for existing Utility Unit sources of Hg and Ni coupled with authority to evaluate remaining health risks and conduct further rulemaking, adequately address all health effects from Hg emissions that warrant regulation from existing coal-fired Utility Units and Ni emissions from existing oil-fired units as well as the environmental effects of Hg.

As to new sources, section 111(b)(1)(B) authorizes EPA to promulgate "standards of performance" directly regulating new sources. The section 111(a)(1) definition of "standard of performance" applies to these regulations, and thereby authorizes EPA to consider the same range of factors described above, including, for example, human health and environmental factors as well as technological and feasibility factors. Upon consideration of these factors, EPA proposes a technology-based set of controls for Hg emissions from new coal-fired Utility Units and Ni emissions from new oil-fired units. The basis for these controls is discussed elsewhere in today's notice. Further, section 111(b) provides adequate authority for EPA (i) to evaluate whether, following compliance with the new source standards, remaining Hg and/or Ni emissions result in unacceptable adverse health impacts; and, if so, (ii) to revise the standards of performance to include additional restrictions for those emissions. As a result, for new sources of both Hg and Ni emissions, as in the case of existing sources, section 111 provides regulatory authority that will adequately address all adverse health (and environmental) effects of concern.

Time for implementation. Why does regulation under section 111 adequately address the hazards of concern to public health associated with Hg and Ni emissions? This action is one part of a broader effort to issue a coordinated set of emissions limitations for the power sector. Today's rule would establish a mechanism by which Hg emissions from new and existing Utility Units would be capped at specified, nation-wide levels. A first phase cap would become effective in 2010 and a second phase cap in 2018. Facilities would demonstrate compliance with the standard by holding one "allowance" for each ounce of Hg emitted in any given year. Allowances would be readily transferrable among all covered facilities. We believe that such a "cap and trade" approach to limiting Hg emissions is the most cost effective way to achieve the reductions in Hg emissions from the power sector that are needed to adequately protect human health and the environment.

The added benefit of this approach is that it dovetails well with the SO_2 and NO_X IAQR published elsewhere in today's **Federal Register**. This rule would establish a broadly-applicable cap and trade program that would significantly limit SO_2 and NO_X emissions from the power sector. The advantage of regulating Hg at the same time and using the same mechanism as SO_2 and NO_X is that significant Hg emissions reductions can and will be achieved by the air pollution controls designed and installed to reduce SO_2 and NO_X. In other words, Hg is reduced as a "co-benefit" of controlling SO_2 and NO_X. Thus, the coordinated regulation of Hg, SO_2, and NO_X allows Hg reductions to be achieved in a particularly efficient and cost effective manner.

In theory, the "co-benefit" argument could work in both directions: controlling Hg also controls SO_2 and NO_X; controlling SO_2 and NO_X also controls Hg. In deciding how regulatory deadlines influence how investments in controls are sequenced, it makes much more sense to lead with SO_2 and NO_X controls, which are well established, than to lead with Hg controls, which are only at the beginning stages of commercialization. Overly ambitious Hg mandates in the near-term could actually hamper innovation toward more effective and less costly technologies. The quantified health benefits of NO_X and SO_2 are also larger and more certain.

The cap and trade approach to regulating Hg emissions offers certain other advantages over the unit-by-unit or facility-by-facility approach that we have traditionally employed under section 112. For example, a cap and trade system establishes fixed emissions caps that cannot be exceeded, even when existing plants are expanded and new plants are constructed. Thus, the cap provides absolute certainty with regard to national emissions. In contrast, a section 112 rule would limit the emissions of individual units or facilities, but would not limit overall emissions to the environment from the sector.

Another advantage of concurrently regulating Hg and SO_2 is derived from the fact that companies will have the opportunity under the SO_2 cap to generate extra allowances by achieving early reductions. For example, the first phase SO_2 cap under the transport rule becomes effective in 2010. Prior to that year, companies have an incentive to achieve greater SO_2 reductions than needed to meet the current Acid Rain cap because the excess allowances they generate can be "banked" and either later sold on the market or used to demonstrate compliance in 2010 and beyond at the facility that generated the excess allowances. In either case, there will be earlier health and environmental benefits because reductions are achieved sooner than they otherwise would be. These benefits extend to Hg emissions because, as explained above, we expect companies to meet the Hg cap by way of the controls they install for SO_2 and NO_X. Consequently, the incentive to achieve early reductions for SO_2 effectively assures early reductions for Hg.

Several additional technical and policy considerations strongly favor a cap-and-trade system. The objective of Hg control, as we understand it today, is not advanced as effectively under the prescriptive traditional MACT approach under section 112(d) for the regulation of HAP. The MACT approach calls for two phases of regulation: the first based on the concept of "maximum achievable control technology"; the second, to occur 8 years later, based on a "residual health-risk determination." The second phase itself involves a complex, two-step framework: one step to determine a "safe" or "acceptable risk" level, considering only public health factors, and the second to set an emission standard that provides an "ample margin of safety" to protect public health, considering relevant factors in addition to health, such as costs, economic impacts, technical feasibility, uncertainties and other factors.

First, a cap-and-trade approach sets a specific limit or cap on allowable emissions. Under a traditional section 112(d) MACT approach, standards are based on rates of emissions per unit of input or of production, for example, pounds per million Btu. Variations in production or differences in input mix will result in fluctuations in Hg emissions. Thus, with shifts in coal use and with growth in the economy, Hg emissions would likely substantially exceed the overall emission level achieved when the MACT limits are initially met.

Second, a trading approach is better suited to stimulating development and adoption of new technologies. A cap-and-trade system provides a market incentive for the development and use of cost-effective technology to reduce Hg emissions. A MACT approach provides no such market incentive, so plants do not have an incentive to reduce emissions below the required level. Additionally, the ability to bank unused allowances for future use leads to early reductions of Hg emissions. A trading approach is forward-looking in its assessment of technology, in that it provides a continuous incentive for firms to innovate and develop more cost-effective technologies to reduce Hg emissions.

The traditional section 112(d) MACT approach is designed to promote the use of proven control technologies by requiring all sources in a category to achieve the degree of emission control already accomplished by the average of the best 12 percent of sources in the category. However, such a MACT approach will not stimulate innovation in Hg control technology as well as a cap-and-trade approach because it does not reward reductions beyond the required levels.

Indeed, a traditional 112(d) MACT approach even could inhibit innovation. Section 112(d) does provide legal authority to go "beyond-the-floor" to require control strategies more stringent than the MACT floor, but the science, engineering and economics of Hg control have not progressed enough to support the technical determination that would be needed to support a section 112(d) standard that goes beyond the MACT floor. Once MACT-level controls are installed, there is little incentive for firms to develop even more effective technologies. In addition, the MACT deadline is so tight (2007 with only 1 year of possible extension) that affected firms would be unlikely to risk both capital and non-compliance in order to use more innovative approaches to Hg control.

Moreover, a trading approach could spur the development of cost-effective break-through technologies to control national and local Hg emissions. Such innovations would allow the U.S. to play a leadership role in the reduction of global Hg emissions as well. This is a crucial advantage of a trading approach to ultimately help remedy the problems posed by Hg emissions.

Third, from a capital planning perspective, a trading approach permits utilities to make a much more rational investment in emissions control than a traditional MACT approach. We now understand that utility investments in reducing criteria air pollutants (particulate matter, sulfur dioxide and oxides of nitrogen) provide a "co-benefit" for Hg control because some forms of Hg (especially those that are deposited nearest plants) are controlled by the same technologies used to control criteria pollutants. The exact size of this co-benefit is not known. In any event, given the likelihood of co-benefits, it makes good economic sense for utilities to coordinate control of criteria air pollutants—especially those needed to achieve the new air quality standards for fine particulate matter and ozone—with their capital investments aimed at reducing Hg emissions. The statutory deadlines for a Hg MACT rule do not permit this rational sequence of investments.

Thus, the Agency has carefully considered sections 112(d), 111, and 112(n) to determine which is more appropriate for application to Hg emissions from coal-fired Utility Units. The scientific, engineering, economic, and environmental considerations all weigh heavily in favor of a trading-based approach.

B. Is It Appropriate and Necessary To Regulate Coal- and Oil-Fired Utility Units Under Section 112 Based Solely on Emissions of Non-Hg and Non-Ni HAP?

In light of our revised interpretation of the scope of existing authority under the CAA, we have re-examined the results of the Utility RTC, focusing on the non-Hg and non-Ni HAP emissions from coal- and oil-fired Utility Units. The Study indicates that there are no non-Hg or non-Ni HAP emissions from Utility Units that warrant regulation.

We do recognize that in December 2000, we stated that arsenic and a few other metals, such as chromium, Ni and cadmium, were of potential concern for carcinogenic effects (65 FR 79827). We continue to believe, as stated above, that the record supports a distinction between the treatment of Ni emissions from oil-fired Utility Units and the emissions of other non-Hg metallic HAP. Such a distinction is warranted based on the relative magnitude of Ni that is emitted from oil-fired utility units on an annual basis and the scope and number of adverse health effects associated with such emissions. Thus, although we recognize that uncertainties do exist with regard to the data and information we have obtained to date for non-Hg metallic HAP, including Ni, we believe that the nature of the uncertainties associated with the non-Hg, non-Ni metallic HAP are so great that regulation of such pollutants is not appropriate at this time since those pollutants do not pose a hazard to public health that warrants regulation. The EPA does intend, however, to continue to study these pollutants in the future. The EPA also intends to continue to study dioxins, HCl, and HF in the future, but, at this time, the Study and the information EPA has obtained since the Study reveal no public health hazards reasonably anticipated to occur as a result of these HAP emissions from Utility Units such that they warrant regulation.[10]

Therefore, we believe that emissions of non-Hg and non-Ni HAP emissions from coal- and oil-fired Utility Units do not warrant regulation. We recognize that we based our appropriateness finding in December 2000, in part, on the existence of available control options that would reduce HAP emissions, including Hg, from Utility Units. *See* 65 FR 79830. The focus on available technologies was, however, a subsidiary rationale and one that was included only after we had determined that emissions of particular HAP from coal- and oil-fired Utility Units posed significant hazards to public health and the environment and that those hazards could only be addressed under CAA section 112. *See* 65 FR 79830.

As discussed above, we believe that any health effects resulting from Hg and Ni emissions from Utility Units can and will be addressed adequately pursuant to CAA section 111. Thus, while control strategies may exist to control the remaining HAP emitted from coal- and oil-fired Utility Units (*i.e.*, HAP other than Hg and Ni), we do not believe that it is appropriate to regulate such HAP under section 112 where we have not determined that emissions of such HAP from Utility Units pose health hazards that warrant regulation. This conclusion is consistent with CAA section 112(n)(1)(A), in which Congress called for EPA to focus on the health effects of

[10] As noted above, after the December 2000 finding, EPA conducted additional modeling that confirmed the Utility RTC's conclusion that acid gas HAP, such as HCl, HF, and Cl, pose no hazards to public health that warrant regulation. Furthermore, since December 2000, EPA has not obtained any new information that would cause it to modify its conclusion concerning the lack of health effects that warrant regulation associated with HAP other than Hg and Ni.

HAP from Utility Units following imposition of the other requirements of the CAA.

Moreover, even if in the future EPA finds that HAP emissions from Utility Units other than Hg and Ni emissions warrant regulation, EPA believes that CAA section 111 could be used to adequately address those hazards. Thus, EPA proposes to find that it is not only inappropriate to regulate coal- and oil-fired Utility Units under section 112 for HAP emissions other than Hg and Ni, but that it is not necessary to do so.

C. What Effect Does Today's Proposal Have on the December 2000 Decision To List Coal- and Oil-Fired Utility Units Under Section 112(c)?

In CAA section 112, Congress established a framework by which source categories could be listed, and once listed, emission standards developed for the listed source categories. The criteria and basis for listing a source category under section 112 differ depending on the sources at issue. (*See* generally CAA section 112(c) (discussing major and area sources).) In particular, for Utility Units, it only would be possible for EPA to list Utility Units under section 112(c) if it first made the section 112(n)(1)(A) finding that it was both appropriate and necessary to regulate such units under section 112, after EPA reviewed the results of its section 112(n)(1)(A) study concerning health effects and alternative control strategies.

In its December 2000 notice EPA took this additional step and after finding it was appropriate and necessary to regulate Utility Units under section 112, went on to list coal- and oil-fired Utility Units under section 112(c)(65 FR 79831).

As explained above, EPA has conducted a thorough re-analysis of the provisions of the CAA and determined that CAA section 111 is a viable statutory mechanism that would adequately address Hg and Ni emissions from coal- and oil-fired Utility Units. Therefore, EPA believes that the premise underlying its December 2000 "necessary" finding, that no other authority exists under the CAA to adequately address the public health hazards associated with Hg and Ni emissions, lacks foundation. The EPA also believes that it is not appropriate to regulate HAP other than Hg and Ni under section 112 because the Utility RTC reveals that there are no health hazards that warrant regulation associated with such HAP. Moreover, even if in the future EPA finds that there are HAP emissions (other than Hg and Ni) from Utility Units that pose hazards to public health and warrant regulation, EPA believes that CAA section 111 would adequately address those hazards and, therefore, that regulation of such units under section 112 would not be necessary. For all of these reasons, EPA now believes that its initial decision to list coal- and oil-fired Utility Units under section 112(c) in December 2000 was without proper foundation. The EPA, therefore, proposes to modify the section 112(c) list to delete coal- and oil-fired Utility Units as a source category. In light of EPA's interpretation and proposed use of its existing authority under the CAA and, in particular, CAA section 111, we propose to conclude that the statutory listing criteria were not met in December 2000.

The EPAs proposed action here is wholly consistent with its historical interpretation of CAA section 112(c)(9), which is that the de-listing criteria in section 112(c)(9) apply only where the original listing of a source category was consistent with the statutory listing criteria. The failure to fully recognize the scope of existing statutory authority in December 2000, is analogous to those situations where EPA has listed a source category under section 112(c)(1), and later determined that it lacked a factual predicate for such listing and, therefore, delisted the source category without following the criteria of section 112(c)(9). The EPA has done this on several occasions. For example, in 1992, EPA listed asphalt concrete manufacturers as a major source category [11] under section 112(c)(1), and then in 2002, delisted that category without following the statutory criteria in section 112(c)(9). The EPA did so because it determined that the initial criteria for listing had not been met since the sources in the asphalt concrete manufacturing category did not emit or have the potential to emit sufficient tons of hazardous air pollutants annually to satisfy the statutory definition of "major source." *See* 67 FR 6521, 6522 (February 12, 2002); see also 63 FR 7155, 7157 (February 12, 1998); 61 FR 28197, 28200 (June 4, 1996).

[11] Under the statute, a "major source" is any stationary source or group of stationary sources at a single location and under common control that emits or has the potential to emit 10 tons per year or more of any HAP or 25 tons per year or more of any combination of HAP.

IV. Proposed Standards of Performance for Mercury and Nickel From New Stationary Sources and Emission Guidelines for Control of Mercury and Nickel From Existing Sources: Electric Utility Steam Generating Units

A. Background Information

1. What Is the Statutory Authority for The Proposed Section 111 Rulemaking?

Section 111(b) of the CAA requires EPA to promulgate standards of performance for emissions of air pollutants from new stationary sources. These standards are typically referred to as NSPS. Section 111(d) requires the EPA to prescribe regulations that establish a procedure by which each State shall submit plans which establish standards of performance for existing sources for air pollutants for which air quality criteria have not been set but for which NSPS have been established.

2. What Criteria Are Used in the Development of NSPS?

Section 111(a)(1) of the CAA requires that standards of performance reflect the

> * * * degree of emission limitation achievable through application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.

The reader is referred to our interpretation of standard of performance set forth above.

B. Proposed New Standards and Guidelines

1. What Source Category Is Affected by the Proposed Rulemaking?

The subpart Da NSPS apply to Utility Units capable of firing more than 73 megawatts (MW) (250 million Btu/hour) heat input of fossil fuel. The current NSPS also apply to industrial cogeneration facilities that sell more than 25 MW of electrical output and more than one-third of their potential output capacity to any utility power distribution system.

2. What Pollutants Are Covered by the Proposed Rulemaking?

The proposed rule would add Hg and Ni to the list of pollutants covered under subpart Da by establishing emission limits for new sources and guidelines for existing sources. New sources (and existing subpart Da facilities), however, remain subject to the applicable existing subpart Da emission limits for NO_X, SO_2, and PM. See 40 CFR part 60, subpart Da, Standards of Performance for Electric

Utility Steam Generating Units for which Construction is Commenced after September 18, 1978.

3. What Are the Affected Sources?

Only those coal- and oil-fired Utility Units for which construction, modification, or reconstruction is commenced after January 30, 2004 would be affected by the proposed rule. Coal- and oil-fired Utility Units existing at the time of this proposal would be affected facilities for purposes of the proposed section 111(d) guidelines described in this notice.

4. What Emission Limits Must I Meet?

The following standards of performance for Hg are being proposed in today's notice for new coal-fired subpart Da units:

Bituminous units: 0.00075 nanograms per joule (ng/J) (0.0060 lb/gigawatt-hour (GWh));
Subbituminous units: 0.0025 ng/J (0.020 lb/GWh);
Lignite units: 0.0078 ng/J (0.062 lb/GWh);
Waste coal units: 0.00087 ng/J (0.0011 lb/GWh);
IGCC units: 0.0025 ng/J (0.020 lb/GWh).

The following standard of performance for Ni is being proposed for new oil-fired subpart Da units:

Ni: 0.010 (ng/J) (0.0008 lb/MWh).

All of these standards are based on gross energy output.

Compliance with the proposed standard of performance for Hg would be on a 12-month rolling average basis, as explained in section B.5 below. This compliance period is appropriate given the nature of the health hazard presented by Hg (*see* section B.5 below). Compliance with the proposed standard of performance for Ni would be on a continuous basis.

5. What Are the Testing and Initial Compliance Requirements?

New or reconstructed units must be in compliance with the applicable rule requirements upon initial startup or by the effective date of the final rule, whichever is later. The effective date is the date on which the final rule is published in the **Federal Register**.

Prior to the compliance date, the owner/operator would be required to prepare a unit-specific monitoring plan and submit the plan to the Administrator for approval. The proposed rule would require that the plan address certain aspects with regard to the monitoring system; installation, performance and equipment specifications; performance evaluations; operation and maintenance procedures; quality assurance techniques; and recordkeeping and reporting procedures. Beginning on the compliance date, the owner/operator would be required to comply with the plan requirements for each monitoring system.

Mercury emission limits. Compliance with the proposed standard of performance for Hg would be determined based on a rolling 12-month average calculation. The Hg emissions are determined by continuously collecting Hg emission data from each affected unit by installing and operating a CEMS or an appropriate long-term method that can collect an uninterrupted, continuous sample of the Hg in the flue gases emitted from the unit. The proposed rule would allow the owner/operator to use any CEMS that meets requirements in Performance Specification 12A (PS–12A), "Specifications and Test Procedures for Total Vapor-phase Mercury Continuous Monitoring Systems in Stationary Sources." An owner/operator electing to use long-term Hg monitoring would be required to comply using the new EPA Method 324, "Determination of Vapor Phase Flue Gas Mercury Emissions from Stationary Sources Using Dry Sorbent Trap Sampling." Performance Specification 12A and Test Method 324 are proposed as part of this rulemaking.

For new cogeneration units, steam is also generated for process use. The energy content of this process steam must also be considered in determining compliance with the output-based standard. Therefore, the owner/operator of a new cogeneration unit would be required to calculate emission rates based on electrical output to the grid plus half the equivalent electrical output energy in the unit's process steam. The procedure for determining these Hg emission rates is included in section B.4 of the proposed rule.

The owner/operator of a new coal-fired unit that burns a blend of fuels would develop a unit-specific Hg emission limitation and the unit Hg emission rate for the portion of the compliance period that the unit burned the blend of fuels. The procedure for determining these emission limitations is outlined in section B.4 of the proposed rule.

Nickel emission limits. Compliance with the applicable proposed standard of performance for Ni would be determined by performance tests conducted according to the requirements in 40 CFR 60.8 and 40 CFR 60.11 of the NSPS General Provisions and the requirements in the proposed rule. The proposed rule would require EPA Method 29 in appendix A to 40 CFR part 60 to be used for the measurement of Ni emissions in the flue gas. With Method 29, Method 1 would be used to select the sampling port location and the number of traverse points; Method 2 would be used to measure the volumetric flow rate; Method 3 would be used for gas analysis; and Method 4 would be used to determine stack gas moisture. Method 19 would be used to convert the Method 29 Ni measurements to an emission rate expressed in units of pounds per trillion British thermal units (lb/TBtu) if complying with an input-based standard.

The proposed rule would require the owner/operator to establish limits for control device operating parameters based on the actual values measured during each performance test. The proposed rule specifies the parameters to be monitored for the types of emission control systems commonly used in the industry. The owner/operator would be required to submit a monitoring plan identifying the operating parameters to be monitored for any control device used that is not specified in the proposed rule.

An initial performance test to demonstrate compliance with each applicable Ni emission limit would be required no later than 180 days after initial startup or 180 days after publication of the final rule, whichever is later, for a new or reconstructed unit.

The owner/operator of a new cogeneration unit would have to account for the process steam portion of their emissions in the same manner for Ni emissions as they did for Hg emissions. The owner/operator of a cogeneration unit would be required to calculate the Ni emission rate based on electrical output to the grid plus half the equivalent electrical output energy in the unit's process steam. The procedure for determining these Ni emission rates are given in § 60.46a of the proposed rule.

6. What Are the Continuous Compliance Requirements?

To demonstrate continuous compliance with the applicable emission limits under the proposed rule, the owner/operator would be required to perform continuous Hg emission monitoring for coal-fired units and continuous monitoring of appropriate operating parameters for the ESP used to comply with the Ni limits for oil-fired units. In addition, an annual performance test will be required for demonstrating compliance with the proposed standard of performance for Ni for oil-fired units. The annual performance test would be conducted in the same manner as the initial compliance demonstration.

7. What Are the Notification, Recordkeeping, and Reporting Requirements?

The proposed rule would require the owner/operator to keep records and file reports consistent with the notification, recordkeeping, and reporting requirements of the General Provisions of 40 CFR part 60, subpart A. Records required under the proposed rule would be kept for 5 years, with the 2 most recent years being on the facility premises. These records would include copies of all Hg emission monitoring data, coal usage, MWh generated, and heating value data required for compliance calculations; reports that have to be submitted to the responsible authority; control equipment inspection records; and monitoring data from control devices demonstrating that emission limitations are being maintained.

Two basic types of reports would be required: initial notifications and periodic reports. The owner/operator would be required to submit notifications described in the General Provisions (40 CFR part 60, subpart A), which include initial notification of applicability, notifications of performance tests, and notification of compliance status. For oil-fired units, if you at any time during the reporting period comply with an applicable emissions limit by switching fuel (in other than emergency situations), the proposed rule would also require that you notify EPA in writing at least 30 days prior to using a fuel other than distillate oil. In emergency situations, such notification must be within 30 days. As required by the General Provisions, the owner/operator would be required to submit a report of performance test results; develop and implement a written startup, shutdown, and malfunction plan and report semi-annually any events in which the plan was not followed; and submit semi-annual excess emissions reports of any deviations when any monitored parameters fell outside the range of values established during the performance test.

C. Rationale for the Proposed Subpart Da Standards

1. What Is the Rationale for the Proposed Subpart Da Hg and Ni Standards?

In December 2000, EPA announced a finding that regulation of Hg emissions from coal-fired Utility Units and Ni emissions from oil-fired Utility Units under CAA section 112 was appropriate and necessary. As explained above, we are proposing today to revise that finding. We continue to believe, however, that the HAP of greatest concern from coal-fired units is Hg, with Ni being the HAP of greatest concern from oil-fired units. In December 2000, based on the record before the Agency, EPA estimated that coal-fired Utility Units in the U.S. emitted approximately 48 tons of Hg into the atmosphere in 1999, and that methylmercury, the end product of Hg deposited to water bodies, is a significant health hazard, particularly to sensitive subpopulations. The EPA also found that Hg emissions could in some cases be reduced through application of control technology. Finally, the record supporting the December 2000 action reveals that oil-fired Utility Units emitted approximately 322 tons of Ni in 1994.

Today's action proposes standards under the regulatory authority of section 111(b), which will regulate Hg (from coal-fired units) and Ni (from oil-fired units) emissions from new units on which construction is commenced after today's date, and emissions guidelines under the authority of section 111(d), which will regulate Hg emissions from existing coal-fired Utility Units and Ni emissions from existing oil-fired Utility Units.

The source of Hg and Ni emissions from these units is the same at both new and existing steam generating units; therefore, in general, the control of these emissions would be the same as well. Throughout this preamble, where clear distinctions arise, the rationales for the EPA actions affecting new and existing units are discussed separately. Otherwise, the discussion applies to the proposed standards and emission guidelines.

2. What Is the Performance of Control Technology on Hg?

Currently, there are no commercially available control technologies specifically designed for reducing Hg emissions. However, available data indicate that controls installed for reducing emissions of PM, SO_2, and NO_X are also effective in some cases in reducing Hg emissions from coal-fired Utility Units. The degree of removal, however, depends (in part) on the rank of coal being burned.

The American Society for Testing and Materials (ASTM) classifies coals by rank, a term which relates to the carbon content of the coal and other related parameters such as volatile-matter content, heating value, and agglomerating properties. The coal-fired electric utility industry combusts the following coal ranks, presented in decreasing order: anthracite, bituminous, subbituminous, and lignite. The HHV of coal is measured as the gross calorific value, reported in British thermal units per pound (Btu/lb). The heating value of coal increases with increasing coal rank. The youngest, or lowest rank, coals are termed lignite. Lignites have the lowest heating value of the coals typically used in power plants. Their moisture content can be as high as 30 percent, but their volatile content is also high; consequently, they ignite easily. Next in rank are subbituminous coals, which also have a relatively high moisture content, typically ranging from 15 to 30 percent. Subbituminous coals also are high in volatile matter content and ignite easily. Their heating value is generally in between that of the lignites and the bituminous coals. Bituminous coals are next in rank, with higher heating values and lower moisture and volatile content than the subbituminous and lignite coals. Anthracites are the highest rank coals. Because of the difficulty in obtaining and igniting anthracite, only a single electric utility boiler in the U.S. burned anthracite as its only fuel in 1999. Because bituminous coal is the most similar coal to anthracite coal based on coal physical characteristics (ash content, sulfur content, HHV), anthracite coal is considered to be equivalent to bituminous coal for the purposes of the proposed rule and, thus, the anthracite-fired unit is considered a bituminous-fired unit for the purposes of the proposed rule.

Although there is overlap in some of the ASTM classification properties, the ASTM method of classifying coals by rank generally is successful in identifying some common core characteristics that have implications for power plant design and operation.

Coal refuse (*i.e.*, anthracite coal refuse (culm), bituminous coal refuse (gob), and subbituminous coal refuse) is also combusted in utility units. Coal refuse refers to the waste products of coal mining, physical coal cleaning, and coal preparation operations (*e.g.* culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material. Previously considered unusable by the industry because of the high ash content and relatively low heat content, it now may be utilized as a supplemental fuel in limited amounts in some units or as the primary fuel in a fluidized bed combustor (FBC). Because of the inherent inability to utilize coal refuse as the primary fuel in anything other than an FBC, it is considered to be a separate coal rank for purposes of the proposed rule.

The rank of coal to be burned has an enormous impact on overall plant design. The goal of the plant designer is to arrange boiler components (furnace, superheater, reheater, boiler bank, economizer, and air heater) to provide the rated steam flow, maximize thermal efficiency, and minimize cost. Engineering calculations are used to determine the optimum positioning and sizing of these components, which cool the flue gas and generate the superheated steam. The accuracy of the parameters specified by the owner/operators is critical to designing and building an optimal plant. The rank of coal to be burned greatly impacts the entire design process. The rank of coal burned also has significant impact on the design and operation of the emission control equipment (*e.g.*, ash resistivity impact on ESP performance).

For the above reasons, one of the most important factors in modern electric utility boiler design involves the differences in the ranks and range of coals to be fired and their impact on the details and overall arrangement of boiler components. Coal rank is so important that plant designers and manufacturers expect to be provided with a complete list of all coal ranks presently available or planned for future use, along with their complete chemical and ash analyses, so that the engineers can properly design and specify plant equipment. The various coal characteristics (*e.g.*, how hard the coal is to pulverize; how high its ash content; the chemical content of the ash; how the ash "slags" (fused deposits or resolidified molten material that forms primarily on furnace walls or other surfaces exposed predominantly to radiant heat or high temperature); how big the boiler has to be to adequately utilize the heat content; etc.), therefore, impact on boiler design from the pulverizer through the boiler to the final steam tubes. For a boiler to operate efficiently, it is critical to recognize the differences in coals and make the necessary modifications in boiler components during design to provide optimum conditions for efficient combustion.

Coal-fired units are designed and constructed with different process configurations partially because of the constraints, including the properties of the fuel to be used, placed on the initial design of the unit. Accordingly, these site-specific constraints dictate the process equipment selected, the component order, the materials of construction, and the operating conditions.

Approximately 23 percent of coal-fired Utility Units either (1) co-fire two or more ranks of coal (with or without other fuels) in the same boiler, or (2) fire two or more ranks of coal (with or without other fuels) in the same boiler at different times (1999 EPA ICR). This coal "blending" is done generally for one of three reasons: (1) To achieve SO_2 emission compliance with title IV provisions of the CAA, (2) to prevent excessive slagging by improving the heat content of a lower grade coal, or (3) for economic reasons (*i.e.*, coal rank price and availability).

These blended coals, although of different rank, do have similar properties. That is, because of the overlap in various characteristics in the ASTM definitions of coal rank, certain bituminous and subbituminous coals (for example) exhibit similar handling and combustion properties. Plant designers and operators have learned to accommodate these blends in certain circumstances without significant impact on plant operation or control.

The flue gases resulting from the combustion of these different coal ranks can exhibit different Hg emissions characteristics. These Hg emissions characteristics consist of varying percentages of the three relevant forms (or species) of Hg (particulate-bound, oxidized (ionic), and elemental) that makeup the total Hg in the flue gas.

Available source test data shows that combustion of bituminous coal results in Hg emissions that are composed of relatively more Hg^{++} compared to the other coal ranks. Combustion of bituminous coal produces the most particulate-bound Hg of any of the three major coal ranks combusted. Combustion of subbituminous coal results in emissions that are composed of relatively more elemental Hg (compared to bituminous coal), with little particulate-bound Hg (less than half that of bituminous coal emissions). Combustion of lignite coal also results in emissions that are composed of relatively more elemental Hg (compared to bituminous coal) with little particulate-bound Hg (also less than half that of bituminous coal emissions). Available data indicate that emissions from the combustion of coal refuse tends to result almost entirely in particulate-bound Hg (greater than 99 percent for both units tested in the 1999 EPA ICR). With few exceptions, particulate-bound Hg can be removed with PM controls, Hg^{++} can be removed with wet SO_2 controls (FGD scrubbers), but elemental Hg usually shows little to no removal with any existing conventional type of APCD used on utility boilers. However, new technologies such as activated carbon adsorption show promise in removing elemental Hg.

There are five basic types of coal combustion processes used in the coal-fired electric utility industry. These are conventional-fired boilers, stoker-fired boilers, cyclone-fired boilers, integrated gasification combined cycle (IGCC) units, and fluidized bed combustors (FBC).

Conventional boilers, also known as pulverized coal (PC) boilers, have a number of firing configurations based on their burner placement. The basic characteristic that all conventional boilers have in common is that they inject PC and primary air through a burner where ignition of the PC occurs, which in turn creates an individual flame. Conventional boilers fire through many such burners mounted in the furnace walls.

In stoker-fired boilers, fuel is deposited on a moving or stationary grate or spread mechanically or pneumatically from points usually 10 to 20 feet above the grate. The process utilizes both the combustion of fine coal powder in air and the combustion of larger particles that fall and burn in the fuel bed on the grate.

Cyclone-fired boilers use several water-cooled horizontal burners that produce high-temperature flames that circulate in a cyclonic pattern. The burner design and placement cause the coal ash to become a molten slag that is collected below the furnace.

Fluidized bed combustors combust coal, in a bed of inert material (*e.g.*, sand, silica, alumina, or ash) and/or a sorbent such as limestone, that is suspended through the action of primary combustion air distributed below the combustor floor. "Fluidized" refers to the state of the bed of material (coal and inert material (or sorbent)) as gas passes through the bed. As the gas flow rate is increased, the force on the fuel particles becomes just sufficient to cause buoyancy. The gas cushion between the solids allows the particles to move freely, giving the bed a liquid-like (or fluidized) characteristic.

Integrated-coal gasification combined cycle units are specialized units in which coal is first converted into synthetic coal gas. In this conversion process, the carbon in the coal reacts with water to produce hydrogen gas and CO. The synthetic coal gas is then combusted in a combustion turbine which drives an electric generator. Hot gases from the combustion turbine then pass through a waste heat boiler to produce steam. This steam is fed to a steam turbine connected to a second electric generator.

Available information indicates that Hg emissions from coal-fired Utility Units are minimized in some cases through the use of PM controls coupled with an FGD system. For bituminous-fired units, use of a selective catalytic reduction (SCR) or selective noncatalytic reduction (SNCR) system may further enhance Hg removal. This does not appear to be the case for subbituminous- and lignite-fired units. The EPA believes the best potential way of reducing Hg emissions from IGCC units is to remove Hg from the syngas before combustion. An existing industrial IGCC unit has demonstrated a process, using sulfur-impregnated AC carbon beds, that has proven to yield 90 to 95 percent Hg removal from the coal syngas. This technology could potentially be adapted to the electric utility IGCC units. The EPA believes this to be a viable option for IGCC units.

3. What Is the Performance of Control Technology on Ni?

The EPA analyzed the data available on the fuel, process, emission profiles, and APCD for oil-fired units at existing affected sources. An oil-fired electric utility boiler combusts fuel oil exclusively, or combusts fuel oil at certain times of the year and natural gas at other times (not simultaneously). The choice of when to combust oil exclusively or to alternate between oil and natural gas at a single boiler is usually based on economics or fuel availability (including seasonal availability). The ASTM classifies oils by "grade," a term which relates to the amount of refinement that the oil undergoes. The level of refinement directly affects the Ni and carbon content of the oil and other related parameters such as sulfur content, heating value, and specific gravity. The most refined fuel oil used by the oil-fired electric utility industry is known as No. 2 fuel oil (also known as distillate oil or medium domestic fuel oil). The least refined fuel oil used by the oil-fired electric utility industry is known as No. 6 fuel oil (also known as residual oil or Bunker C oil). By comparison, No. 2 fuel oil is lower in Ni, sulfur, ash content, and heating value but higher in carbon content than No. 6 fuel oil. Only a handful of boilers (8 of 218) fire No. 2 distillate fuel oil exclusively. (2001 EIA data) However, 28 out of 218 boilers fire No. 2 distillate fuel oil and No. 6 (residual) fuel oil in the same boiler (either simultaneously or at separate times).

The proposed standard of performance for Ni from new oil-fired units was determined by analyzing the emissions data available. The data were obtained from the Utility RTC which provided information indicating that Ni was the pollutant of concern due to its high level of emissions from oil-fired units and the potential health effects resulting from exposure to it. The EPA examined available test data and found that ESP-equipped units can effectively reduce Ni. The proposed standard of performance for Ni is based on the level of control demonstrated by the top performing existing units with regard to removal of Ni. The test data were converted to an output-based limit using an efficiency factor.

The EPA is sensitive to the fact that some sources burn fuels containing very little Ni. Therefore, EPA solicits comment on a Ni-in-oil limit that would be equivalent to the proposed stack value of 0.0005 lb/MWh gross. With a limit on the amount of Ni in the oil, a new source could choose to comply with an alternate oil-content-based Ni emission limitation instead of the stack Ni emission limit to meet the proposed rule. Such an alternate Ni-in-oil limit could be useful where Ni constituent levels are low in the fuel.

Dual-Fired (Oil/Natural Gas) Units. The EPA is aware that an oil-fired unit may fire oil at certain times of the year and natural gas at other times. The choice of when to fire oil or natural gas is usually based on the economics or availability of fuel (*i.e.*, seasonal considerations). The EPA considers a unit to be an oil-fired unit if (1) it is equipped to fire oil and/or natural gas, and (2) it fires oil in amounts greater than or equal to 2 percent of its annual fuel consumption. This 2 percent value is intended to represent that amount of oil that a true natural gas-fired unit might use strictly for start-up purposes on an annual basis. The EPA solicits comment on whether this two percent breakpoint is a reasonable basis for allowing those units that use oil only for startup purposes to be exempted from regulation under the proposed rule.

4. What Is the Regulatory Approach?

Subpart Da Hg emission standards. In selecting a regulatory approach for formulating emission standards to limit Hg emissions from new coal-fired steam generating units, the performance of the Hg control technologies discussed above were considered. The technical basis (*i.e.*, BDT) selected for establishing Hg emission limits for new sources is the use of effective PM controls and wet or dry FGD systems on subbituminous-, lignite-, and waste coal-fired units and effective PM controls, wet or dry FGD systems, and SCR or SNCR on bituminous-fired units, and activated carbon beds for IGCC units.

Section 111(b)(2) of the CAA allows the Administrator to "* * * distinguish among classes, types, and sizes within categories of new sources * * *" in establishing standards when differences between given types of sources within a category lead to corresponding differences in the nature of emissions and the technical feasibility of applying emission control techniques. After examining a number of possible subcategorization options, EPA identified two basic ways to subcategorize coal-fired Utility Units, by coal rank or by process type.

Subcategorization by coal rank. Subcategorization by individual coal rank addresses the differences in the characteristics of the Hg emissions (*i.e.*, speciation of Hg) and the resulting ability to control Hg as well as accommodating the various design and control constraints resulting from the various coal ranks.

Subcategorization by process type. Another option is to subcategorize by process type. Different process types could create potential emissions differences which lead to corresponding differences in the nature of emissions and the technical feasibility of applying emission control techniques. Although conventional-, stoker-, and cyclone-fired boilers use different firing techniques, the Hg emissions characteristics of these boilers are similar (given that common ranks of coal are fired) and, therefore, the units can be grouped together. Although these units fire a variety of coal ranks they have only combusted coal refuse in lesser amounts as a secondary fuel source.

Based on their unique firing designs, FBC units employ a fundamentally different process for combusting coal from that employed by conventional-, stoker-, or cyclone-fired boilers. Fluidized-bed combustors are capable of combusting many coal ranks including coal refuse. For these reasons, FBC units can be considered a distinct type of boiler. However, the Hg emissions test data results for FBC units were not substantially different from those at similarly-fueled conventionally-fired units with similar emission levels, either in mass of emissions or in emissions characteristics.

Integrated gasification combined cycle units combust a synthetic coal gas. No coal is directly combusted in the unit during operation (although a coal-derived fuel is fired), and, thus, IGCC units are a distinct class or type of boiler for the proposed rule.

Based on the above discussion, the EPA is proposing to use five subcategories for establishing Hg limits based on a combination of coal rank and process type in this rule (bituminous coal, subbituminous coal, lignite coal, coal refuse, and IGCC).

The EPA's review of the available emission data shows that Hg emissions from new coal-fired units can be reduced to the following:

Bituminous units: 0.61 lb/TBtu heat input;
Subbituminous units: 2.0 lb/TBtu heat input;
Lignite units: 6.3 lb/TBtu heat input;
Waste coal units: 0.11 lb/TBtu heat input;
IGCC units: 2.0 lb/TBtu heat input.

Mercury emissions from new oil- and gas-fired units are not covered by the proposed rule.

Subpart Da Ni emission standards. In selecting a regulatory approach for formulating emission standards to limit Ni emissions from new oil-fired steam generating units, the performance on Ni of the PM control technologies discussed above were considered. The technical basis (*i.e.*, BDT) selected for establishing Ni emission limits for new sources is the use of ESP units or oils low in Ni content.

The EPA's review of the available emission data shows that Ni emissions from new oil-fired units can be reduced to 84 lb/TBtu heat input.

5. What Are the Subpart Da Hg and Ni Emission Standards?

Based on available performance data analyses from the 1999 ICR for coal-fired Utility Units, the Administrator has concluded that the application of fabric filters or ESP units along with wet or dry FGD is considered to be the most effective Hg control technology for units firing subbituminous, lignite, or waste coals; and that the application of fabric filters or ESP units, wet or dry FGD systems, and SCR is considered to be the most effective Hg control technology for units firing bituminous coals. For IGCC units (regardless of coal rank fired), the Administrator has concluded that use of a carbon bed is considered to be the most effective Hg control technology. These controls represent the best system of emissions reductions (taking into consideration the cost of achieving such emissions reductions, any non-air quality health and environmental impact, and energy requirements).

Based on available performance data and cost analyses, the Administrator has concluded that the application of ESP units or oils containing a low Ni content is considered to be the most effective Ni control technology for oil-fired units. These controls represent the best system of emissions reductions (taking into consideration the cost of achieving such emissions reductions, any non-air quality health and environmental impact, and energy requirements).

6. How Did EPA Select the Format for the Proposed Standards?

Based on the analyses and discussion presented earlier, EPA has selected an output-based format for the proposed new-source rule. The Administrator is proposing today Hg emission limits for new coal-fired Utility Units as follows:

Bituminous units: 0.0060 GWh gross;
Subbituminous units: 0.020 lb/GWh gross;
Lignite units: 0.062 lb/GWh gross;
Waste coal units: 0.0011 lb/GWh gross;
IGCC units: 0.020 lb/GWh gross.

Based on the available performance data, cost analysis, and the above calculation, the Administrator is proposing today Ni emission limits for new oil-fired Utility Units as follows: 0.0008 lb/MWh gross.

7. How Did EPA Determine Testing and Monitoring Requirements for the Proposed Standards?

The CAA requires EPA to develop regulations that ensure initial and continuous compliance. Testing and monitoring requirements allow EPA to determine whether an affected source is operating in compliance with an applicable emission limitation/standard. This section discusses how EPA selected the proposed testing and monitoring requirements used to determine compliance with the Hg and Ni emission limits that are specified in the proposed rule.

Mercury testing and monitoring requirements. The proposed rule would establish Hg emission limits for coal-fired units. The format selected for these Hg emission limits is a 12-month rolling average Hg emission level expressed in units of lb/TBtu or lb/MWh. Therefore, appropriate testing or monitoring requirements for determining the amount of Hg emitted from an affected unit throughout the compliance averaging period must be included in the rule.

The most direct means of demonstrating compliance with an emission limit is by the use of a CEMS that measures the pollutant of concern. The EPA considers other testing or monitoring options when acceptable CEMS are not available for the intended application or when the impacts of including such CEMS requirements in the proposed rule are considered by EPA to be unreasonable. In determining whether to require the use of other testing or monitoring options in lieu of CEMS, it is often necessary for EPA to balance more reasonable costs against the quality or accuracy of the actual emissions data collected.

There are several approaches to Hg monitoring that EPA has identified for possible use in this rule to determine compliance with the proposed Hg emission limits. One option is to use a CEMS that combines both automated sampling and analytical functions in a single system to provide continuous, real-time Hg emission data. Mercury CEMS are currently available from several manufacturers. These Hg CEMS are similar to most other types of instruments used for continuous monitoring of pollutants from combustion processes, in that the combustion gas sample is first extracted from the stack and then transferred to an analyzer for analysis. In general, the Hg CEMS now available can be distinguished by the Hg measurement detection principle used (*e.g.*, atomic adsorption, atomic fluorescence, x-ray fluorescence). Capital costs for a Hg CEMS are currently estimated to range from approximately $95,000 to $135,000, depending on the manufacturer and model selected. The annual costs to operate and maintain a Hg CEMS are estimated to range from $45,000 to $65,000, again depending on the manufacturer and model selected.

A second option is to use a long-term sampling method that collects a cumulative Hg sample by continuously passing a low-flow sample stream of the combustion process flue gas through a Hg trapping medium (*e.g.*, an activated carbon tube). This sampling tube is then periodically removed (*e.g.*, after a day or up to 1 month) and replaced with a tube filled with fresh trapping medium. The removed sampling tube is then sent to a laboratory where the trapping medium is analyzed for its Hg content. This method, like using a Hg CEMS, is capable of providing data on the Hg emissions from a combustion process on a continuous basis, but unlike a Hg CEMS, the data are not reported on a real-time basis. Using the long-term sampling method, the Hg collected in the sampling tube is integrated over a much longer sampling period (*i.e.*, 1 to 7 days for the AC tube versus less than 15 minutes for the CEMS). The capital cost for a gas metering system and Hg trapping medium is estimated to be approximately $18,000. The annual costs for periodic sampling tube replacement and for the laboratory Hg analysis range from approximately $65,000 to $125,000 depending upon quality assurance and quality control (QA/QC) requirements and frequency of sample tube replacement.

Finally, a third monitoring option is to use one of the manual stack test methods available for measuring Hg emissions from combustion processes on an intermittent basis. The existing voluntary consensus stack test method ASTM Method D6784–02 (commonly known as the Ontario-Hydro method) is currently the method of choice for measuring Hg species in the flue gas from Utility Units. Another method for measuring total (*i.e.*, not speciated) Hg is EPA Reference Method 29. This method involves a technician extracting a representative flue gas sample over a relatively short period of time (*e.g.*, a few hours) using a sampling train consisting of a nozzle and probe, a filter to collect particulate matter, and a liquid solution and/or reagent to capture gas-phase Hg. After sampling, the filter and sorption media are prepared and analyzed for Hg in a laboratory. These test methods could be applied to a Hg monitoring program at electric utility plants by performing a manual stack test using ASTM Method D6784–02 or EPA Reference Method 29 at some specified periodic interval throughout the compliance averaging period (*e.g.*, perform a stack test daily, weekly, biweekly, monthly). The cost to conduct a single ASTM Method D6784–02 typically ranges from $15,000 to $17,000 depending on site conditions. Annual costs will depend on the frequency with which the stack test is required to be performed during the compliance averaging period. For example, if the test is required once per week, the total annual cost would be as much as $780,000 (52 tests in a 12-month period at $15,000 per test).

The EPA evaluated each of the above Hg monitoring options with respect to its suitability for the measurement of the Hg emission data needed for determining compliance with the 12-month rolling average Hg emission limit. The EPA rejected from further consideration the third option, intermittent monitoring using manual stack test methods. Use of this monitoring approach would place significantly higher labor requirements and monitoring costs on facility owners/operators than the other two options in order to perform an adequate number of source tests throughout the compliance averaging period to demonstrate with reasonable confidence that the applicable Hg emission limit value was being achieved.

Both of the remaining two options would provide the necessary data to calculate the total Hg emissions from an affected source for each 12-month compliance averaging period. While the CEMS would provide these data on a real-time basis, EPA concluded that having real-time data is not mandatory for determining compliance with an emission limit based on a 12-month rolling average. Total Hg emissions from an affected source by month are needed to compute the rolling 12-month average Hg emission value. With regular scheduled replacement and timely analysis of sampling tubes, total monthly Hg emissions can readily be obtained using the long-term sampling method.

The EPA then compared the costs of applying the Hg CEMS and long-term monitoring options to Utility Units. While the CEMS have significantly higher capital costs, the automated analyses directly by the instrument eliminates the need and cost for separate analyses of the collected sampling tubes in a laboratory required by the long-term sampling method. Overall, EPA determined that the total costs of using either monitoring method to determine compliance would be similar for a given site. Selection of which monitoring method should be used at the site will depend on site-specific conditions and owner/operator preferences. Because both monitoring methods will collect the Hg emission data necessary to determine compliance with the proposed Hg emission limit and the costs of either option are reasonable, EPA decided to allow the owner/operator flexibility under the proposed rule to choose to use either Hg CEMS or long-term sampling monitoring as best suits their site conditions and preferences.

An owner/operator electing to use a CEMS to comply with the rule would be allowed to use any CEMS that meets the requirements in "Performance Specification 12A, Specifications and Test Procedures for Total Vapor-phase Mercury Continuous Monitoring Systems in Stationary Sources" (PS–12A). This performance specification is proposed as part of this rulemaking and we request comment on continuous monitoring of Hg emissions according to the requirements in the proposed performance specification.

Those owners/operators electing to use long-term Hg monitoring would be required to follow the requirements in Method 324, "Determination of Vapor Phase Flue Gas Mercury Emissions from Stationary Sources Using Dry Sorbent Trap Sampling" when it is promulgated. Method 324 is proposed as part of this rulemaking to be added to 40 CFR part 60, appendix A. We request comments on the requirements in proposed Method 324 for Hg measurement using long-term sampling.

Continuous compliance requirements are required under every NSPS so that EPA can determine whether an affected source remains in compliance with the applicable emission limitation/standard following the initial compliance determination. In the case of the proposed NSPS, the format for the Hg emission limit is a 12-month rolling average limit. The same monitoring requirements used to establish initial compliance of an affected electric utility unit with the applicable Hg emission limit at the end of the first 12-month period following the facility's compliance date serve to demonstrate continuous compliance with the Hg emission limit with the computation of each new 12-month rolling average value each month thereafter. Thus, no additional continuous compliance Hg monitoring requirements beyond those previously discussed are required for the proposed rule.

The EPA is concerned about monitoring costs for units with low Hg emissions rates, and does not desire to adopt a monitoring scheme where the costs are disproportionate to the costs of compliance with the MACT emissions limitations. For these units (*e.g.*, those emitting under 25 pounds per year) the EPA may consider reduced monitoring frequencies and lower cost monitoring requirements, since the need for accuracy is reduced for such units. For example, the EPA is concerned about the merits of requiring an expenditure of $100,000 per year to monitor releases when the costs of substantive compliance is far less. The Agency requests comments and related data upon which to establish an alternate reporting scheme.

Nickel testing and monitoring requirements. The proposed rule would establish Ni emission limits for oil-fired units. The EPA selected a different format for the Ni emission limits than is proposed for the Hg emission limits. The Ni emission limits are maximum allowable emission limits not to be exceeded, expressed in lb/TBtu or lb/MWh.

The EPA selected the proposed testing requirements to determine compliance with the Ni emission limits to be consistent with existing procedures used for the electric utility industry. Method 29 in appendix A to 40 CFR part 60 is an EPA reference test method that has been developed and validated for the measurement of Ni emissions from stationary sources. For sampling and analysis of the gas stream, the following EPA reference methods would be used with Method 29: Method 1 to select the sampling port location and the number of traverse points; Method

2 to measure the volumetric flow rate; Method 3 for gas analysis; and Method 4 to determine stack gas moisture. Method 19 specifies the procedure for collecting the necessary fuel data to be used with the Method 29 Ni measurements from the source test to compute the Ni emission rate expressed in units of lb/TBtu.

As an alternative under the proposed rule, an owner/operator of an existing oil-fired source could choose to comply with the applicable Ni emission limit expressed in lb/MWh.

To address the need for continuous compliance requirements for the proposed Ni emission limits, EPA considered the availability and feasibility of a number of Ni monitoring options ranging from direct monitoring of Ni emissions, to process parameter monitoring, to control device parameter monitoring. Monitors for continuously measuring Ni emissions have not been demonstrated in the U.S. for the purpose of determining compliance. Therefore, EPA did not consider further the use of any continuous monitoring for Ni for the proposed rule.

Another option used in other NSPS for demonstrating continuous compliance is to monitor appropriate process and/or control equipment operating parameters. These parameters are established during the initial, and any subsequent, stack test. Process parameters were not selected as indicators for Ni emissions from Utility Units because a direct correlation does not exist between combustion or electricity production parameters and Ni emission rates from a given unit.

Monitoring of PM control device operating parameters is used in other NSPS established for combustion processes and other source categories that include PM emission limits. The EPA decided to also use this continuous monitoring approach to demonstrate continuous compliance with the applicable Ni emission limits set forth in the proposed rule. The selected operating parameters for the PM control device used by oil-fired Utility Units (*e.g.*, ESP) are reliable indicators of control device performance. The EPA believes that reasonable assurance of compliance with the emission limits proposed for this NSPS can be achieved through appropriate monitoring and inspection of the operation of the APCD that have been demonstrated by an initial performance test to achieve the applicable Ni emission limits under the rule.

Compliance calculations. For cogeneration units, steam is also generated for process use. The energy content of this process steam must also be considered in determining compliance with the output-based standard. This consideration is accomplished by taking the net efficiency of a cogeneration unit into account. Under a Federal Energy Regulatory Commission (FERC) regulation, the efficiency of cogeneration units is determined from "* * * the useful power output plus one half the useful thermal output * * *," (18 CFR part 292, 205). To determine the process steam energy contribution to net plant output, a 50 percent credit of the process steam heat is necessary.

Therefore, owners/operators of cogeneration units subject to the proposed rule would need to monitor the portion of their net plant output that is process steam so that they can take the 50 percent credit of the energy portion of their process steam net output. For example, a cogeneration unit subject to the rule measures its net electrical output over a compliance period, as 30,000 MWh. During the same period the unit burns coal that provides 750 billion Btu input to its furnace/boiler, and emits 0.2 lb Hg. Using equivalents found in 40 CFR part 60 for electric utilities (*i.e.*, 250 million Btu/hr input to a boiler is equivalent to 73 MWe input to the boiler; 73 MWe input to the boiler is equivalent to 25 MWe output from the boiler; therefore, 250 million Btu input to the boiler is equivalent to 25 MWe output from the boiler) the 50 percent credit could be found as follows. The net output calculation would be 750 billion Btu × (25 MWe output/250 million Btu/hr input) = 75,000 MWh equivalent electrical output from the boiler over the compliance period. Of this amount, 30,000 MWh was produced as electricity sent to the grid, leaving 45,000 MWh as the energy converted to steam for process use. Half of this amount is 22,500 MWh. The unit's Hg CEM records a total of 0.2 lb Hg over the same compliance period. The adjusted Hg emission rate is then: 0.2 lb Hg/(30,000 MWh + 22,500 MWh) = 3.8×10^{-6} lb Hg/MWh. Cogeneration units would have to account for the process steam portion of their emissions in the same manner for PM emissions as well.

8. How Did EPA Determine the Compliance Times for the Proposed Standards?

New sources are required to be in compliance either upon start up or the effective date of this rule, whichever is later.

9. How Did EPA Determine the Required Records and Reports for the Proposed Standards?

Under section 114(a) of the CAA, EPA may require owners/operators of affected sources subject to a NSPS to maintain records as well as prepare and submit notifications and reports to the EPA. In addition, section 504(a) of the CAA mandates that sources required to obtain a title V permit submit a report setting forth the results of any required monitoring no less often than every 6 months. The general recordkeeping, notification, and reporting requirements for all NSPS are specified in 40 CFR 60.7 and 40 CFR 60.19 of the General Provisions, if incorporated into the proposed rule. The recordkeeping, notification, and reporting requirements for the proposed rule were selected to include all of the applicable records, notifications, and reports specified by the General Provisions requirements. Additional requirements were included in the proposed rule that are necessary to ensure that a given affected source is complying with the emission limits from the correct subcategory.

The proposed rule would also require that the owner/operator keep monthly records for each affected source listing the type of fuel burned, the total fuel usage, and the fuel heating value. Additional recordkeeping would be required for those owners/operators electing to comply with a fuel blending emission limit. The owner/operator would be required to maintain records of all compliance calculations and supporting information.

D. Rationale for the Proposed Hg Emission Guidelines

1. What Is the Authority for Cap-and-Trade Under Section 111(d)?

Section 111(d)(1) authorizes EPA to promulgate regulations that establish a State Implementation Plan-like (SIP-like) procedure under which each State submits to EPA a plan that, under subparagraph (A), "establishes standards of performance for any existing source" for certain air pollutants, and which, under subparagraph (B), "provides for the implementation and enforcement of such standards of performance." Paragraph (1) continues, "Regulations of the Administrator under this paragraph shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies." Section 111(a) defines, "(f)or purposes of * * * section (111)," the term "standard of performance" to mean

a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.

Taken together, these provisions authorize EPA to promulgate a "standard of performance" that States must, through a SIP-like system, apply to existing sources. A "standard of performance" is defined as a rule that limits emissions to the degree achievable through "the best system of emission reduction" that EPA "determines has been adequately demonstrated," considering costs and other factors.

A cap-and-trade program reduces the overall amount of emissions by requiring sources to hold allowances to cover their emissions on a one-for-one basis; by limiting overall allowances so that they cannot exceed specified levels (the "cap"); and by reducing the cap to less than the amount of emissions actually emitted, or allowed to be emitted, at the start of the program. In addition, the cap may be reduced further over time. Authorizing the allowances to be traded maximizes the cost-effectiveness of the emissions reductions in accordance with market forces. Sources have an incentive to endeavor to reduce their emissions below the number of allowances they receive; if they can do so cost-effectively, they may then sell their excess allowances on the open market. On the other hand, sources have an incentive to not put on controls that cost more than the allowances they may buy on the open market.

The term "standard of performance" is not explicitly defined to include or exclude an emissions cap and allowance trading program. In today's action, EPA proposes to interpret the term "standard of performance," as applied to existing sources, to include a cap-and-trade program. This interpretation is supported by a careful reading of the section 111(a) definition of the term, quoted above: A requirement for a cap-and-trade program (i) constitutes a "standard for emissions of air pollutants" (*i.e.*, a rule for air emissions), (ii) "which reflects the degree of emission limitation achievable" (*i.e.*, which requires an amount of emissions reductions that can be achieved), (iii) "through application of (a) * * * system of emission reduction" (*i.e.*, in this case, a cap-and-trade program that caps allowances at a level lower than current emissions).[12]

Nor do any other provisions of section 111(d) indicate that the term "standard of performance" may not be defined to include a cap-and-trade program. Section 111(d)(1)(B) refers to the "implementation and enforcement of such standards of performance," and section 111(d)(1) refers to the State "in applying a standard of performance to any particular source," but all of these references readily accommodate a cap-and-trade program.

Although section 111(a) defines "standard of performance" for purposes of section 111, section 302(l) defines the same term, "(w)hen used in this Act," to mean "a requirement of continuous emission reduction, including any requirement relating to the operation or maintenance of a source to assure continuous emission reduction." The term "continuous" is not defined in the CAA.

Even if the 302(l) definition applied to the term "standard of performance" as used in section 111(d)(1), EPA believes that a cap-and-trade program meets the definition. A cap-and-trade program with an overall cap set below current emissions is a "requirement of * * * emission reduction." Moreover, it is a requirement of "continuous" emissions reductions because all of a source's emissions must be covered by allowances sufficient to cover those emissions. That is, there is never a time when sources may emit without needing allowances to cover those emissions.[13]

We note that EPA has on one prior occasion authorized emissions trading under section 111(d). (The Emission Guidelines and Compliance Times for Large Municipal Waste Combustors that are Constructed on or Before September 20, 1994; 40 CFR part 60, subpart Cb.) This provision allows for a NO_X trading program implemented by individual States. Section 60.33b(C)(2) states,

A State plan may establish a program to allow owners or operators of municipal waste combustor plants to engage in trading of nitrogen oxides emission credits. A trading program must be approved by the Administrator before implementation.

Today's proposal is wholly consistent with this prior section 111(d) trading provision.

Having interpreted the term "standard of performance" to include a cap-and-trade program, EPA must next "determine" that such a system is "the best system of emissions reductions which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) * * * has been adequately demonstrated." Section 111(a)(1). The EPA proposes to determine that a cap-and-trade program has been adequately determined to be the best system for reducing Hg emissions from coal-fired Utility Units.

Since the passage of the 1990 Amendments to the CAA, EPA has had significant experience with the cap-and-trade program for utilities. The 1990 Amendments provided, in title IV, for the acid rain program, a national cap-and-trade program that covers SO_2 emissions from utilities. title IV requires sources to hold allowances for each ton of emissions, on a one-for-one basis. The EPA allocates the allowances for annual periods, in amounts initially determined by the statute, and that decrease further at a statutorily specified time. This program has resulted in an annual reduction in SO_2 emissions from utilities from 15.9 million tons in 1990 (the year the Amendments were enacted) to 10.2 million tons in 2002 (the most recent year for which data is available). Emissions in 2002 were 9 percent lower than 2000 levels and 41 percent lower than 1980, despite a significant increase in electrical generation. As discussed elsewhere, at full implementation after 2010, emissions will be limited to 8.95 million tons, a 50 percent reduction from 1980 levels. The Acid Rain program allowed sources to trade allowances, thereby maximizing overall cost-effectiveness.

In addition, in the 1998 NO_X SIP Call rulemaking, EPA promulgated a NO_X reduction requirement that affects 21 States and the District of Columbia ("Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone; Rule," 63 FR 57,356 (October 27, 1998)). All of the affected jurisdictions are implementing the requirements through a cap-and-trade program for NO_X emissions

[12] The legislative history of the term, "standard of performance," does not address an allowance/trading system, but does indicate that Congress intended that existing sources be accorded flexibility in meeting the standards. *See* "Clean Air Act Amendments of 1977," *Committee on Interstate and Foreign Commerce*, H.R. Rep. No. 95–294 at 195, *reprinted in* 4 "A Legislative History of the Clean Air Act Amendments of 1977," *Congressional Research Service*, 2662. The EPA interprets this legislative history as generally supportive of interpreting "standard of performance" to include an allowance/trading program because such a program accords flexibility to sources.

[13] This interpretation of the term "continuous" is consistent with the legislative history of that term. *See* H.R. Rep. No. 95–294 at 92, *reprinted in* 4 Congressional Research Service, A Legislative History of the Clean Air Act Amendments of 1977, 2559.

primarily from utilities.[14] These programs are contained in SIP that EPA has approved; and EPA is administering the trading programs. However, for most States, the requirements do not need to be implemented until May, 2004.

The success of the Acid Rain cap-and-trade program for utility SO_2 emissions, which EPA duplicated in large measure with the NO_X SIP Call cap-and-trade program for, primarily, utility NO_X emissions, leads EPA to propose to conclude that a cap-and-trade program for Hg emissions from utilities qualifies as the "best system of emission reductions" that "has been adequately demonstrated." A market system that employs a fixed tonnage limitation (or cap) for Hg sources from the power sector provides the greatest certainty that a specific level of emissions will be attained and maintained since a predetermined level of reductions is ensured. The EPA will administer a Hg trading program and will require the use of continuous emissions monitoring systems (CEMS) or an appropriate long-term method that will allow both EPA and sources to track progress, ensure compliance, and provide credibility to the trading component of the program. The advantages of the Hg trading program are discussed further below. We ask for comments on all aspects of this approach under section 111(d).

2. What Is the Regulatory Approach for Existing and New Sources?

What Are the National Hg Budget and Source Emission Limits?

Mercury budget overview. Our primary goal in this rulemaking is to reduce power plant emissions of Hg by 70 percent from today's levels by 2018. We are proposing to accomplish this goal by setting a 15 ton cap on these emissions in 2018. Under our proposal, the 2018 cap would be a permanent cap that could not be exceeded, regardless of future growth in the energy sector. Thus, the cap would effectively become more stringent as more and more plants are required to keep their collective emissions below 15 tons.

We also are proposing to set a near-term cap in 2010 at a level that reflects the maximum reduction in Hg emissions that could be achieved through the installation of FGD and SCR units that will be necessary to meet the 2010 caps for SO_2 and NO_X in our proposed IAQR. Although we know that FGD and SCR units reduce Hg emissions (as well as SO_2 and NO_X), there is significant uncertainty about the extent of the Hg reductions that these controls could achieve by 2010. Thus, we are seeking technical information that would allow us to establish an appropriate Hg cap in 2010.

The EPA believes that a carefully designed "multi-pollutant" approach—a program designed to control NO_X, SO_2, and Hg at the same time—is the most effective way to reduce emissions from the power sector. One key feature of this approach is the interrelationship of the timing and cap levels for SO_2, NO_X, and Hg. Today, we know that power plants can reduce their emissions of all three pollutants by installing FGD (which controls SO_2 and Hg emissions) and SCR (which controls NO_X and Hg). With respect to the first phase of Hg reductions, we have designed this proposal to take advantage of the combined emission reductions that these technologies provide. Therefore, we believe that the Phase I Hg cap should be set at a level that reflects the Hg reductions that would be achieved from the SO_2 and NO_X cap levels and corresponding control requirements in the IAQR that we also are proposing today.

A phase-one cap based on this approach would set a standard of performance based on the best system of emissions reduction that has been adequately demonstrated, consistent with section 111(d) of the Clean Air Act. Research currently indicates that Hg control technologies other than FGD and SCR—most notably activated carbon injection (ACI) and breakthrough technologies (*e.g.*, chemical systems to enhance removal efficiencies for wet scrubbers)—may one day allow facilities to reliably reduce Hg emissions to levels significantly below the levels achieved through application of FGD and SCR needed to satisfy SO_2 and NO_X control requirements. However, these technologies have not been adequately demonstrated on full-scale power plants. Moreover, current information on these technologies is not sufficient for us to conclude that they will be adequately demonstrated by 2010. Therefore, we believe that the 2010 cap for Hg should be set at a level that can be achieved through the installation of FGD and SCR needed to meet the 2010 SO_2 and NO_X caps in the proposed IAQR. Requiring additional FGD and SCR beyond those needed to meet the transport rule in order to further reduce Hg emissions by 2010 is not reasonable because the incremental cost of such a requirement for additional Hg reductions would be extremely high and the capacity of the equipment suppliers may be overwhelmed.[15]

Consistent with this framework, we are seeking comment and specific technical information concerning the 2010 cap level that should be set for Hg in the final rule. Almost 2 years ago, the Administration proposed Clear Skies legislation that would have established a 26 ton Hg cap in 2010. This cap was based on several factors, including modeling and policy analysis and technical information that was available at that time. Our most recent analysis, based on the most recent technical information, suggests that Hg emissions would be reduced to approximately 34 tons as a result of the FGD and SCR that will be installed to meet the 2010 caps for SO_2 and NO_X in the proposed IAQR. Modeling done by the Energy Information Agency (EIA) suggests that the controls required under our proposed IAQR would not reduce Hg to the extent that EPA is projecting. We are also aware that some stakeholders have recommended near-term Hg reductions that are lower than our estimates.

We recognize that there is and will be for the immediate future uncertainty about all these estimates. To a large extent, this uncertainty exists because we have relatively little direct experience and data about the Hg reductions that can be achieved through different combinations of FGD and SCR on different boiler types burning different ranks of coal, and because there is a high degree of variability in the data that we do have. For example, based on the ICR data, it appears that plants with very similar configurations, and that burn similar ranks of coal, often achieve significantly different levels of Hg control. Thus, if we receive additional technical information, we may be able to find that plants can better optimize their FGD and SCR units to achieve greater reductions in their Hg emissions than we currently estimate. We therefore seek any technical information, including information

[14] Non-electricity generating units (EGU) are also included in the States' programs.

[15] Analysis conducted in support of the proposed IAQR predicts that SO_2 scrubbers will be installed on 48.7 GW of existing coal-fired capacity to comply with the Phase I cap. The analysis also predicts that SCRs will be installed on 24.1 GW of capacity to reduce NO_X emissions. In addition, we predict that existing SCRs that are currently operated on a seasonal basis (*i.e.*, for the ozone season) will under the IAQR be operated for the entire year. These technologies (FGD and SCR) have been developed to reduce SO_2 and NO_X emissions. However, they do realize collateral reductions in Hg, although these reductions are variable (and somewhat uncertain) across types of coal and other control technologies used for treatment. The available modeling suggest that these NO_X and SO_2 controls are predicted to reduce Hg emissions from the power sector to a level of approximately 34 tons per year.

about incremental costs and benefits, that provides the basis for any of the levels mentioned above or other proposals for a near-term cap.

As noted above, EPA is proposing a 15 ton cap in 2018 from coal-fired electric generating facilities. This proposed cap reflects a level of Hg emissions reduction that almost certainly exceeds the level that would be achieved through the installation of FGD and SCR needed to meet the SO_2 and NO_X caps in the proposed IAQR. We conclude that this approach is warranted because we fully expect other Hg air pollution control technologies such as ACI and/or one or more of the breakthrough technologies will have been adequately demonstrated before 2018, making it possible to begin achieving much greater reductions in Hg between 2010 and 2018. This conclusion relies on the fact that the small number of current-day pilot scale ACI projects at Utility Units and the innovative technologies will yield information that will be usable in implementing similar pilot scale projects at other facilities. Data from these pilot studies ultimately will allow companies to design full scale applications that will provide reasonable assurance that emissions limitations can be reliably achieved over extended compliance periods. We do not believe that such full scale technologies can be developed and widely implemented within the next 6 years; however, it is reasonable to assume that this can be accomplished over the next 14 years.

Our proposed 15 ton cap in 2018 is grounded largely in the modeling completed in support of the President's Clear Skies initiative. This modeling suggests that, assuming technologies such as ACI become available, such a cap will create an incentive for certain plants to install these newer technologies. It also suggests that such controls should not have any significant impact on power availability, reliability, or pricing. Nor should a 15-ton cap cause any significant shift in the fuels currently utilized by power plants or in the source of these fuels. Sensitivity analyses indicate that a more stringent cap could have potentially significant impacts on fuels and/or power availability, reliability, or pricing. Less stringent caps do not appear warranted based on our expectations about technology development and our modeling analysis of the potential impacts of the 15-ton cap.

The Agency continues to investigate whether the mandatory 70 percent reduction in Hg emissions will be adequate to eliminate public health risks from local Hg deposition near plants because of scientific and technical uncertainties. The Agency requests comment on this issue.

The EPA is also proposing a method for apportioning the nation-wide budget to individual unit sources. The EPA maintains that the emission budget provides an efficient method for achieving necessary reductions in Hg emissions (as described in earlier sections of this preamble), while providing substantial flexibility in implementing the program.

The EPA has concern about Utility Units with low Hg emissions rates (*e.g.*, emitting less than 25 pounds per year) because the new, Hg-specific control technologies that we expect to be developed prior to the Phase II cap deadline may not practicably apply to such units period. Our data indicate that the 396 smallest emitting coal-fired Utility Units currently account for less than 5 percent of total Hg emissions. There is reason to believe that the 15 ton Phase II cap can be achieved in a cost-effective manner, even if the lowest emitting 396 units are excluded from coverage under this cap. Thus, the EPA is soliciting comment on the possibility of excluding from the Phase II cap units with low Hg emissions rates (*e.g.*, emitting less than 25 pounds per year).

In today's notice of proposed rulemaking, EPA is also proposing that allowances are allocated to affected Utility Units based on the proportionate share of their baseline heat input to total heat input of all affected units. For purposes of allocating the allowances, each unit's baseline heat input is adjusted to reflect the ranks of coal combusted by the unit during the baseline period. The sum of the unit emission allowances in a State would be considered the State's emissions budget. If States choose not to participate in the trading program, the State budgets and unit emission allocations will become the required maximum emission limit. States also can require emissions reductions beyond those required by the State budget and unit emission limits.

As discussed elsewhere in this preamble, new sources will comply with NSPS standards for Hg. In addition, new sources will be covered under the Hg cap of the trading program, and will be required to hold allowances equivalent to the product of their NSPS and baseline heat input. The EPA proposes that these sources not receive an adjustment to their allocated share of allowances since they are required to meet NSPS, which may increase total emissions but will maintain required emissions rates.

Rationale for source level limits (allowances). Unit-level emissions limits will be proposed in a supplemental notice entitled "Emission Guidelines and Compliance Times for Coal-fired Electric Utility Steam Generating Units." If a State chooses to participate in the trading program, these unit-level emission limits can be adopted as unit-level allocations for the trading program. Additionally, the trading program provides the individual States the discretion in choosing how to allocate their respective budget allocations.

Different ranks of coal may achieve different Hg reductions depending on the control equipment installed at the unit. In order to distribute unit limits equitably, EPA is proposing that Hg emission limits (allowances if State is participating in a trading program) are distributed to existing coal units based on their share of total heat input. This is then adjusted to reflect the concern that the installation of PM, NO_X, and SO_2 control equipment on different coal ranks results in different Hg removal.

The adjustment factors of 1 for bituminous, 1.25 for subbituminous, and 3 for lignite coals are based on the expectation that Hg in the coal ranks reacts differently to NO_X and SO_2 control equipment and that the heat input of the different coal ranks varies. The conclusion that Hg in each of the coals reacts differently to NO_X and SO_2 control equipment was based on information collected in the ICR as well as more recent data collected by EPA, DOE, and industry sources. This information, which was collected from units of various coal ranks and control equipment configuration, indicated differing levels of Hg removal. The test data indicated that installation of PM, NO_X, and SO_2 controls on plants burning bituminous coals resulted in greater Hg reduction on average than plants burning subbituminous coals or lignite coals. Likewise, the test data indicated that installation of PM, NO_X, and SO_2 controls on plants burning subbituminous coals resulted in somewhat greater Hg removal than plants burning lignite coals. On average, units burning lignite coal showed the least Hg removal of the three coal ranks. See section C.4 for further discussion on subcategorization approaches considered under this proposal.

Under the proposed emission limit or allocation methodology, bituminous units would be allocated a share of the allowances 1.0 times their share of the overall heat input, subbituminous units would be allocated a share of the allowances 1.25 times their share of the overall heat input, and lignite units would be allocated a share of the allowances 3.0 times their share of the overall heat input. These adjustment factors are considered to be directionally correct based on the test data currently available; however, we realize that these factors do not in all cases accurately predict relative rates of Hg emissions from Utility Units with NO_X and SO_2 controls. Our goal, however, is not to have the factors achieve such a result. Rather, the factors are intended to equitably distribute allowances to the affected industry. The EPA is taking comment on the appropriateness of these adjustment factors. Since new sources are required to meet NSPS, EPA is proposing new sources will not receive an adjustment to their allocated share.

Distribution of State budgets. The trading program establishes a cap on Hg emissions for affected electric generating units of 15 tons starting in 2018. The proposed unit level emission limits (allocations) are the basis for establishing State budgets with the State budgets equaling the total of the individual unit emission limits in a given State (*see* Table 5 of this preamble below). States also have the flexibility to not participate in the trading program or require more stringent Hg emissions reductions. For States that do not participate in the trading program, the proposed unit level allocations will become fixed, unit level emissions limitations.

TABLE 5.—DISTRIBUTION OF STATE BUDGETS

State	Phase II budget (tons)
Alabama	0.506
Alaska	0.002
Arizona	0.289
Arkansas	0.202
California	0.016
Colorado	0.277
Connecticut	0.023
Delaware	0.029
District of Columbia	0.000
Florida	0.491
Georgia	0.483
Hawaii	0.009
Idaho	0.000
Illinois	0.635
Indiana	0.833
Iowa	0.284
Kansas	0.281
Kentucky	0.605
Louisiana	0.236
Maine	0.001
Maryland	0.186
Massachusetts	0.070
Michigan	0.517
Minnesota	0.274
Mississippi	0.114
Missouri	0.545
Montana	0.148
Nebraska	0.165
Nevada	0.112
New Hampshire	0.025
New Jersey	0.060
New Mexico	0.240
New York	0.157
North Carolina	0.451
North Dakota	0.614
Ohio	0.810
Oklahoma	0.285
Oregon	0.030
Pennsylvania	0.710
Rhode Island	0.000
South Carolina	0.226
South Dakota	0.028
Tennessee	0.378
Texas	1.837
Utah	0.224
Vermont	0.000
Virginia	0.234
Washington	0.077
West Virginia	0.554
Wisconsin	0.353
Wyoming	0.375

Model cap-and-trade program. The EPA is outlining a national cap-and-trade program that States may choose as a cost-effective mechanism to achieve the emissions reductions requirements in today's rulemaking. The trading program will meet these requirements by utilizing a cap on total emissions in order to ensure that emissions reductions under today's proposed rulemaking are achieved, while providing the flexibility and cost effectiveness of a market-based system. This section provides background information and a description of the trading program and an explanation of how the trading program would interface with other State and Federal programs. It is EPA's intent to propose a model rule in a future supplemental notice.

States can voluntarily choose to participate in the trading programs by adopting the model rule, which is a fully approvable control strategy for achieving emissions reductions required under the proposed section 111 rulemaking. Should the States voluntarily choose to participate in the trading program by adopting the model rule, EPA's authority to cooperate with and assist the States in the implementation of the trading program resides in both State law and the CAA. With respect to State law, any State which elects to adopt the model rule as part of its section 111 SIP-like rule will be authorizing EPA to assist the State in implementing the trading program with respect to the sources in that State. With respect to the CAA, EPA believes that the Agency's assistance to those States that choose to participate in the trading program will facilitate the implementation of the program and minimize administrative burden on the States.

Purpose of the trading program and model rule. In the trading program, EPA is proposing to jointly implement with participating States a capped market-based program for certain Utility Units to achieve and maintain an emissions budget consistent with the proposed section 111 rulemaking. Specifically, today's proposal is designed to assist States in: (1) Achieving emissions reductions required under the proposed section 111 rulemaking; (2) ensuring flexibility for regulated sources; (3) reducing compliance costs for sources; and (4) reducing administrative costs to States. In addition to these benefits of electing to participate in the proposed trading program, EPA also seeks to create as simple a regulatory regime as possible by applying a single, comprehensive regulatory approach to all of the affected jurisdictions.

Beyond choosing to use the proposed trading program, State adoption of the model rule would ensure consistency in certain key operational elements of the program among participating States, while allowing each State flexibility in other important program elements. Uniformity of the key operational elements across the participating states would ensure a viable and efficient trading program with low transaction costs and minimum administrative costs for sources, States, and EPA.

Emissions reductions required by the proposed section 111 rulemaking.

State-level emission budgets. Each of the States and the District of Columbia covered by today's proposal has been assigned a statewide emissions budget for Hg. The statewide budgets were developed by totaling unit-level emissions reductions requirements for coal-fired electricity generating devices. The statewide budget development process is fully described elsewhere in today's preamble. States have the flexibility to meet these State budgets by participating in a trading program or requiring source level reductions to coal-fired electric generating units. States have the ability to require reductions beyond those required by the state budget.

Geographic scope of trading program. As discussed elsewhere in this preamble, today's proposal would apply to all coal-fired Utility Units located in all 50 states of the U.S.

Each State has been assigned a statewide emissions budget for Hg. Each of these States must submit a SIP-like plan detailing the controls that will be implemented to meet its specified budget for reductions from electric generating units. Therefore, should some States choose to achieve the mandated reductions by using an approach other than the proposed emissions trading rule, the geographic scope of the trading program would not be nationwide.

Some stakeholders have noted that modeling results suggest that Hg deposition from emissions from Utility Units may be higher in certain regions of the country (*e.g.*, the upper Ohio Valley and Mid-Atlantic areas). In addition, the ecosystems in some regions (*e.g.*, the lakes regions of the Upper Midwest) may be more sensitive to Hg deposition. As discussed more fully below, given the 70 percent emission reduction in the proposed section 111 rule and our experience with cap-and-trade systems, EPA does not expect any local or regional hot spots. The EPA is interested in comments on whether it would be appropriate to adjust the geographic scope of this program to introduce trading ratios between regions as a way of addressing regional differences should they occur. For example, EPA could require that eastern Utility Units in areas of heavy deposition would need greater than 1:1 allowances from Utility Units outside the region to cover an ounce of Hg emissions. The EPA is interested in comments on whether such an approach is appropriate, and if so, on the way to identify appropriate regions where a higher trading ratio would apply and the appropriate magnitude of the trading ratio. The EPA is also interested in comments on the extent to which these adjustments would complicate and reduce the efficiency of the cap-and-trade program.

Affected sources in the trading program. The model trading rule applies to coal-fired Utility Units. The term "electric utility steam generating unit" means any fossil fuel fired combustion unit that serves a generator of more than 25 MW that produces electricity for sale. A unit that cogenerates steam and serves a generator that supplies more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale shall be considered an Utility Unit.

Benefits of participating in the trading program. Advantages of cap-and-trade over command-and-control. When designed and implemented properly, a market-based program offers many advantages over its traditional command-and-control counterpart. *See* discussion, *supra*, Section III. Six principal advantages of market-based systems have been recognized: (1) Results in a certain, fixed cap in emissions from affected and potentially affected sources; (2) potential for the creation of incentives for early reductions; (3) creation of incentives for emissions reductions beyond those required by regulations; (4) reduced cost of compliance for individual sources and the regulated community in general; (5) promotion of innovation and continued evolution of production and pollution control technology; and, (6) increased flexibility for the regulated community without resorting to waivers, exemptions and other forms of administrative relief. These benefits result primarily from the flexibility in compliance options available to sources and the monetary reward associated with avoided emissions in a market-based system. The cost of compliance in a market-based program is reduced because sources have the freedom to pursue various compliance strategies, such as switching fuels, installing pollution control technologies, or buying authorizations to emit from a source that has over-complied. Since emissions level below the level mandated allows the freeing up of allowances that may be sold on the market, pollution prevention becomes more cost effective, and innovations in less-polluting alternatives and control equipment are encouraged.

A market system that employs a fixed tonnage limitation (or cap) for a source or group of sources provides the greatest certainty that a specific level of emissions will be attained and maintained since a predetermined level of reductions is ensured. With respect to transport of pollution, an emissions cap also provides the greatest assurance to downwind States that emissions from upwind States will be effectively managed over time. The capping of total emissions of pollutants over a region and through time ensures achievement of the environmental goal while allowing economic growth through the development of new sources or increased use of existing sources. In an uncapped system (where, for example, sources are required only to demonstrate that they meet a given emission rate) the addition of new sources to the regulated sector or an increase in activity at existing sources can increase total emissions even though the desired emission rate control is in effect.

In addition, the reduced implementation burden for regulators and affected sources benefits taxpayers and those who must comply with the rules. This streamlined administrative approach allows a small number of government employees to successfully regulate many sources by (1) minimizing the necessity for case-by-case rules and (2) taking full advantage of electronic communication and data transfer to track compliance and develop detailed, critical inventories of emissions and plant operations.

Application of the cap-and-trade approach in prior rulemakings. Title IV. Title IV of the 1990 Amendments to the CAA established the Acid Rain Program, a program that utilizes a market-based cap-and-trade approach to require power plants to reduce SO_2 emissions by 50 percent from 1980 levels by 2010. At full implementation after 2010, emissions will be limited, or capped, at 8.95 million tons. It also includes emission rate requirements to reduce NO_X emissions. The Acid Rain Program for SO_2 is widely acknowledged as a model air pollution control program because it provides significant and measurable environmental and human health benefits with low implementation costs.

Units are allocated their share of the total allowances, each allowance providing an authorization to emit a ton of SO_2, based upon historical records of the heat content of the fuel that they combusted during the period 1985 to 1987. Units that reduce their emissions below the number of allowances they hold may trade allowances with other units in their system, sell them to other sources on the open market or through EPA auctions, or bank them to cover emissions in future years. Each affected unit is required to surrender allowances to cover its emissions each year. Should any unit fail to hold sufficient allowances, automatic penalties apply. In addition to financial penalties, units either will have allowances deducted immediately from their accounts to offset their allowance deficiencies or, if such deduction would threaten electric reliability, may submit a plan to EPA that specifies when the allowances will be deducted in the future.

An essential feature of the Acid Rain Program is the requirement for affected sources to install systems that continuously monitor emissions. The use of CEMS was an important innovation that allowed both EPA and sources to track progress, ensure compliance, and provide credibility to the trading component of the program.

While title IV does provide for an Acid Rain Permit, the permit simply states a non-source specific requirement that sources comply with the standard rules of the program. Acid Rain permitting has been easily incorporated into the title V permit process and does not require the typically resource intensive, case-by-case review associated with other permits under command-and-control programs.

The Acid Rain Program has achieved major SO_2 emissions reductions, and associated air quality improvements, quickly and cost-effectively. In 2002, SO_2 emissions from power plants were 10.2 million tons, 41 percent lower than 1980. True to its intent, the program has substantially reduced acid deposition, allowing lakes and streams in the Northeast to begin recovering from decades of acid rain. The Acid Rain Program resulted in emission reductions well below the cap in the areas that contribute most of the sulfur in the acid rain. Comparing emissions from the 263 power plants regulated in the first phase of the program in 1999 with those in 1990, the North Central and Southeast and Mid-Atlantic regions achieved 49 percent, 48 percent and 43 percent reductions in SO_2, respectively. Several analyses of trading under the acid rain program have concluded that the program did not result in local areas with "hot spots."

Trading under the Acid Rain Program has created financial incentives for electricity generators to look for new and low-cost ways to reduce emissions, and improve the effectiveness of pollution control equipment, at costs much lower than predicted. In fact, the Acid Rain Program achieved reductions at two-thirds the cost of achieving the same reductions under a command-and-control system. The cap on emissions and significant automatic penalties for noncompliance ensure that environmental goals are achieved and sustained, while stringent emissions monitoring and reporting requirements make flexibility possible. The level of compliance under the Acid Rain Program continues to be uncommonly high, measuring over 99 percent.

NO_X SIP call and OTC Trading Program. The cap-and-trade approach has also been used to address regional ozone transport problems in the eastern U.S. The north-eastern states (Ozone Transport Commission) began implementing a cap-and-trade program to address regional ozone transport in 1999. The NO_X Budget Trading Program under the NO_X SIP Call began its first year of implementation in 2003 in the Northeast. Eleven additional States will join in 2004. Each of the States required to submit a NO_X SIP to address the regional transport of ozone chose to participate in the interstate trading program. They each based their trading program on the model rule; some states essentially adopted it in full, other states modified some provisions for their unique circumstances.

Local environmental improvements achieved using cap-and-trade model. Mercury emissions from power plants sometimes are deposited locally near the plant. Nearby lakes may be a source of fish consumption for recreational and/or subsistence fisherman, and thus local Hg deposition in nearby lakes could be a source of what are called hot spots. In this discussion, we are assuming that a power plant may lead to a hot spot if the contribution of the plant's emissions of Hg to local deposition is sufficient to cause blood Hg levels of highly exposed individuals near the plant to exceed the RfD. For the purposes of choosing a regulatory tool to address hot spots, the relevant question is what is the contribution of these plants to hot spots under a cap-and-trade approach, relative to their current contribution and their projected contribution under a traditional section 112 approach.

Concerns about hot spots have been raised despite the success and growing use of cap-and-trade programs. The EPA believes that a trading approach will help to address this problem. In addition to reductions required by the cap, all States would have the ability to address local health-based concerns separate from the Hg cap-and-trade program requirements.

The EPA does not anticipate significant local health-based concerns under a national Hg trading program. The Agency has considered this possibility and believes that the cap-and-trade system, coupled with related Federal and State programs, will effectively address local risks. This has been EPA's experience with the title IV program limiting SO_2 emissions.

First, modeling runs suggest that large coal-fired Utility Units—those that tend to have relatively high Hg emissions—are likely to have larger local deposition footprints than medium-sized and smaller coal-fired Utility Units. However, the trading of allowances is likely to involve large Utility Units controlling their emissions more than required and selling allowances to smaller Utility Units rather than the reverse scenario. This prediction arises from the basic economics of capital investment in the utility industry. Under a trading system where the firm's access to capital is limited, where the up-front capital costs of control equipment are significant, and where emission-removal effectiveness (measured in percentage of removal) is unrelated to plant size, it makes more economic sense for the utility company to allocate pollution-prevention capital to its larger facilities than to the smaller plants (since more allowances will be earned). Any economies of scale of pollution control investment will favor investment at the larger plants. Insofar as large coal-fired Utility Units tend to be newer and/or better maintained than medium-sized and small facilities, it can be expected that companies will favor investments in plants with a longer expected lifetime.

Second, the types of Hg that are deposited locally—Hg^{++} and particulate Hg (Hg_p)—are controlled by the same equipment that controls criteria air pollutants (fine particles, SO_2 and NO_X). These same types of Hg are more likely to be deposited locally than Hg^0. As utilities invest in equipment to comply with the Agency's new fine particle and ozone control regulations (*e.g.*, today's proposed IAQR, and new State Implementation Plans (SIP) for fine particles and ozone), the Agency expects a "co-benefit" in Hg control as controls such as particulate controls, scrubbers and SCR units are installed on an increasing percentage of coal-fired Utility Units. The type of Hg that is most difficult to control is Hg^0, and it is this gaseous form of Hg that is most likely to be transported long distances from the Utility Units. Effective control of Hg^0 may require significant investment in Hg-specific control technologies that are only beginning to reach the commercialization stage.

Considering the economies of Hg trading, Utility Units that have significant emissions of Hg^0 may become buyers of allowances from plants that can cost-effectively control Hg^{++} and Hg_p. Consequently, the economics of the trading system are likely to favor controls of Hg that are likely to be deposited locally, thereby reducing any local hot spots.

The structure of the proposed rule permits States to adopt more stringent performance standards if the State determines that such regulations are necessary. Although more stringent State regulations will reduce flexibility built into the cap-and-trade system, States retain the power under the proposed section 111 rule to adopt stricter regulations to address local hot spots or other problems. Given the 70 percent emission reduction in the proposed section 111 rule and our experience with cap-and-trade systems, which shows that the largest emitters are the first to install stringent emission controls, we do not expect any local or regional hot spots. However, the Agency plans to continue monitoring Hg emissions and the operation of the trading system to make sure that localized hot spots do not materialize.

As part of its analysis of the President's Clear Skies initiative, EPA analyzed Hg emissions reductions under a cap-and-trade mechanism. In the Clear Skies example, the greatest emissions reductions were projected to occur at the electric generating sources with the highest Hg emissions. This pattern is similar to that observed in the SO_2 emissions trading program under the Acid Rain Program. Under Clear Skies, compared to a base case of existing programs, ionic Hg emissions (those Hg emissions which tend to be deposited locally, *i.e.*, within 25 kilometers) from power plants located up to 10 kilometers from a water body were projected to decrease by over 60 percent in 2020. In addition, based on regional-scale Hg deposition model predictions, Clear Skies could reduce Hg deposition by 5 to 15 percent beyond the existing program base case across much of the eastern U.S. and could do so to higher levels in certain specific locations. Based on this available information, the proposed cap-and-trade mechanism in this regulatory proposal can be expected to reduce Hg deposition similarly in most areas. Consequently, the EPA does not anticipate significant local health-based concerns under a national Hg trading program.

We explain elsewhere in this proposal our intention to take a hard look at the Hg emissions inventory after full implementation of the first phase cap. The main purpose of this review is to determine whether the actual reductions achieved under this program significantly differ from the outcome predicted by our current analysis. We retain authority to make adjustments to the program if we find remaining areas with heavy, localized emissions and higher health risks (*i.e.*, if we find "hot spots").

In the final days before signature and publication of this proposal, concerns about the possibility of "hot spots" under our proposed cap and trade program were widely reported. We agree that this is an important issue and believe that our program will effectively address potential "hot spots." We ask for comment on this issue. We are particularly interested in receiving site-specific data and information about locations where commenters believe "hot spots" will continue to exist after implementation of these rules.

State adoption of the model rule. Participation in the trading program would enable States that have been identified in the proposed section 111 rulemaking to achieve the required emissions reductions from stationary combustion sources while minimizing the administrative burden faced by both States and sources. The SIP-like rule process required by the proposed rulemaking would be significantly streamlined for States choosing to include the trading program as a part of the SIP-like rule. The EPA proposes that adoption of the model rule, to be published in a future supplemental notice of proposed rulemaking (SNPR), will be considered a SIP-approvable control strategy for the proposed section 111 rulemaking. States electing to participate in the trading program may either adopt the model rule by reference or develop State regulations that are in accordance with the model rule.

The permitting process under the trading program would be significantly streamlined since there will be no need for enforceable compliance plans and source-specific requirements (each permit will have to be revised to add Hg trading program requirements). Emissions monitoring, a central requirement of the trading program, as well as the availability to the public of emissions data, allowance data, and annual reconciliation information, would ensure that participating States and the public have confidence that the required emissions reductions are being achieved.

States that elect to participate in the trading program, thereby allowing sources to seek the least-cost reductions, are expected to see substantially lower compliance costs for their sources than under a comparable rate based program.

Sources included in the trading program also benefit from increased compliance flexibility, as compared to a rate-based approach that requires each affected source to comply with an emission rate and necessitates installation of control equipment for any affected source that cannot meet the limit. Participation in the trading program provides sources the choice of numerous compliance strategies. Moreover, sources can choose to over-comply and free up excess allowances that can be sold on the market or, as discussed below, possibly banked for future use. In addition, sources may change their control approach at any time without regulatory agency approval.

The Hg trading program. Brief description of Hg trading program. The trading program establishes a first phase cap at a level that reflects the Hg reductions expected with the SO_2 and NO_x in the IAQR in 2010 and a Phase II cap of 15 tons on Hg emissions for affected Utility Units starting in 2018. The new trading program for Hg would require sources to hold allowances covering emissions beginning January 1, 2010. The EPA is proposing that the owner or operator must hold allowances for all the affected Utility Units at a facility at least equal to the total Hg emissions for those units during the year. Compliance with the requirement to hold allowances will thus be determined on a facility-wide basis. In a supplemental notice entitled "Emission Guidelines and Compliance Times for Coal-fired Electric Utility Steam Generating Units" EPA will be proposing unit allocations for existing units. New units will be covered under the Hg cap of the trading program and will be required to hold allowances. In the SNPR, EPA will recommend options for States to address the inclusion of new sources (*e.g.*, new source set asides and/or updating allocations).

Applicability. The model trading rule applies to coal-fired combustion units serving a generator of more than 25 MW that produces electricity for sale. A unit that cogenerates steam and supplies more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale shall be considered an Utility Unit.

State trading budgets. This proposal establishes the total number of tons for the Budget Trading Program within a specific State. The proposed rule sets the State's unit level allocations and adds up those allocations to develop a State level budget.

In a supplemental notice entitled "Emission Guidelines and Compliance Times for Coal-fired Electric Utility Steam Generating Units," EPA will be taking comment on the proposed methodology for establishing unit level allocations and the data used to develop these allocations. As discussed earlier, unit allocations were determined by adjusting a baseline heat input. That baseline heat input was determined using the average of the three highest heat inputs of the period 1998 to 2002. In order to adjust the heat input based on coal type, coal usage patterns were determined from the ICR data. The EPA requests comment on the data used to develop proposed unit-level allocation. The EPA also requests comment on the appropriateness of using 1999 data to determine the coal adjustment factors.

In today's proposal, EPA is proposing a safety valve provision that sets a maximum cost for Hg emissions reductions. This provision addresses some of the uncertainty associated with the cost of Hg control. In fact, there is an ongoing research process sponsored by EPA, the DOE, the Electric Power Research Institute (EPRI), and vendors specifically aimed at furthering our understanding of Hg control, with new data being made available on a continuous basis.

Under the safety valve mechanism, the price of allowances is capped, meaning that if the allowance price exceeds the "safety-valve," sources may borrow allowances from following years to have access to more allowances available at that price. The EPA proposes a price of $2,187.50 for a Hg allowance (covering one ounce). This price will be annually adjusted for inflation. The Administrator will deduct corresponding allowances from future facility allowance accounts.

The purpose of this provision is to minimize unanticipated market volatility and provide more market information that industry can rely upon for compliance decisions. The safety valve mechanism ensures the cost of control does not exceed a certain level, but also ensures that emissions reductions are achieved. The future year cap is reduced by the borrowed amount, and the emissions reductions are achieved.

We note that this proposed approach may create implementation problems associated with the need to "reconcile" at some point in time the allowances borrowed from future compliance periods. We ask for comment on the need for a safety valve and the viability of our proposed approach, and solicit suggestions for other viable approaches.

We also ask for comment on the possibility of conducting auctions each year, at which allowances would be offered for sale. The pool of allowances to be auctioned would be created by specified procedures, such as setting aside a fixed or incremented percentage of allocations each year. The auctions would be open to any person. A person wishing to bid for allowances in the auction would submit bids according to auction procedures, a bidding schedule, a bidding means, and requirements for financial guarantees specified in the regulations. Winning bids, and required payments, for allowances would be determined in accordance with the regulations. For any winning bid, we would record the allowances in a tracking system only after the required payment for such allowances is received. If we decide to provide for auctions, we would need to determine how to collect and properly disperse the revenues. We believe that responsibility for managing this aspect of the program would necessarily fall to the individual states that opt to participate in the cap and trade program. We ask for comment on all aspects of this auctions proposal. If we decide to proceed, details of the auction program would be spelled out in the upcoming SNPR.

Key elements of Hg model cap-and-trade rule to be proposed in SNPR. Allowance allocations. The EPA is proposing heat input-based allocations for existing coal units (with different ratios for different coal types).

The EPA believes that allocating based on heat input data is desirable because accurate protocols exist for monitoring this data and reporting it to EPA, and several years of certified data are available for most of the affected sources.

New sources will be covered under the Hg cap of the trading program and will be required to hold allowances equivalent to the product of their NSPS standard and a baseline heat input. Therefore, state budgets will be maintained at the levels proposed in today's rulemaking even after the addition of new coal-fired electricity generating units in the state. State SIP-like rules will need to address the inclusion of these new sources in their state budget. In the SNPR, EPA will recommend options for states to address the inclusion of new sources (*e.g.*, new source set asides and/or updating allocations).

Allowance management system, compliance, penalties, and banking. Each of these elements is part of the accounting system that enables the functioning of a trading program. An accurate, efficient accounting system is critical to an emissions trading market. Transparency of the system, allowing all interested parties access to the information contained in the accounting system, increases the accountability of regulated sources and contributes to reduced transaction costs of trading allowances.

In order to guarantee the equitable treatment of all affected sources across the trading region, the elements included in this section need to be incorporated in the same manner in each state that participates in trading.

Allowance management. The EPA intends to propose a model trading rule that will be reasonably consistent with the existing allowance tracking systems that are currently in use for the Acid Rain Program under title IV and the NO_X Budget Trading Program under the NO_X SIP Call. These two systems are called the Allowance Tracking System (ATS) and the NO_X Allowance Tracking System (NATS), respectively. Under the section 111 trading rule, EPA would maintain a separate system for Hg, Mercury Allowance Tracking System (MATS). The MATS would be established as an automated system used to track Hg allowances held by affected units under the Hg cap-and-trade program, as well as those allowances held by other organizations or individuals. Specifically, MATS would track the allocation of all Hg allowances, holdings of Hg allowances in accounts, deduction of Hg allowances for compliance purposes, and transfers between accounts. The primary role of MATS, in conjunction with an emissions tracking system, is to provide an efficient, automated means of monitoring compliance with the trading programs. The MATS also provide the allowance market with a record of ownership of allowances, dates of allowance transfers, buyer and seller information, and the serial numbers of allowances transferred.

Compliance. Compliance in the trading program consists of the deduction of allowances from affected facilities" accounts to offset the quantity of emissions at the facilities. The EPA plans to propose that compliance be assessed at the facility level, rather than the unit level as is currently done in both the Acid Rain and NO_X Budget trading programs.

Penalties. The EPA plans to propose a system of automatic penalties should a facility not obtain sufficient Hg allowances to offset emissions for the compliance period. The automatic penalty provisions will not limit the ability of the permitting authority or EPA to take enforcement action under State law or the CAA.

Banking. Banking is the retention of unused allowances from 1 year for use in a later calendar year. Banking allows sources to create reductions beyond required levels and "bank" the unused allowances for use later. Generally speaking, banking has several advantages: it can encourage earlier or greater reductions than are required from sources, stimulate the market and encourage efficiency, and provide flexibility in achieving emissions reduction goals. On the other hand, it may result in banked allowances being used to allow emissions in a given year to exceed the trading program budget. The EPA plans to propose that banking of allowances after the start of the Hg trading program be allowed with no restrictions.

Emissions monitoring and reporting. Monitoring and reporting are an integral part of any cap-and-trade program. Consistent and accurate quantification of emissions ensures each allowance actually represents one ounce of emissions and that one ounce of reported emissions from one source is equivalent to one ounce of reported emissions from another source. This establishes the integrity of the allowance (*i.e.*, the authorization to emit one ounce of Hg) and instills confidence in the market mechanisms that are designed to provide sources with flexibility in achieving compliance. Given the variability in the type, operation and fuel mix of sources in the cap-and-trade program, EPA believes that to ensure this accuracy and consistency, emissions must be monitored using continuous emissions monitoring methods. As discussed earlier, EPA plans to include in the model trading rule a requirement for States to require year-round Part 75 monitoring and reporting for all sources.

Accountability for affected sources. Key to the success of existing cap-and-trade programs and the integrity of the emission allowance trading markets has been clear accountability for a source's emissions. This takes the form of affected sources officially designating a specific person (and alternate) that is responsible for the official certification of all allowance transfers and emissions monitoring and reporting as submitted to EPA in quarterly compliance reports. With each quarterly submission, this responsible party must certify that: (1) the monitoring equipment data were reported in compliance with the monitoring and reporting requirements, and (2) the emission and operation reports are true, accurate, and complete.

The trading program to be proposed in the future SNPR will include provisions to provide for the same strict standards for source accountability established in the Acid Rain Program and the NO_X SIP call. This will include provisions for the establishment and management of an Authorized Account Representative. Adoption of these provisions will be required by all States that wish to participate in the trading program.

3. What Are the Subpart Da Hg Emission Guidelines?

This information will be provided in the Emission Guidelines, which will be provided in an upcoming supplemental notice.

4. How Did EPA Select the Format for the Proposed Emission Guidelines?

This information will be provided in the Emission Guidelines, which will be provided in an upcoming supplemental notice.

5. How Did EPA Determine the Emissions Monitoring and Reporting Requirements for the Proposed Emission Guidelines?

Monitoring and reporting are an integral part of any Hg reduction program, including a cap-and-trade program. Consistent and accurate quantification of emissions ensures the integrity of a Hg reduction program. The continuous emissions monitoring methods must incorporate rigorous quality assurance testing and substitute data provisions for times when monitors are unavailable because of planned and unplanned outages. In addition, there must be requirements for record keeping and electronic reporting. Provisions like these are contained in 40 CFR part 75, and are used in both the Acid Rain and NO_X SIP Call programs, for SO_2 and NO_X, but not currently for Hg.

In an effort to maintain program integrity, the EPA plans to propose revisions to 40 CFR part 75 to establish requirements for emission monitoring, quality assurance, substitute data, record keeping, and reporting and to include in the SNPR a requirement for States to require year-round Part 75 monitoring and reporting for all sources. Monitor certification deadlines and other details will be specified in the SNPR. The EPA believes that emissions will then be consistently and accurately monitored and reported from unit to unit and from State to State.

The EPA also intends to require year-round reporting of emissions and monitoring data from each unit at each affected facility. A single report for Hg will be required on a quarterly basis in a format specified by the EPA. The reports will be required to be in an electronic data reporting (EDR) format and must be submitted to EPA electronically. The reports will be maintained in EPA's Emissions Tracking System (ETS). This centralized reporting requirement is necessary to ensure consistent review, checking, and posting of the emissions and monitoring data at all affected sources, which contributes to the integrity of the Hg reduction program.

6. How Did EPA Determine the Compliance Times for the Proposed Emission Guidelines?

This information will be provided in the Emission Guidelines, which will be provided in an upcoming supplemental notice.

E. Rationale for the Proposed Ni Guidelines

1. What Is the Rationale for the Proposed Subpart Da Ni Emission Guidelines?

The proposed emission guidelines for Ni from existing oil-fired units was determined by analyzing the emissions data available. The data were obtained from the Utility RTC which provided information indicating that Ni was the pollutant of concern due to its high level of emissions from oil-fired units and the potential health effects arising from exposure to it. The EPA examined available test data and found that ESP-equipped units can effectively reduce Ni. Analysis of the available emissions data indicated that existing oil-fired units can limit Ni emissions to 210 lb/TBtu input or 0.002 lb/MWh output gross. The EPA is proposing both an input-based and an output-based standard in the proposed rule for existing sources (based on potential difficulties in retrofitting the necessary data acquisition measures for the output-based standard at an existing source).

The EPA is sensitive to the fact that some sources burn fuels containing very little Ni. Therefore, EPA solicits comment on a Ni-in-oil limit that would be equivalent to the proposed stack values of 210 lb/TBtu input or 0.002 lb/MWh gross. With a limit on the amount of Ni in the oil, an existing source could choose to comply with an alternate oil-content-based Ni emission limitation instead of the stack Ni emission limit to meet the proposed rule. Such an alternate Ni-in-oil limit could be useful where Ni constituent levels are low in the fuel.

Two alternatives for compliance purposes are provided in the proposed rule for oil-fired units. The owner/operator can elect to: (1) Meet the standard of performance for Ni, or (2) burn distillate oil (exclusively) rather than residual oil. If an oil-fired unit is currently burning, or switches to burning, distillate oil (exclusively), it would be exempt from all oil-fired unit initial and continuous compliance requirements until such time as it begins burning any oil other than distillate oil. The proposed rule would require that the exempted oil-fired unit begin the performance testing procedures if it resumes burning a fuel other than distillate oil.

2. How Did EPA Address Dual-Fired (Oil/Natural Gas) Units?

The EPA is aware that an oil-fired unit may fire oil at certain times of the year and natural gas at other times. The choice of when to fire oil or natural gas is usually based on the economics or availability of fuel (*i.e.*, seasonal considerations). As stated elsewhere in this preamble, EPA considers a unit to be an oil-fired unit if (1) it is equipped to fire oil and/or natural gas, and (2) it fires oil in amounts greater than or equal to two percent of its annual fuel consumption. This two percent value is intended to represent that amount of oil that a true natural gas-fired unit might use strictly for start-up purposes on an annual basis. The EPA solicits comment on whether this two percent breakpoint is a reasonable basis for allowing those units that use oil only for startup purposes to be exempted from regulation under the proposed rule.

V. Impacts of the Proposed Rule

Under the section 111 proposed approach, Hg reductions prior to 2015 are expected to be comparable to Hg reductions achieved under the proposed section 112 MACT. In fact, given the early reductions achieved from banking under the section 111 proposal, plus the possibility that a section 112 MACT approach provides no incentive for power plants to reduce below the required level, a section 111 approach will likely lead to greater reductions in the Hg relative to the proposed section 112 MACT approach. After 2015, the Phase II cap in the proposed section 111 approach is reduced to 15 tpy, leading to still more reductions than achieved under the proposed section 112 MACT. Therefore, the estimated benefits of the proposed section 112 MACT can serve as a lower bound of the benefits achieved through the proposed section 111 approach.

A. What Are the Air Impacts?

When the emissions rates developed in today's proposed section 112 MACT rule are applied to current coal use (based on the ICR), annual Hg emissions to the atmosphere from Utility Units are projected to be 34 tons. Consistent with previous regulatory programs affecting electricity generating units, EPA has analyzed this scenario using the Integrated Planning Model (IPM) (*see http://www.epa.gov/airmarkets/epa-ipm*). Based on this model, total Hg emissions from affected coal-fired power plants are projected to be 30 tons in 2010 and 31 tons in 2020. However, Hg emissions are likely to be much closer to the calculated level of 34 tons. First, the model allows for Hg reductions using ACI only at the 60 percent and 90 percent levels (rather than using a range of 60 to 90 percent), which may lead the model to understate Hg emissions from as much as 2.3 tons by bituminous-fired units. Second, the modeling may not fully capture the range of Hg in different coal ranks which could underestimate emissions, particularly when modeling a facility-specific limit as is the case with this analysis. The modeling assumes a range of Hg contents for different ranks of coal, but due to averaging, may not fully capture all Hg contents of coal. (*See* IPM documentation, Chapter 4 for further information on Hg content of coal.)

B. What Are the Water and Solid Waste Impacts?

The EPA estimated the additional water usage that would result from the MACT floor level of control to be 307 million gallons per year for existing affected sources. These costs are accounted for in the control costs estimates.

The EPA estimated the additional solid waste that would result from the MACT floor level of control to be 282,000 tpy for existing sources. The costs of handling the additional solid waste generated are also accounted for in the control costs estimates.

A discussion of the methodology used to estimate impacts is presented in the memorandum entitled "Methodology for Estimating Cost and Emissions Impact for Coal- and Oil-Fired Electric Utility Steam Generating Units National Emission Standards for Hazardous Air Pollutants" in the docket.

C. What Are the Energy Impacts?

The EPA expects an increase of approximately 1,418 million kilowatt hours (kWh) in national annual energy usage as a result of the proposed rule. The increase results from the electricity required by existing sources to operate control devices installed to meet the proposed rule.

D. What Are the Control Costs?

Table 6 of this preamble shows the estimated capital and annual cost impacts for each subcategory. Costs include testing and monitoring costs, but not record keeping and reporting costs.

TABLE 6.—SUMMARY OF CAPITAL AND ANNUAL COSTS FOR NEW AND EXISTING SOURCES UNDER THE SECTION 112 MACT PROPOSAL

Source	Subcategory	Estimated/projected No. of affected units	Annualized cost (10^6\$/yr)	Capital costs (10^6\$)
Coal-fired Units	Bituminous-fired	549	728	4,609
	Subbituminous-fired	68	92	607
	Lignite-fired	5	9	61
	Blends	74	101	654
	IGCC unit	0	0	0
	Coal refuse-fired	3	16	52
Total, coal-fired units		719	945	5,982
Oil-fired Units	Oil-fired	186	417	2,190
Total, coal- and oil-fired units		905	1,362	8,172

Costs are estimated from methods based on the "EPA Air Pollution Control Cost Manual," which uses a factor method for estimating total capital investment, then total annual and annualized costs for an emission control system. Basic equipment costs are found either from the Manual or from vendor contacts. Factors in the manual are applied to the equipment cost to estimate direct and indirect costs associated with installing the equipment. Annual operating and maintenance costs and annualized costs for debt service are estimated to obtain annual payments attributable to the system used for emission control. For electric utility costing, each of the U.S. units is costed separately using equations developed from the cost manual. A discussion of the methodology used to estimate impacts is presented in the memorandum entitled "Methodology for Estimating Cost and Emissions Impact for Coal- and Oil-Fired Electric Utility Steam Generating Units National Emission Standards for Hazardous Air Pollutants" in the docket.

As part of the costing, annual quantities of water, wastewater, solid waste, and energy required for operating the emission control systems are determined. These quantities represent materials or energy used in the system or wastes that must be treated as a result of system operation. The quantities are listed elsewhere in this preamble.

E. Can We Achieve the Goals of the Proposed Section 112 MACT Rule in a Less Costly Manner?

The EPA has tried in developing the section 112 MACT proposal to ensure that the cost to the regulated community is reasonable in view of the potential benefits, and to allow maximum flexibility in compliance options consistent with our statutory obligations. The Agency recognizes, however, that the section 112 MACT proposal may still require some facilities to take costly steps to further control Hg and Ni emissions even though those emissions may not result in exposures which could pose unacceptable risk. The EPA is, therefore, specifically soliciting comment on whether there are further ways to structure the section 112 MACT proposal to focus on the facilities which may pose significant risks to public health and avoid the imposition of high costs on facilities that pose little risk to public health and the environment.

F. What Are the Social Costs and Benefits of the Proposed Section 112 MACT Rule?

The proposed rule sets out two major alternative actions. The first alternative would regulate Hg emissions under the section 112 MACT provisions CAA. The second alternative would regulate Hg emissions through a cap-and-trade program under section 111 of the CAA. Implementation of the section 111 cap-and-trade program would be carried out in coordination with a cap-and-trade program for SO_2 and NO_X emissions under the IAQR, which is also being proposed in today's **Federal Register.** The IAQR would limit Utility Unit SO_2 and NO_X emissions in approximately 30 eastern states to address their contribution to nonattainment of the fine particle ($PM_{2.5}$) and ozone National Ambient Air Quality Standards (NAAQS).

The control approaches adopted by Utility Units in response to the proposed section 112 Hg MACT regulations would also achieve collateral reductions of NO_X and SO_2. Based on the scenario analyzed, the proposed action would reduce approximately 902,000 tons of NO_X emissions, and 591,000 tons of SO_2 emissions in 2010. The proposed IAQR would require annual SO_2 emissions reductions of 3.6 million tons and NO_X emissions reductions of 1.4 million tons in 2010, while achieving Hg reductions comparable to those estimated for the proposed section 112 MACT by 2010.

Our assessment of costs and benefits of the proposed MACT rule is detailed in the "Benefits Analysis for the Section 112 Utility Rule," located in the Docket. These analyses are based on the costs and emissions reductions associated with a particular Hg control scenario that is consistent with the reduction in nationwide Hg emissions expected by implementation of the proposed section 112 MACT standard. The specific emissions control scenario is derived from application of the Integrated Planning Model (IPM), which EPA has used to assess the costs and emissions reductions associated with a number of regulations of the power sector. While the Hg reduction estimates in the scenario are consistent with the Agency's assessment of control technologies, EPA is aware that estimates of associated reductions in other pollutants, notably SO_2 and NO_X (co-benefits) may vary significantly with alternative assumptions about the application of particular control technologies and incentives created by the existence of other major regulatory programs affecting the power sector. In particular, based on past EPA analyses of multi-pollutant strategies (*e.g.* Clear Skies Technical Support Document D, *http://www.epa.gov/clearskies/technical.html)* the control choices made pursuant to either a 111-or 112-based Hg program would likely be significantly affected by the requirements of the IAQR. For these reasons, in addition to the findings of the analyses derived from the MACT-only scenario, we also provide some estimates of the direction of costs and benefits under reasonably foreseeable alternative scenarios for implementing limits on Hg emissions that take such potential interactions into account.

The proposed section 111 and 112 actions address Hg and Ni emissions from coal- and oil-fired Utility Units. Exposure to emissions of Hg at low levels may cause neurological damage and learning disorders. Nickel subsulfide and refinery dusts are classified as known human carcinogens; Ni carbonyl is classified as a probable human carcinogen based upon studies in animals. Due to the control technologies selected for analysis, the actions to reduce Hg will also achieve reductions of NO_X and SO_2. Although not incorporated into the analyses, the actions to reduce Ni will also reduce direct emissions of particulate matter. Known health and welfare effects associated with the pollutants affected by the proposed rule are listed in Table 7 of this preamble. As indicated in the table, we are able to quantify and monetize only a portion of these effects.

TABLE 7.—HEALTH AND WELFARE EFFECTS OF POLLUTANTS AFFECTED BY THE PROPOSED UTILITY MACT STANDARD

Pollutant/effect	Quantified and monetized	Unquantified effects
PM/Health	Premature mortality—adults Premature mortality—infants Bronchitis—chronic and acute Hospital admissions—respiratory and cardiovascular Emergency room visits for asthma Non-fatal heart attacks (myocardial infarction) Lower and upper respiratory illness Asthma exacerbations Minor restricted activity days Work loss days	Low birth weight. Changes in pulmonary function. Chronic respiratory diseases other than chronic bronchitis. Morphological changes. Altered host defense mechanisms. Non-asthma respiratory emergency room visits. Changes in cardiac function (*e.g.,* heart rate variability). Allergic responses (to diesel exhaust).
PM/Welfare		Visibility in Class I areas. Visibility in residential and non-Class I areas. Household soiling.
Ozone/Health		Increased airway responsiveness to stimuli. Inflammation in the lung. Chronic respiratory damage. Premature aging of the lungs.

TABLE 7.—HEALTH AND WELFARE EFFECTS OF POLLUTANTS AFFECTED BY THE PROPOSED UTILITY MACT STANDARD—Continued

Pollutant/effect	Quantified and monetized	Unquantified effects
		Acute inflammation and respiratory cell damage. Increased susceptibility to respiratory infection. Non-asthma respiratory emergency room visits. Hospital admissions—respiratory. Emergency room visits for asthma. Minor restricted activity days. School loss days. Asthma attacks. Cardiovascular emergency room visits. Premature mortality B acute exposures. Acute respiratory symptoms.
Ozone/Welfare		Decreased commercial forest productivity. Decreased yields for fruits and vegetables. Decreased yields for commercial and non-commercial crops. Damage to urban ornamental plants. Impacts on recreational demand from damaged forest aesthetics. Damage to ecosystem functions. Decreased outdoor worker productivity.
Nitrogen and Sulfate Deposition/Welfare.		Costs of nitrogen controls to reduce eutrophication in selected eastern estuaries. Impacts of acidic sulfate and nitrate deposition on commercial forests. Impacts of acidic deposition on commercial freshwater fishing. Impacts of acidic deposition on recreation in terrestrial ecosystems. Impacts of nitrogen deposition on commercial fishing, agriculture, and forests. Impacts of nitrogen deposition on recreation in estuarine ecosystems. Reduced existence values for currently healthy ecosystems.
SO_2/Health		Hospital admissions for respiratory and cardiac diseases. Respiratory symptoms in asthmatics.
NO_X/Health		Lung irritation. Lowered resistance to respiratory infection. Hospital Admissions for respiratory and cardiac diseases.
Hg Health		Neurological disorders. Learning disabilities. Developmental delays. Cardiovascular effects*. Altered blood pressure regulation*. Increased heart rate variability*. Myocardial infarctions*. Reproductive effects in adults*.
Hg Deposition Welfare		Impacts on birds and mammals (*e.g.* reproductive effects). Impacts to commercial, subsistence, and recreational fishing. Reduced existence values for currently healthy ecosystems.
Ni Health		Dermatitis. Respiratory effects. Increased Risk of Lung and Nasal cancer.

* These are potential effects as the literature is either contradictory or incomplete.

It is estimated that the section 112 MACT proposal will reduce national Hg emissions to approximately 34 tons and national Ni emissions to approximately 103 tons at electric utility facilities that generate steam using fossil fuels (*i.e.*, coal or oil fuels). The health effects associated with these pollutants are discussed earlier in this preamble, however, a summary of the potential benefits is provided below. While it is beneficial to society to reduce Hg and Ni, we are unable to quantify and provide a monetized estimate of the benefits at this time due to gaps in available information on the fate of emissions for these two pollutants, human exposure, and health impact models.

The Hg and Ni emissions reductions associated with implementing of the proposed action would produce a variety of benefits. Mercury emitted from utilities and other natural and man-made sources is carried by winds through the air and eventually is deposited to water and land. In water, Hg is transformed to methylmercury through biological processes. Methylmercury, a highly toxic form of Hg, is the form of Hg of greatest concern for the purpose of this rulemaking. Once Hg has been transformed into methylmercury, it can be ingested by the lower trophic level organisms where it can bioaccumulate in fish tissue (*i.e.*, concentrations in predatory fish build up over the fish's entire lifetime, accumulating in the fish tissue as predatory fish consume other species in the food chain). Thus, fish and wildlife at the top of the food chain can have Hg concentrations that are higher than the lower species, and they can have concentrations of Hg that are higher than the concentration found in the water body itself. Therefore, the most common form of exposure to Hg for humans and wildlife is through the consumption of contaminated predatory fish, such as: Commercially consumed tuna, shark, or other saltwater fish species and recreationally caught bass, perch, walleye or other freshwater fish species. When humans consume fish contaminated with methylmercury, the ingested methylmercury is almost completely absorbed into the blood and distributed to all tissues (including the brain); it also readily passes through the placenta to the fetus and fetal brain.

Based on the findings of the National Research Council, EPA has concluded that benefits of Hg reductions would be most apparent at the human consumption stage, as consumption of fish is the major source of exposure to methylmercury. At lower levels, documented Hg exposure effects may include more subtle, yet potentially important, neurodevelopmental effects.

Some subpopulations in the U.S., such as: Native Americans, Southeast Asian Americans, and lower income subsistence fishers, may rely on fish as a primary source of nutrition and/or for cultural practices. Therefore, they consume larger amounts of fish than the general population and may be at a greater risk to the adverse health effects from Hg due to increased exposure. In pregnant women, methylmercury can be passed on to the developing fetus, and at sufficient exposure may lead to a number of neurological disorders in children. Thus, children who are exposed to low concentrations of methylmercury prenatally may be at increased risk of poor performance on neurobehavioral tests, such as those measuring attention, fine motor function, language skills, visual-spatial abilities (like drawing), and verbal memory. The effects from prenatal exposure can occur even at doses that do not result in effects in the mother. Mercury may also affect young children who consume fish contaminated with Hg. Consumption by children may lead to neurological disorders and developmental problems, which may lead to later economic consequences.

In response to potential risks of consuming fish containing elevated concentrations of Hg, EPA and FDA have issued fish consumption advisories which provide recommended limits on consumption of certain fish species for different populations. The EPA and FDA are currently developing a joint advisory that has been released in draft form. This newest draft FDA-EPA fish advisory recommends that women and young children reduce the risks of Hg consumption in their diet by moderating their fish consumption, diversifying the types of fish they consume, and by checking any local advisories that may exist for local rivers and streams. This collaborative FDA-EPA effort will greatly assist in educating the most susceptible populations. Additionally, the reductions of Hg from this regulation may potentially lead to fewer fish consumption advisories, which will benefit the fishing community.

Reducing emissions of Ni can also contribute to several benefits. We are concerned with the inhalation risks of Ni as the primary route of human exposure in this rulemaking. Nickel is found in ambient air at very low levels as a result of releases from oil combustion. The differing forms of Ni have varying levels of toxicity. There is great uncertainty about the type of Ni emitted. Respiratory effects have also been reported in humans who have been occupationally exposed to high levels of Ni. Human and animal studies have reported an increased risk of lung and nasal cancers from exposure to Ni refinery dusts and Ni subsulfide. Animal studies of soluble Ni compounds (*i.e.*, Ni carbonyl) have reported lung tumors. The EPA has classified Ni refinery subsulfide as a Group A carcinogen due to lung and nasal cancers in humans occupationally exposed to Ni refinery dust. Ni carbonyl is classified as a Group B2, probable human carcinogen based upon studies conducted in animals.

The proposed actions would also reduce NO_X and SO_2 emissions that contribute to the formation of fine particles ($PM_{2.5}$). In general, exposure to high concentrations of $PM_{2.5}$ may aggravate existing respiratory and cardiovascular disease including asthma, bronchitis and emphysema, especially in children and the elderly. Nitrogen oxides and SO_2 are also contributors to acid deposition, or acid rain, which causes acidification of lakes and streams and can damage trees, crops, historic buildings and statues. Exposure to $PM_{2.5}$ can lead to decreased lung function, and alterations in lung tissue and structure and in respiratory tract defense mechanisms which may then lead to, increased respiratory symptoms and disease, or in more severe cases, premature death or increased hospital admissions and emergency room visits. Children, the elderly, and people with cardiopulmonary disease, such as asthma, are most at risk from these health effects. Fine PM can also form a haze that reduces the visibility of scenic areas, can cause acidification of water bodies, and have other impacts on soil, plants, and materials.

As previously stated, the control technologies selected for analysis of the Hg portion of this action would also achieve reductions of NO_X and SO_2. Based on the scenario analyzed, the proposed section 112 MACT action would reduce approximately 902,000 tons of NO_X emissions, and 591,000 tons of SO_2 emissions. These projected reductions are due to the reliance on some SO_2 and NO_X controls and coal-switching to achieve Hg reductions. When compared to the base case, there is a projected shift towards lower sulfur bituminous coals (about 6 percent) that are also lower in Hg, which results in SO_2 emissions reductions. In addition, some units are projected to use SO_2 controls (scrubbers) to comply with the proposed section 112 MACT (about 1 GW), as well as generation shifts (about 1 percent) from uncontrolled units to units with scrubbers which would result in additional SO_2 reductions from the base case. Projected NO_X emissions reductions from the base case are a result of seasonal NO_X controls being operated annually in the MACT case to achieve additional Hg control (about 90 GW of SCR operate annually). Because NO_X and SO_2 contribute to the formation of $PM_{2.5}$, and because direct PM controls would be applied to meet the Ni requirements, these standards should lead to substantial benefits from reductions of ambient PM. Therefore, reduction of SO_2 and NO_X emissions from utilities will contribute to reduced human health and welfare impacts.

Due to both technical and resource limits in available modeling, we have only been able to quantify and monetize the benefits for a few of the endpoints associated with reducing Hg, Ni, directly emitted PM, and gaseous NO_X

and SO_2. However, based on relevant available modeling of several alternative control strategies to reduce Utility Unit SO_2 and NO_X emissions (including Clear Skies), we can approximate the benefits of reduced exposure to ambient PM resulting from reductions in precursor emissions of NO_X and SO_2. These benefit categories—including reductions in premature mortality—are believed to represent a dominant fraction of the total benefits associated with these proposed actions.

To quantify benefits, we evaluated PM-related health effects (including SO_2 and NO_X contributions to ambient concentrations of $PM_{2.5}$). Our approach requires the estimation of changes in air quality expected from the rule and the resulting effects on health. In order to characterize the benefits of today's proposed section 112 action, given the constraints on time and resources available for the analysis, we adopted a benefits transfer technique that relies on air quality and benefits modeling conducted for the recently proposed Clear Skies Act of 2003. Results from the Clear Skies analysis in 2010 are then scaled and transferred to the emission reductions expected from the proposed section 112 MACT rule.

This benefits assessment is conducted in two phases. First, using modeling runs developed in support of the Clear Skies legislation, we estimated the number of reduced incidences of illnesses, hospitalizations, and premature fatalities associated with a unit change in ambient concentrations of $PM_{2.5}$. The Clear Skies program covers a similar universe of affected sources and yields larger reductions in NO_X and SO_2 emissions. The distribution of emission reductions across states differs between the two analyses, especially in the Western U.S. Given the very small reductions in NO_X and SO_2 expected to occur in the Western U.S. as a result of the rule and the potential for errors in transferring benefits, we limit the benefits analysis to the Eastern U.S., and derive the benefits transfer factors from the Eastern U.S. Clear Skies benefits results only. Recognizing the differences in emission reduction patterns in the Eastern U.S. between the Clear Skies analysis and the current proposed MACT standards, we believe that the benefits per ton of SO_2 and NO_X estimated for the Clear Skies analysis represents a reasonable approximation of the benefits per ton that might be realized from the reductions in NO_X and SO_2 expected under the current proposed section 112 rule. The analysis of the proposed section 112 MACT includes only health benefits related to $PM_{2.5}$ reductions associated with the NO_X and SO_2 reductions, and does not include health benefits related to ozone reductions, visibility benefits, and other benefits including reduced nitrogen deposition and acidification. For the most part, quantifiable ozone benefits do not contribute significantly to the monetized benefits: thus, their omission does not materially affect the magnitude of estimated benefits. Visibility benefits may be more significant; although, visibility has generally contributed only a few percent of total monetized benefits.

Second, we used the Clear Skies analysis to develop a relationship between changes in ambient $PM_{2.5}$ concentrations and the underlying NO_X and SO_2 emission reductions to reflect differences in emissions reductions between the modeled Clear Skies scenario and the proposed standard. The sum of the scaled benefits for the SO_2 and NO_X emission reductions provide us with the total benefits of the rule.

The benefit estimates derived from the Clear Skies air quality modeling in the first phase of our analysis uses an analytical structure and sequence similar to that used in the benefits analyses for the proposed Nonroad Diesel rule and proposed IAQR and in the "section 812 studies" analysis of the total benefits and costs of the Clean Air Act. We used many of the same models and assumptions used in the Nonroad Diesel and IAQR analyses as well as other Regulatory Impact Analyses (RIAs) prepared by the Office of Air and Radiation. By adopting the major design elements, models, and assumptions developed for the section 812 studies and other RIAs, we have largely relied on methods which have already received extensive review by the independent Science Advisory Board (SAB), the National Academies of Sciences, by the public, and by other federal agencies. Interested parties will be able to obtain further information from the section 812 study on the kinds of methods we are likely to use for estimating benefits and costs in the final rule.

The benefits transfer method used in the second phase of the analysis is similar to that used to estimate benefits in the recent analysis of the proposed Nonroad Diesel rule and Nonroad Large Spark-Ignition Engines and Recreational Engines standards (67 FR 68241, November 8, 2002). A similar method has also been used in recent benefits analyses for the proposed Industrial Boilers and Process Heaters NESHAP and the Reciprocating Internal Combustion Engines NESHAP.

The economic and energy impact analysis memo (for the proposed section 112 MACT) details the control scenario as consisting of a combination of direct Hg controls and additional SO_2 and NO_X controls. Under this scenario, the extent of SO_2 and NO_X controls in Eastern U.S. would be limited to approximately 902,000 tons of NO_X and 591,000 tons of SO_2. As outlined above, these reductions drive the monetized benefits of the proposed rule, which would be approximately $15 billion (1999$). This economic benefit is associated with approximately 2,200 avoided premature mortalities, 1,200 avoided cases of chronic bronchitis, 2,900 avoided non-fatal heart attacks, thousands of avoided hospital and emergency room visits for respiratory and cardiovascular diseases, tens of thousands of avoided days with respiratory symptoms, and millions of avoided work loss and restricted activity days. The EPA recognizes that at the present time, these direct controls have not been adequately demonstrated, so this scenario reflects uncertain but possible advances in the availability of such controls. Under a more restrictive assumption about the availability of direct Hg controls (*e.g.*, ACI) than used in this analysis, Utility Unit control strategies may rely to an even greater extent on SO_2, NO_X, and direct PM control approaches to reduce Hg. In such an alternative MACT-only scenario, projected costs and benefits would be correspondingly much greater than those indicated in Table 8 of this preamble.

As noted above, however, consideration of the proposed section 112 MACT or proposed section 111 only scenarios does not capture the full dimension of the most likely air regulatory situation facing the power industry over the next decade. As noted above, EPA is also proposing significant additional SO_2 and NO_X reduction requirements to limit interstate transport of these pollutants. These requirements are likely to require Utility Units to install SO_2 and NO_X controls on significant fractions of their coal-fired capacity. For these reasons, there are strong public policy reasons to consider the combined influence of the Hg and IAQR requirements.

Table 8 of this preamble summarizes the results of the benefit-cost analysis of the proposed section 112 MACT scenario and compares them with estimates of the range of potential costs and benefits associated with an alternative scenario that addresses combined implementation of section 111 Hg requirements in coordination with proposed SO_2 and NO_X

requirements in the proposed IAQR. The potential influence of such a combined scenario is illustrated in the second column of Table 8 of this preamble, which assumes the proposed section 111 requirements are implemented in combination with the IAQR. The IAQR analysis projects that the Hg reductions associated with implementing the SO_2/NO_X requirements in the Eastern U.S. in 2010 would be approximately 10.6 tons per year, which is almost identical to those estimated from the proposed section 112 MACT-only scenario.

If the goal for the proposed section 111 program in 2010 is limited to these co-control reductions, there might be no additional costs or benefits to the program, over those achieved by the IAQR—this is indicated in the lower portion of the ranges in Table 8 of this preamble. By contrast, if the proposed section 111 regulation adopts a 2010 goal similar to the Phase I Clear Skies Hg cap, additional Hg reductions would be required over those forecast for the IAQR. Based on a multipollutant analyses conducted for Clear Skies (p D–9, Technical appendix D, at *http://www.epa.gov/airmarkets/epa-ipm*), power generators would likely opt for some additional SO_2 and NO_X controls beyond those needed for the IAQR, as well as considering additional direct Hg controls. Although the actual results are uncertain, the Clear Skies results suggest that the costs and benefits associated with a section 112 MACT-only approach may reflect a reasonable lower bound for the additional costs and benefits. These potential additional costs and benefits related to additional Hg controls are reflected in the upper end of the ranges in Table 8 of this preamble. In the decade beyond 2010, the proposed section 111 program would establish a 15 ton cap for Hg in 2018, similar to Clear Skies. Based on Clear Skies analyses, this would result in further Hg controls, which would likely include at least some additional SO_2/NO_X controls as well as direct Hg controls. The IAQR program alone produces only small additional reductions in Hg emissions in 2020. The Hg reductions estimated for the proposed section 112 MACT and the proposed section 111 and proposed IAQR programs are summarized in Table 9. These forecasts are based on IPM analyses of the proposed section 112 MACT scenario outlined above, the proposed IAQR analysis, and estimates derived from earlier analyses of the Clear Skies program.

Every benefit-cost analysis examining the potential effects of a change in environmental protection requirements is limited, to some extent, by data gaps, limitations in model capabilities (such as geographic coverage), and uncertainties in the underlying scientific and economic studies used to configure the benefit and cost models. Deficiencies in the scientific literature often result in the inability to estimate changes in health and environmental effects. Deficiencies in the economics literature often result in the inability to assign economic values even to those health and environmental outcomes that can be quantified. While these general uncertainties in the underlying scientific and economics literatures are discussed in detail in the RIA and its supporting documents and references, the key uncertainties which have a bearing on the results of the benefit-cost analysis of today's action are the following:

1. The exclusion of potentially significant benefit categories (*e.g.*, health and ecological benefits of reduction in hazardous air pollutants emissions);
2. Errors in measurement and projection for variables such as population growth;
3. Uncertainties in the estimation of future year emissions inventories and air quality;
4. Uncertainties associated with the extrapolation of air quality monitoring data to some unmonitored areas required to better capture the effects of the standards on the affected population;
5. Variability in the estimated relationships of health and welfare effects to changes in pollutant concentrations; and
6. Uncertainties associated with the benefit transfer approach.

Despite these uncertainties, we believe the benefit-cost analysis provides a reasonable indication of the expected economic benefits of the proposed actions under a given set of assumptions.

Based on estimated compliance costs (control + administrative costs associated with Paperwork Reduction Act requirements associated with the proposed rule and predicted changes in the price and output of electricity), the estimated social costs of the proposed section 112 MACT-only scenario are $1.6 billion (1999$). Social costs are different from compliance costs in that social costs take into account the interactions between affected producers and the consumers of affected products in response to the imposition of the compliance costs. In this action, coal-fired utilities are the affected producers and users of electricity are the consumers of the affected product.

As explained above, we estimate $15 billion in benefits from the proposed section 112 MACT, compared to less than $2 billion in costs. It is important to put the results of this analysis in the proper context. The large benefit estimate is not attributable to reducing human and environmental exposure to Hg. It arises from ancillary reductions in SO_2 and NO_X that result from controls aimed at complying with the proposed MACT. Although consideration of ancillary benefits is reasonable, we note that these benefits are not uniquely attributable to Hg regulation. Under the IAQR, coal-fired units would achieve much larger reductions in SO_2 and NO_X emissions than they would under the proposed section 112 MACT. In the years ahead, as the Agency and the States develop rules, guidance and policies to implement the new air quality standards for ozone and PM, coal-fired power plants will be required to implement additional controls to reduce SO_2 and NO_X (*e.g.*, scrubbers, SCR units, year-round NO_X controls in place of summertime only controls, conversion to low-sulfur coals, and so forth). Thus, most or all of the ancillary benefits of Hg control would be achieved anyway, regardless of whether a section 112 MACT is promulgated. Based on analysis of the Clear Skies legislation, EPA believes that the proposed 2018 Hg cap in the proposed section 111 rule would result in additional SO_2 and NO_X reductions beyond those that would be required under the proposed IAQR. Thus, the section 111 approach, unlike the section 112 approach, may achieve SO_2 and NO_X reduction benefits beyond those that would be achieved under the IAQR. We believe, however, that even if no Hg controls were imposed, most major coal-fired units would still have to reduce their SO_2 and NO_X emissions as part of the efforts to bring the nation into attainment with the new air quality standards. In light of these considerations, the Agency believes that the key rationale for controlling Hg is to reduce public and environmental exposure to Hg, thereby reducing risk to public health and wildlife. Although the available science does not support quantification of these benefits at this time, the Agency believes the qualitative benefits are large enough to justify substantial investment in Hg emission reductions.

It should be recognized, however, that this analysis does not account for many of the potential benefits that may result from these actions. The net benefits would be greater if all the benefits of the Hg, Ni, and other pollutant reductions could be quantified. Notable omissions to the net benefits include all benefits of HAP reductions, including reduced cancer incidences, toxic morbidity effects, and cardiovascular and CNS effects, and all health and welfare effects from reduction of ambient NO_X and SO_2.

TABLE 8.—SUMMARY OF MONETIZED BENEFITS, COSTS, AND NET BENEFITS OF THE PROPOSED SECTION 112 MACT STANDARD, [1] WITH A RANGE FOR POTENTIAL ALTERNATIVE SCENARIO ESTIMATES FOR MACT AND SECTION III PROPOSAL IN 2010 ($BILLIONS/YR)

	MACT-only Scenario	Sec. 111 plus IAQR Combined[4]
Social Costs[2]	$1.6	$2.9 to 4.5+
Social Benefits[3]:		
PM-related Health benefits	$15+B	$58 to 73+B
Net Benefits (Benefits – Costs)[3]	$13+B	$55 to $68+B

[1] All costs and benefits are rounded to two significant digits.
[2] Note that costs are the total costs of reducing all pollutants, including Hg and other metallic air toxics, as well as NO_X and SO_2 reductions. Benefits in this table are associated only with NO_X and SO_2.
[3] Not all possible benefits or disbenefits are quantified and monetized in this analysis. In particular, ozone health and welfare and PM welfare benefits are omitted. Other potential benefit categories that have not been quantified and monetized are listed in Table 5. B is the sum of all unquantified benefits and disbenefits.
[4] Estimated combined benefits of S. 111 plus IAQR costs and benefits in 2010. Ranges do not reflect actual analyses of combined programs. Rough estimates based on consideration of available IAQR, MACT, and Clear Skies analyses. See text.

TABLE 9.—FORECAST MERCURY EMISSIONS UNDER THE PROPOSED SECTION 112 MACT, AND THE PROPOSED SECTION 111 RULE AND THE PROPOSED IAQR[1]

Program/Year	2010	2020
MACT only	34	31
IAQR only	34	30
IAQR and section 111 caps	(2)	18–22

[1] Annual reductions from base case forecast under current programs to reduce Utility Unit emissions. MACT only value for 2015 based on interpolation of 2010 and 2015. Lower bound of IAQR and section 111 caps in 2010 assumes Hg cap is set at co-control level achieved by IAQR. Upper bound in 2010 and ranges thereafter estimates derived from Clear Skies analyses.
[2] Mercury emissions will reflect the level of emissions resulting from the co-benefits of controlling SO_2 and NO_X. See section IV.B.1 for a detailed discussion.

VI. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), EPA must determine whether a regulatory action is "significant" and, therefore, subject to review by the Office of Management and Budget (OMB) and subject to the requirements of the Executive Order. The Executive Order defines "significant regulatory action" as one that is likely to result in a rule that may:

(1) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities;

(2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;

(3) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs, or the rights and obligation of recipients thereof; or

(4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

Pursuant to the terms of Executive Order 12866, it has been determined that the proposed rule is an economically "significant regulatory action" because the annual cost may exceed $100 million dollars. As such, this action was submitted to OMB for review. Changes made in response to OMB suggestions or recommendations will be documented in the public record.

B. Paperwork Reduction Act

The information collection requirements in the proposed NESHAP have been submitted for approval to OMB under the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* The ICR document prepared by EPA has been assigned EPA ICR No.____.

The information requirements are based on notification, recordkeeping, and reporting requirements in the NESHAP General Provisions (40 CFR part 63, subpart A), which are mandatory for all operators subject to national emission standards. These recordkeeping and reporting requirements are specifically authorized by section 114 of the Act (42 U.S.C. 7414). All information submitted to EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B.

The proposed rule would require a monitoring plan submitted to the Administrator but would not require any reports beyond those required by the General Provisions. The recordkeeping requirements require only the specific information needed to determine compliance. The proposed rule would require notification in advance of complying with the rule by changing fuel.

The annual average monitoring, reporting, and recordkeeping burden for this collection (averaged over the first 3 years of this ICR) is estimated to total 243,000 labor hours per year. This includes 2 responses per year from 568 respondents for an average of 214 hours per response. The total annualized cost burden is estimated at $48.4 million, including labor, capital, and operation and maintenance. The capital costs of monitoring equipment are estimated at $66.8 million; the estimated annual cost for operation and maintenance of monitoring equipment is $15.4 million.

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; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR part 63 are listed in 40 CFR part 9.

To comment on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques, EPA has established a public docket for this proposed rule, which includes this ICR, under Docket ID number OAR–2003–0056. Submit any comments related to the ICR for this proposed rule to EPA and OMB. See the **ADDRESSES** section at the beginning of this notice for where to submit comments to EPA. Send comments to OMB at the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW, Washington, DC 20503, Attention: Desk Office for EPA. Because OMB is required to make a decision concerning the ICR between 30 and 60 days after January 30, 2004, a comment to OMB is best assured of having its full effect if OMB receives it by March 1, 2004. The final rule will respond to any OMB or public comments on the information collection requirements contained in this proposal.

C. Regulatory Flexibility Act

The EPA has determined that it is not necessary to prepare a regulatory flexibility analysis in connection with the proposed rule. We have also determined that the proposed rule will not have a significant impact on a substantial number of small entities.

For purposes of assessing the impacts of the final rule on small entities, small entity is defined as:

(1) A small business according to Small Business Administration size standards by the North American Industry Classification System (NAICS) category of the owning entity. For electric utilities, the size standard is 4 billion kilowatt-hours of production or less, respectively;

(2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and

(3) a small organization that is any not-for-profit enterprise that is independently owned and operated and is not dominant in its field.

After considering the economic impact of the proposed rule on small entities, we have determined that the proposed rule will not have a significant impact on a substantial number of small entities. Companies owning affected facilities as small businesses are projected to incur about 1.2 percent of the total compliance costs. Comparing these costs for small entities to their generation revenues, they represent about 1.3 percent of generation revenues.

An economic impact analysis was performed to estimate the changes in product price and production quantities for this action. As mentioned in the summary of economic impacts earlier in this preamble, the estimated changes in prices and output for affected firms is less than 1 percent.

This analysis, therefore, allows us to certify that there will not be a significant impact on a substantial number of small entities from the implementation of the proposed rule. For more information, consult the docket for the proposed rule.

We specifically solicit comment on the option to lower small entity costs through excluding units that release small amounts of Hg (*e.g.*, less than 25 pounds annually) from the phase II cap, while maintaining this cap for the largest sources of Hg.

We continue to be interested in the potential impacts of the proposed rule on small entities and welcome comments on issues related to such impacts.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, we generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that may result in expenditures to State, local, and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any 1 year. Before promulgating a rule for which a written statement is needed, section 205 of the UMRA generally requires us to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows us to adopt an alternative other than the least costly, most cost-effective or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before we establish any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, we must develop a small government agency plan under section 203 of the UMRA. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

We have determined that the proposed rule contains a Federal mandate that may result in expenditures of $100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any 1 year. Accordingly, we have prepared a written statement (titled "Unfunded Mandates Reform Act Analysis for the Proposed Industrial Boilers and Process Heaters NESHAP)" under section 202 of the UMRA which is summarized below.

1. Statutory Authority

As discussed in section I of this preamble, the statutory authority for the proposed rulemaking is sections 111 and 112 of the CAA. Title III of the CAA Amendments was enacted to reduce nationwide air toxic emissions. Section 112(b) of the CAA lists the 188 chemicals, compounds, or groups of chemicals deemed by Congress to be HAP. These toxic air pollutants are to be regulated by NESHAP.

Section 112(d) of the CAA directs us to develop NESHAP which require existing and new major sources to control emissions of HAP using MACT based standards. This NESHAP applies to all fossil fuel-fired utility boilers located at major sources of HAP emissions as mentioned earlier in this preamble.

In compliance with section 205(a) of the UMRA, we identified and considered a reasonable number of regulatory alternatives. Additional information on the costs and environmental impacts of these regulatory alternatives is presented in the docket.

The regulatory alternative upon which the proposed rule is based represents the MACT floor for fossil fuel-fired utility boilers and, as a result, it is the least costly and least burdensome alternative.

2. Social Costs and Benefits

The benefits and cost analyses prepared for the proposed rule are detailed in the "Benefit Analysis of the CAA Section 111 Proposal To Reduce Mercury Emissions From Fossil-Fuel Fired Utilities" and the "Economic and Energy Impact Analysis of the Section 112 Utility MACT," respectively. Both of these reports are in the docket. Based on estimated compliance costs associated with the proposed rule and the predicted change in prices and production in the affected industry, the estimated social costs of the proposed rule are $1.6 billion (1999 dollars).

It is estimated that by 2010, Hg emissions will be reduced by the section 112 MACT rule to approximately 34 tons and Ni emissions reduced to approximately 103 tons. Studies have determined a relationship between exposure to these HAP and the onset of cancer and a number of other health effects. The Agency is unable to provide a monetized estimate of the benefits of the Hg and Ni emissions reduced by the proposed rule at this time. However, there are significant reductions in NO_X and SO_2 that occur. Reductions of NO_X amount to 902,000 tons and 591,000 tons of SO_2 are expected to occur. These reductions occur from existing sources in operation in 2010 and are expected to continue throughout the life of the affected sources. The major health effect that results from these NO_X and SO_2 emissions reductions is a reduction in premature mortality. Other health effects that occur are reductions in chronic bronchitis, asthma attacks, and work-lost days (*i.e.*, days when employees are unable to work).

While we are unable to monetize the benefits associated with the Hg and Ni HAP emissions reductions, we are able to monetize the benefits associated with the PM and SO_2 emissions reductions. For NO_X and SO_2, we estimated the benefits associated with reductions of health effects but were unable to quantify all categories of benefits (particularly those associated with ecosystem and environmental effects). Estimates of the benefits and costs of the SO_2 and NO_X emission reductions associated with the proposed actions are presented in Table 8 above. Unquantified benefits are noted with "B" in the estimates presented below.

3. Future and Disproportionate Costs

The Unfunded Mandates Act requires that we estimate, where accurate estimation is reasonably feasible, future compliance costs imposed by the proposed rule and any disproportionate budgetary effects. Our estimates of the future compliance costs of the proposed rule are discussed in section_of this preamble.

We do not believe that there will be any disproportionate budgetary effects of the proposed rule on any particular areas of the country, State or local governments, types of communities (*e.g.*, urban, rural), or particular industry segments. This is true for the 28 facilities owned by about 80 different government bodies, and this is borne out by the results of the "Economic and Energy Impact Analysis of the Utility MACT," the results of which are discussed in a previous section of this preamble.

4. Effects on the National Economy

The Unfunded Mandates Act requires that we estimate the effect of the proposed rule on the national economy. To the extent feasible, we must estimate the effect on productivity, economic growth, full employment, creation of productive jobs, and international competitiveness of the U.S. goods and services, if we determine that accurate estimates are reasonably feasible and that such effect is relevant and material.

The nationwide economic impact of the proposed rule is presented in the "Economic and Energy Impact Analysis for the Utility MACT" in the docket. This analysis provides estimates of the effect of the proposed rule on some of the categories mentioned above. The results of the economic impact analysis are summarized in a previous section of this preamble.

5. Consultation With Government Officials

The Unfunded Mandates Act requires that we describe the extent of the Agency's prior consultation with affected State, local, and tribal officials, summarize the officials' comments or concerns, and summarize our response to those comments or concerns. In addition, section 203 of the UMRA requires that we develop a plan for informing and advising small governments that may be significantly or uniquely impacted by a proposal. Although the proposed rule does not affect any State, local, or tribal governments, we have consulted with State and local air pollution control officials. We also have held meetings on the proposed rule with many of the stakeholders from numerous individual companies, environmental groups, consultants and vendors, labor unions, and other interested parties. We have added materials to the Air docket to document these meetings.

In addition, we have determined that the proposed rule contains no regulatory requirements that might significantly or uniquely affect small governments. While some small governments may have some sources affected by the proposed rule, the impacts are not expected to be significant. Therefore, today's proposed rule is not subject to the requirements of section 203 of the UMRA.

E. Executive Order 13132: Federalism

Executive Order 13132 (64 FR 43255, August 10, 1999), requires EPA to develop an accountable process to ensure "meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications." "Policies that have federalism implications" is defined in the Executive Order to include regulations that have "substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government."

The proposed rule does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132.

Although section 6 of Executive Order 13132 does not apply to the proposed rule, we consulted with representatives of State and local governments to enable them to provide meaningful and timely input into the development of the proposed rule. This consultation took place during the FACA committee meetings where members representing State and local governments participated in developing recommendations for this rulemaking. The concerns raised by representatives of State and local governments were considered during the development of the proposed rule.

In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicits comment on the proposed rule from State and local officials.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

Executive Order 13175 (65 FR 67249, November 6, 2000) requires the EPA to develop an accountable process to ensure "meaningful and timely input by tribal officials in the development of regulatory policies that have Tribal implications." "Policies that have tribal implications" is defined in the Executive Order to include regulations that have "substantial direct effects on one or more Indian tribes, on the relationship between the Federal government and the Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes."

Under section 5(b) of Executive Order 13175, EPA may not issue a regulation that has tribal implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by Tribal governments, or EPA consults with Tribal officials early in the process of developing the proposed regulation. Under section 5(c) of Executive Order 13175, EPA may not issue a regulation that has Tribal implications and that preempts tribal law, unless the Agency consults with Tribal officials early in the process of developing the proposed regulation.

The EPA has concluded that the proposed rule may have Tribal implications because two coal-fired Utility Units are located in Indian Country. Based on a review of information available to EPA at this time about the operations at these two plants, the Agency concluded that compliance of the plants with the requirements of the proposed rule would not impose substantial direct compliance costs on the affected Tribal governments. The EPA specifically solicits additional comment from Tribal officials on the proposed rule's potential impacts on Utility Units located in Indian Country.

G. Executive Order 13045: Protection of Children From Environmental Health and Safety Risks

Executive Order 13045, "Protection of Children From Environmental Health Risks and Safety Risks" (62 FR 19885, April 23, 1997) applies to any rule that (1) is determined to be "economically significant" as defined under Executive Order 12866, and (2) concerns an environmental health or safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, Section 5–501 of the Order directs the Agency to evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives.

In accordance with the Order, the Agency evaluated the environmental and health and safety effects of the proposed rule, and for the reasons explained above, the Agency believes that the proposed strategies are preferable to other potentially effective and reasonably feasible alternatives. The strategies proposed in this rulemaking will further improve air quality and will further improve children's health.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

Executive Order 13211 (66 FR 28355, May 22, 2001) provides that agencies shall prepare and submit to the Administrator of the Office of Information and Regulatory Affairs, Office of Management and Budget, a Statement of Energy Effects for certain actions identified as "significant energy actions." Section 4(b) of Executive Order 13211 defines "significant energy actions" as "any action by an agency (normally published in the **Federal Register**) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of final rulemaking, and notices of final rulemaking: (1) (i) That is a significant regulatory action under Executive Order 12866 or any successor order, and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) that is designated by the Administrator of the Office of Information and Regulatory Affairs as a "significant energy action." The proposed rule is a "significant energy action" because it is likely to have a significant adverse effect on the supply, distribution, or use of energy. The basis for the determination is as follows.

Compared to 2010 projections of existing statutory and regulatory requirements, coal-fired and gas-fired electricity generation are projected to remain relatively unchanged by this action. When compared to 2010 projections of existing statutory and regulatory requirements, about 900 MW of coal-fired capacity is projected to be uneconomic to maintain. Coal production for the electric power sector is expected to increase from 2000 levels, about 147 million tons or 16 percent. When compared to 2010 projections of existing statutory and regulatory requirements, the nationwide price of fuel for the electric power sector, both coal and natural gas remain relatively unchanged by this action, with coal prices projected to remain unchanged and gas prices projected to increase less than 1 percent. Nationwide retail electricity prices are projected to gradually decline from 2000 levels but then rise over time. Prices are projected to drop initially due to excess generation capacity; in 2010 prices are projected to increase due to new capacity requirements, which lead to higher capital costs and greater natural gas use, and higher retail prices passed on to consumers. In 2020, retail electricity prices are projected to still be below 2000 prices. When compared to 2010 projections of existing statutory and regulatory requirements, electricity prices are projected to increase less than 1 percent. We also expect that there will be no discernible impact on the import of foreign energy supplies, and no other adverse outcomes are expected to occur with regards to energy supplies. For more information on the estimated energy effects, please refer to the economic and energy impact analysis memo for the proposed rule. The analysis is available in the public docket. Total annual costs of this action are projected to be up to $1.6 billion in 2010, depending on other actions that EPA or States might take to control SO_2 and NO_X emissions. These costs represent about a 1.9 percent increase in annual electricity production costs.

Because this proposed regulation has greater than a 1 percent impact on the cost of electricity production and because it results in the retirement of greater than 500 MW of coal-fired generation (the retirement estimate is 900 MW), this regulation is significant. It should be noted that EPA has proposed a trading program to achieve Hg reduction as an alternative to the MACT standard, which is a command and control regulation. The relative flexibility offered by a trading program may ease the impact on energy production.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995 (Pub. L. No. 104–113; 15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory and procurement activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.*, materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The NTTAA directs EPA to provide Congress, through annual reports to the OMB, with explanations when EPA does not use available and applicable voluntary consensus standards.

This rulemaking involves technical standards.

List of Subjects

40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Coal, Electric power plants, Intergovernmental relations, Metals, Natural gas, Nitrogen dioxide, Particulate matter, Reporting and recordkeeping requirements, Sulfur oxides.

40 CFR Part 63

Environmental protection, Air pollution control, Hazardous substances, Reporting and recordkeeping requirements.

Dated: December 15, 2003.

Michael O. Leavitt,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, parts 60 and 63 of the Code of the Federal Regulations are proposed to be amended as follows:

Note: There are two options proposed for comment. Based on the comments we receive on this proposal, we will promulgate either Option 1 or Option 2.

Option 1—Proposed Amendments to Parts 60 and 63

PART 60—[AMENDED]

1. The authority citation for part 60 continues to read as follows:

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

2. Section 60.17 is amended by adding paragraph (a)(65) to read as follows:

§ 60.17 Incorporations by Reference.

* * * * *

(a) * * *

(65) ASTM D6784–02, Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), for appendix B to part 60, Performance Specification 12A.

* * * * *

APPENDIX B PART 60

3. Appendix B to part 60 is amended by adding in numerical order new Performance Specification 12A to read as follows:

Performance Specification 12a—Specifications and Test Procedures for Total Vapor Phase Mercury Continuous Emission Monitoring Systems in Stationary Sources

1.0 Scope and Application.

1.1 Analyte.

Analyte	CAS No.
Mercury (Hg)	7439–97–6

1.2 Applicability.

1.2.1 This specification is for evaluating the acceptability of total vapor phase Hg continuous emission monitoring systems (CEMS) installed on the exit gases from fossil fuel fired boilers at the time of or soon after installation and whenever specified in the regulations. The Hg CEMS must be capable of measuring the total concentration in $\mu g/m^3$ (regardless of speciation) of vapor phase Hg, and recording that concentration on a dry basis, corrected to 20 degrees C and 7 percent CO_2. Particle bound Hg is not included. The CEMS must include (a) a diluent (CO_2) monitor, which must meet Performance Specification 3 in 40 CFR part 60, appendix B, and (b) an automatic sampling system. Existing diluent and flow monitoring equipment can be used.

This specification is not designed to evaluate an installed CEMS's performance over an extended period of time nor does it identify specific calibration techniques and auxiliary procedures to assess the CEMS's performance. The source owner or operator, however, is responsible to calibrate, maintain, and operate the CEMS properly. The Administrator may require, under CAA section 114, the operator to conduct CEMS performance evaluations at other times besides the initial test to evaluate the CEMS performance. See 40 CFR 60.13(c).

2.0 Summary of Performance Specification

Procedures for measuring CEMS relative accuracy, measurement error and drift are outlined. CEMS installation and measurement location specifications, and data reduction procedures are included. Conformance of the CEMS with the Performance Specification is determined.

3.0 Definitions

3.1 Continuous Emission Monitoring System (CEMS) means the total equipment required for the determination of a pollutant concentration. The system consists of the following major subsystems:

3.2 Sample Interface means that portion of the CEMS used for one or more of the following: sample acquisition, sample transport, sample conditioning, and protection of the monitor from the effects of the stack effluent.

3.3 *Hg Analyzer* means that portion of the CEMS that measures the total vapor phase Hg mass concentration and generates a proportional output.

3.4 *Diluent Analyzer* (if applicable) means that portion of the CEMS that senses the diluent gas (CO_2) and generates an output proportional to the gas concentration.

3.5 *Data Recorder* means that portion of the CEMS that provides a permanent electronic record of the analyzer output. The data recorder can provide automatic data reduction and CEMS control capabilities.

3.6 *Span Value* means the upper limit of the intended Hg concentration measurement range. The span value is a value equal to two times the emission standard.

3.7 *Measurement Error (ME)* means the difference between the concentration indicated by the CEMS and the known concentration generated by a reference gas when the entire CEMS, including the sampling interface, is challenged. An ME test procedure is performed to document the accuracy and linearity of the CEMS at several points over the measurement range.

3.8 *Upscale Drift (UD)* means the difference in the CEMS output responses to a Hg reference gas when the entire CEMS, including the sampling interface, is challenged after a stated period of operation during which no unscheduled maintenance, repair, or adjustment took place.

3.9 *Zero Drift (ZD)* means the difference in the CEMS output responses to a zero gas when the entire CEMS, including the sampling interface, is challenged after a stated period of operation during which no unscheduled maintenance, repair, or adjustment took place.

3.10 *Relative Accuracy (RA)* means the absolute mean difference between the pollutant concentration(s) determined by the CEMS and the value determined by the reference method (RM) plus the 2.5 percent error confidence coefficient of a series of tests divided by the mean of the RM tests or the applicable emission limit.

4.0 Interferences [Reserved]

5.0 Safety

The procedures required under this performance specification may involve hazardous materials, operations, and equipment. This performance specification may not address all of the safety problems associated with these procedures. It is the responsibility of the user to establish appropriate safety and health practices and determine the applicable regulatory limitations prior to performing these procedures. The CEMS user's manual and materials recommended by the reference method should be consulted for specific precautions to be taken.

6.0 Equipment and Supplies

6.1 CEMS Equipment Specifications.

6.1.1 Data Recorder Scale. The CEMS data recorder output range must include zero and a high level value. The high level value must be approximately 2 times the Hg concentration corresponding to the emission standard level for the stack gas under the circumstances existing as the stack gas is sampled. If a lower high level value is used, the CEMS must have the capability of providing multiple high level values (one of which is equal to the span value) or be capable of automatically changing the high level value as required (up to specified high level value) such that the measured value does not exceed 95 percent of the high level value.

6.1.2 The CEMS design should also provide for the determination of response drift at both the zero and mid-level value. If this is not possible or practical, the design must allow these determinations to be conducted at a low-level value (zero to 20 percent of the high-level value) and at a value between 50 and 100 percent of the high-level value.

6.2 Reference Gas Delivery System. The reference gas delivery system must be designed so that the flowrate of reference gas introduced to the CEMS is the same at all three challenge levels specified in Section 7.1 and at all times exceeds the flow requirements of the CEMS.

6.3 Other equipment and supplies, as needed by the applicable reference method used. See Section 8.6.2.

7.0 Reagents and Standards

7.1 Reference Gases.

7.1.1 Zero—N_2 or Air. Less than 0.1 μg Hg/m^3.

7.1.2 Mid-level Hg^0 and $HgCl_2$. 40 to 60 percent of span.

7.1.3 High-level Hg^0 and $HgCl_2$. 80 to 100 percent of span.

7.2 Reagents and Standards. May be required for the reference methods. See Section 8.6.2.

8.0 Performance Specification Test Procedure

8.1 Installation and Measurement Location Specifications.

8.1.1 CEMS Installation. Install the CEMS at an accessible location downstream of all pollution control equipment. Since the Hg CEMS sample system normally extracts gas from a single point in the stack, use a location that has been shown to be free of stratification for SO_2 and NO_X through concentration measurement traverses for those gases. If the cause of failure to meet the RA test requirement is determined to be the measurement location and a satisfactory correction technique cannot be established, the Administrator may require the CEMS to be relocated.

Measurement locations and points or paths that are most likely to provide data that will meet the RA requirements are listed below.

8.1.2 Measurement Location. The measurement location should be (1) at least eight equivalent diameters downstream of the nearest control device, point of pollutant generation, bend, or other point at which a change of pollutant concentration or flow disturbance may occur, and (2) at least two equivalent diameters upstream from the effluent exhaust. The equivalent duct diameter is calculated as per 40 CFR part 60, appendix A, Method 1.

8.1.3 Hg CEMS Sample extraction Point. Use a sample extraction point (1) no less than 1.0 meter from the stack or duct wall, or (2) within the centroidal velocity traverse area of the stack or duct cross section.

8.2 Reference Method (RM) Measurement Location and Traverse Points. The RM measurement location should be at a point or points in the same stack cross sectional area as the CEMS is located, according to the criteria above. The RM and CEMS locations need not be immediately adjacent. They should be as close as possible without causing interference with one another.

8.3 Measurement Error (ME) Test Procedure. The Hg CEMS must be constructed to permit the introduction of known (NIST traceable) concentrations of elemental mercury (Hg^0) and mercuric chloride ($HgCl_2$) separately into the sampling system of the CEMS immediately preceding the sample extraction filtration system such that the entire CEMS can be challenged. Inject sequentially each of the three reference gases (zero, mid-level, and high level) for each Hg species. CEMS measurements of each reference gas shall not differ from their respective reference values by more than 5 percent of the span value. If this specification is not met, identify and correct the problem before proceeding.

8.4 Upscale Drift (UD) Test Procedure.

8.4.1 UD Test Period. While the affected facility is operating at more than 50 percent of normal load, or as specified in an applicable subpart, determine the magnitude of the UD once each day (at 24-hour intervals) for 7 consecutive days according to the procedure given in Sections 8.4.2 through 8.4.3.

8.4.2 The purpose of the UD measurement is to verify the ability of the CEMS to conform to the established CEMS response used for determining emission concentrations or emission rates. Therefore, if periodic automatic or manual adjustments are made to the CEMS zero and response settings, conduct the UD test immediately before these adjustments, or conduct it in such a way that the UD can be determined.

8.4.3 Conduct the UD test at the mid-level point specified in Section 7.1. Evaluate upscale drift for elemental Hg (Hg^0) only. Introduce the reference gas to the CEMS. Record the CEMS response and subtract the reference value from the CEM value (see example data sheet in Figure 12A–1).

8.5 Zero Drift (ZD) Test Procedure.

8.5.1 ZD Test Period. While the affected facility is operating at more than 50 percent of normal load, or as specified in an applicable subpart, determine the magnitude of the ZD once each day (at 24-hour intervals) for 7 consecutive days according to the procedure given in Sections 8.5.2 through 8.5.3.

8.5.2 The purpose of the ZD measurement is to verify the ability of the CEMS to conform to the established CEMS response used for determining emission concentrations or emission rates. Therefore, if periodic automatic or manual adjustments are made to the CEMS zero and response settings, conduct the ZD test immediately before these adjustments, or conduct it in such a way that the ZD can be determined.

8.5.3 Conduct the ZD test at the zero level specified in Section 7.1. Introduce the zero gas to the CEMS. Record the CEMS response and subtract the zero value from the CEM value (see example data sheet in Figure 12A–1).

8.6 Relative Accuracy (RA) Test Procedure.

8.6.1 RA Test Period. Conduct the RA test according to the procedure given in Sections 8.6.2 through 8.6.6 while the affected facility is operating at normal full load, or as specified in an applicable subpart. The RA test can be conducted during the UD test period.

8.6.2 Reference Method (RM). Unless otherwise specified in an applicable subpart of the regulations, use either Method 29 in appendix A to 40 CFR part 60, or ASTM Method D 6784–02 (incorporated by reference in § 60.17) as the RM for Hg. Do not include the filterable portion of the sample when making comparisons to the CEMS results. Conduct all RM tests with paired or duplicate sampling systems.

8.6.3 Sampling Strategy for RM Tests. Conduct the RM tests in such a way that they will yield results representative of the emissions from the source and can be compared to the CEMS data. It is preferable to conduct the diluent (if applicable), moisture (if needed), and Hg measurements simultaneously. However, diluent and moisture measurements that are taken within an hour of the Hg measurements can be used to adjust the results to a consistent basis. In order to correlate the CEMS and RM data properly, note the beginning and end of each RM test period for each paired RM run (including the exact time of day) on the CEMS chart recordings or other permanent record of output.

8.6.4 Number and length of RM Tests. Conduct a minimum of nine paired sets of all necessary RM test runs that meet the relative standard deviation criteria of this PS. Use a minimum sample run time of 2 hours for each pair.

Note: More than nine paired sets of RM tests can be performed. If this option is chosen, test results can be rejected so long as the total number of paired RM test results used to determine the CEMS RA is greater than or equal to nine. However, all data must be reported, including the rejected data.

8.6.5 Correlation of RM and CEMS Data. Correlate the CEMS and the RM test data as to the time and duration by first determining from the CEMS final output (the one used for reporting) the integrated average pollutant concentration or emission rate for each pollutant RM test period. Consider system response time, if important, and confirm that the results are on a consistent moisture, temperature, and diluent concentration basis with the paired RM test. Then, compare each integrated CEMS value against the corresponding average of the paired RM values.

8.6.6 Paired RM Outliers.

8.6.6.1 Outliers are identified through the determination of precision and any systematic bias of the paired RM tests. Data that do not meet this criteria should be flagged as a data quality problem. The primary reason for performing dual RM sampling is to generate information to quantify the precision of the RM data. The relative standard deviation (RSD) of paired data is the parameter used to quantify data precision. Determine RSD for two simultaneously gathered data points as follows:

$$RSD = 100\% * \left|(Ca - Cb)\right| / (Ca + Cb) \qquad \text{Eq. 12A-1}$$

where:

Ca and Cb are concentration values determined from trains A and B respectively. For RSD calculation, the concentration units are unimportant so long as they are consistent.

8.6.6.2 A minimum precision criteria for RM Hg data is that RSD for any data pair must be ≤10 percent as long as the mean Hg concentration is greater than 1.0 μg/m^3. If the mean Hg concentration is less than or equal to 1.0 μg/m^3, the RSD must be ≤20 percent. Pairs of RM data exceeding these RSD criteria should be eliminated from the data set used to develop a Hg CEMS correlation or to assess CEMS RA.

8.6.7 Calculate the mean difference between the RM and CEMS values in the units of the emission standard, the standard deviation, the confidence coefficient, and the RA according to the procedures in Section 12.0.

8.7 Reporting. At a minimum (check with the appropriate EPA Regional Office, State, or local Agency for additional requirements, if any), summarize in tabular form the results of the RD tests and the RA tests or alternative RA procedure, as appropriate. Include all data sheets, calculations, charts (records of CEMS responses), reference gas concentration certifications, and any other information necessary to confirm that the performance of the CEMS meets the performance criteria.

9.0 Quality Control [Reserved]

10.0 Calibration and Standardization [Reserved]

11.0 Analytical Procedure.

Sample collection and analysis are concurrent for this Performance Specification (see Section 8.0). Refer to the RM employed for specific analytical procedures.

12.0 Calculations and Data Analysis

Summarize the results on a data sheet similar to that shown in Figure 2–2 for Performance Specification 2.

12.1 Consistent Basis. All data from the RM and CEMS must be on a consistent dry basis and, as applicable, on a consistent diluent basis. Correct the RM and CEMS data for moisture and diluent as follows:

12.1.1 Moisture Correction (as applicable). Correct each wet RM run for moisture with the corresponding Method 4 data; correct each wet CEMS run using the corresponding CEMS moisture monitor date using Equation 12A–2.

$$\text{Concentration}_{(\text{dry})} = \frac{\text{Concentration}_{(\text{wet})}}{\left(1 - B_{ws}\right)} \qquad \text{Eq. 12A-2}$$

12.1.2 Correction to Units of Standard (as applicable). Correct each dry RM run to the units of the emission standard with the corresponding Method 3B data; correct each dry CEMS run using the corresponding CEMS diluent monitor data as follows:

12.1.3 Correct to Diluent Basis. The following is an example of concentration (ppm) correction to 7 percent oxygen.

$$\text{ppm}_{(\text{corr})} = \text{ppm}_{(\text{uncorr})}\left[\frac{20.9 - 7.0}{20.9 - \%O_{2\,(\text{dry})}}\right] \qquad \text{Eq. 12A-3}$$

The following is an example of mass/gross calorific value (lbs/million Btu) correction.

lbs/MMBtu = Conc$_{(dry)}$ (F-factor) ((20.9/(20.9 − percent O_2))

12.2 Arithmetic Mean. Calculate the arithmetic mean of the difference, d, of a data set as follows:

$$\bar{d} = \frac{1}{n}\sum_{i=1}^{n} d_i \qquad \text{Eq. 12A-4}$$

Where:

n = Number of data points.

12.3 *Standard Deviation. Calculate the standard deviation, S_d, as follows:*

$$S_d = \left[\frac{\sum_{i=1}^{n} d_i^2 - \frac{\left[\sum_{i=1}^{n} d_i\right]^2}{n}}{n-1}\right]^{\frac{1}{2}} \qquad \text{Eq. 12A-5}$$

Where:

$$\sum_{i=1}^{n} d_i = \text{Algebraic summation of the individual differences } d_i.$$

12.4 Confidence Coefficient. Calculate the 2.5 percent error confidence coefficient (one-tailed), CC, as follows:

$$CC = t_{0.975}\frac{S_d}{\sqrt{n}} \qquad \text{Eq. 12A-6}$$

12.5 Relative Accuracy. Calculate the RA of a set of data as follows:

$$RA = \frac{\left[\left|\bar{d}\right| + \left|CC\right|\right]}{\overline{RM}} \times 100 \qquad \text{Eq. 12A-7}$$

Where:

$|\bar{d}|$ = Absolute value of the mean differences (from Equation 12A–4).

|CC| = Absolute value of the confidence coefficient (from Equation 12A–6).

RM = Average RM value. In cases where the average emissions for the test are less than 50 percent of the applicable standard, substitute the emission standard value in the denominator of Eq. 12A–7 in place of RM. In all other cases, use RM.

13.0 Method Performance.

13.1 Measurement Error (ME). ME is assessed at mid-level and high-level values as given below using standards for both Hg^0 and $HgCl_2$. The mean difference between the indicated CEMS concentration and the reference concentration value for each standard shall be no greater than 5 percent of span. The same difference for the zero reference gas shall be no greater than 5 percent of span.

13.2 Upscale Drift (UD). The CEMS design must allow the determination of UD of the analyzer. The CEMS response can not drift or deviate from the benchmark value of the reference standard by more than 5 percent of span for the mid level value. Evaluate upscale drift for Hg^0 only.

13.3 Zero Drift (ZD). The CEMS design must allow the determination of drift at the zero level. This drift shall not exceed 5 percent of span.

13.4 Relative Accuracy (RA). The RA of the CEMS must be no greater than 20 percent of the mean value of the RM test data in terms of units of the emission standard, or 10 percent of the applicable standard, whichever is greater.

14.0 Pollution Prevention. [Reserved]

15.0 Waste Management. [Reserved]

16.0 Alternative Procedures. [Reserved]

17.0 Bibliography.

17.1 40 CFR part 60, appendix B, "Performance Specification 2—Specifications and Test Procedures for SO_2 and NO_X Continuous Emission Monitoring Systems in Stationary Sources."

17.2 40 CFR part 60, appendix A, "Method 29—Determination of Metals Emissions from Stationary Sources."

17.3 ASTM Method D6784–02, "Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method)."

18.0 Tables and Figures

TABLE 12A–1.—t-VALUES

n[a]	$t_{0.975}$	n_a	$t_{0.975}$	n_a	$t_{0.975}$
2	12.706	7	2.447	12	2.201
3	4.303	8	2.365	13	2.179
4	3.182	9	2.306	14	2.160
5	2.776	10	2.262	15	2.145
6	2.571	11	2.228	16	2.131

[a] The values in this table are already corrected for n–1 degrees of freedom. Use n equal to the number of individual values.

	Day	Date and time	Reference value (C)	CEMS value (M)	Measurement error	Drift
Zero Level						
Mid-level						
High-level						

Figure 12A–1. Zero and Upscale Drift Determination.

PART 63—[AMENDED]

4. The authority citation for part 63 continues to read as follows:

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

5. Section 63.14 is amended by adding paragraph (b)(35) to read as follows:

§ 63.14 Incorporations by Reference.

* * * * *

(b) * * *

(35) ASTM D6784–02, Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), for appendix B to part 63, Method 324.

* * * * *

6. Part 63 is amended by adding subpart UUUUU to read as follows:

Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants for Coal-or Oil-Fired Electric Utility Steam Generating Units

Sec.

Notifications, Reports, and Records

Other Requirements and Information

Tables to Subpart UUUUU of Part 63

What This Subpart Covers

§ 63.9980 What is the purpose of this subpart?

This subpart establishes national emissions limitations for hazardous air pollutants (HAP) emitted from coal-fired electric utility steam generating units and oil-fired electric utility steam generating units. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emissions limitations.

§ 63.9981 Am I subject to this subpart?

You are subject to this subpart if you own or operate a coal-fired electric utility steam generating unit or an oil-fired electric utility steam generating unit.

§ 63.9982 What parts of my facility does this subpart cover?

(a) The affected source is each group of one or more coal- or oil-fired electric utility steam generating units located at a facility. An electric utility steam generating unit that combusts natural gas at greater than or equal to 98 percent of the unit's annual fuel consumption is not an affected source under this subpart.

(b) A coal or oil-fired electric utility steam generating unit is a new affected source if you commenced construction of the unit after January 30, 2004.

(c) An affected source is reconstructed if you meet the criteria as defined in § 63.2. An existing electric utility steam generating unit that is switched completely to burning a different coal rank or fuel type is considered to be an existing affected source under this subpart.

(d) An affected source is existing if it is not new or reconstructed.

§ 63.9983 When do I have to comply with this subpart?

(a) If you have a new or reconstructed affected source, you must comply with this subpart according to paragraph (a)(1) or (2) of this section.

(1) If you start up your affected source before [DATE THE FINAL RULE IS PUBLISHED IN THE **Federal Register**], then you must comply with the emissions limitations and work practice standards for new and reconstructed sources in this subpart no later than [DATE THE FINAL RULE IS PUBLISHED IN THE **Federal Register**].

(2) If you startup your affected source on or after [DATE THE FINAL RULE IS PUBLISHED IN THE **Federal Register**], then you must comply with the emissions limitations and work practice standards for new and reconstructed sources in this subpart upon startup of your affected source.

(b) If you have an existing affected source, you must comply with the emissions limitations for existing sources no later than 3 years after [DATE THE FINAL RULE IS PUBLISHED IN THE **Federal Register**].

(c) You must meet the notification requirements according to the schedule applicable to your facility as specified in § 63.10300 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emissions limitations in this subpart.

Emissions Limitations

§ 63.9990 What emissions limitations must I meet for coal-fired electric utility steam generating units?

(a) For each coal-fired electric utility steam generating unit other than an integrated gasification combined-cycle (IGCC) electric utility steam generating unit, you must meet the mercury (Hg) emissions limit in paragraphs (a)(1) through (5) of this section that applies to your unit. The Hg emissions limits in paragraphs (a)(1) through (5) of this section are based on a 12-month rolling average using the procedures in § 63.10009.

(1) For each coal-fired electric utility steam generating unit that burns only bituminous coal, you must meet the Hg emissions limit in either paragraph (a)(1)(i) or (ii) of this section that applies to you.

(i) You must not discharge into the atmosphere from an existing affected source any gases which contain Hg in excess of 2.0 pound per trillion British thermal unit (lb/TBtu) on an input basis or 21×10^{-6} pound per Megawatt hour (lb/MWh) on an output basis.

(ii) You must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 6.0×10^{-6} lb/MWh on an output basis.

(2) For each coal-fired electric utility steam generating unit that burns only subbituminous coal, you must meet the Hg emissions limit in either paragraph (a)(2)(i) or (ii) of this section that applies to you.

(i) You must not discharge into the atmosphere any gases from an existing affected source which contain Hg in excess of 5.8 lb/TBtu on an input basis or 61×10^{-6} lb/MWh on an output basis.

(ii) You must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 20×10^{-6} lb/MWh on an output basis.

(3) For each coal-fired electric utility steam generating unit that burns only lignite coal, you must meet the Hg emissions limit in either paragraph (a)(3)(i) or (ii) of this section that applies to you.

(i) You must not discharge into the atmosphere any gases from an existing affected source which contain Hg in excess of 9.2 lb/TBtu on an input basis or 98×10^{-6} lb/MWh on an output basis.

(ii) You must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 62×10^{-6} lb/MWh on an output basis.

(4) For each coal-burning electric utility steam generating unit that burns only coal refuse, you must meet the Hg emissions limit in either paragraph (a)(4)(i) or (ii) of this section that applies to you.

(i) You must not discharge into the atmosphere any gases from an existing affected source which contain Hg in excess of 0.38 lb/TBtu on an input basis or 4.1×10^{-6} lb/MWh on an output basis.

(ii) You must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 1.1×10^{-6} lb/MWh on an output basis.

(5) For each coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks (*i.e.*, bituminous coal, subbituminous coal, lignite) or a blend of coal and coal refuse, you must not discharge into the atmosphere any gases from a new or existing affected source that contain Hg in excess of the monthly unit-specific Hg emissions limit established

according to paragraph (a)(5)(i) or (ii) of this section, as applicable to your unit.

(i) If you operate a coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks or a blend of coal and coal refuse, you must not discharge into the atmosphere any gases from a new or existing affected source that contain Hg in excess of the computed weighted Hg emissions limit based on the proportion of energy output (in Btu) contributed by each coal type burned during the compliance period and its applicable Hg emissions limit in paragraphs (a)(1) through (4) of this section as determined using Equation 1 of this section. You must meet the weighted Hg emissions limit calculated using Equation 1 of this section by calculating the unit emission rate based on the total Hg loading of the unit and the total Btu or megawatt hours contributed by all fuels burned during the compliance period.

$$EL_b = \frac{\sum_{i=1}^{n} EL_i(HH_i)}{\sum_{i=1}^{n} HH_i} \qquad \text{(Eq. 1)}$$

Where:

EL_b = Total allowable Hg in lb/MWh (or lb/TBtu) that can be emitted to the atmosphere from any affected source being averaged under the blending provision.

EL_i = Hg emissions limit for the subcategory that applies to affected source i, lb/MWh (or lb/TBtu).

HH_i = Heat input to, or electricity output from, affected source i during the production period related to the corresponding H_i that falls within the compliance period, gross MWh generated or MMBtu heat input to the electric utility steam generating unit.

n = Number of coal ranks being averaged for an affected source.

(ii) If you operate a coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks or a blend of coal and coal refuse together with one or more non-regulated, supplementary fuels, you must not discharge into the atmosphere any gases from the unit that contain Hg in excess of the computed weighted Hg emission limit based on the proportion of energy output (in Btu) contributed by each coal type burned during the compliance period and its applicable Hg emissions limit in paragraphs (a)(1) through (4) of this section as determined using Equation 1 of this section. You must meet the weighted Hg emissions limit calculated using Equation 1 of this section by calculating the unit emission rate based on the total Hg loading of the unit and the total Btu or megawatt hours contributed by both regulated and nonregulated fuels burned during the compliance period.

(b) For each IGCC electric utility steam generating unit, you must meet the Hg emissions limit in either paragraph (b)(1) or (2) of this section that applies to you. The Hg emissions limits in this paragraph are based on a 12-month rolling average using the procedures in § 63.10009.

(1) You must not discharge into the atmosphere any gases from an existing affected source which contain Hg in excess of 19 lb/TBtu on an input basis or 200 x 10^{-6} lb/MWh on an output basis.

(2) You must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 20×10^{-6} lb/MWh on an output basis.

§ 63.9991 What emissions limitations must I meet for oil-fired electric utility steam generating units?

(a) For each oil-fired electric utility steam generating unit, you must meet the nickel (Ni) emissions limit in paragraphs (a)(1) and (2) of this section that applies to you, except as provided in paragraph (b) of this section.

(1) You must not discharge into the atmosphere any gases from an existing affected source which contain Ni in excess of 210 lb/TBtu on an input basis or 0.002 lb/MWh on an output basis.

(2) You must not discharge into the atmosphere any gases from a new affected source which contain Ni in excess of 0.0008 lb/MWh on an output basis.

(b) The emissions limit in paragraph (a) of this section does not apply to a new or existing oil-fired electric utility steam generating unit if during the reporting period, to burn 98 percent or more distillate oil exclusively as the fuel for the unit. The emissions limit in paragraph (a) of this section will apply immediately if you subsequently burn a fuel other than distillate oil in the unit.

(c) If you use an electrostatic precipitator (ESP) to meet the applicable Ni emissions limit, you must operate the ESP such that the hourly average voltage and secondary current (or total power input) do not fall below the limit established in the initial or subsequent performance test.

(d) If you use a control device or combination of control devices other than an ESP to meet the applicable Ni emissions limit, or you wish to establish and monitor an alternative operating limit and alternative monitoring parameters for an ESP, you must apply to the Administrator for approval of alternative monitoring under § 63.8(f).

§ 63.9992 What are my compliance options for multiple affected sources?

(a) If you have two or more coal-fired electric utility steam generating units at your facility that are subject to Hg emission limits in § 63.9990, you may choose to use the emissions averaging compliance approach specified in paragraph (b) of this section as an alternative to complying with the applicable Hg emission limits for each individual unit. You may use emissions averaging only under the conditions specified in paragraphs (a)(1) and (2) of this section.

(1) The emissions averaging compliance approach is applicable to coal-fired electric utility steam generating units subject to the Hg emission limits for existing affected sources under this subpart that are located at a common contiguous facility. The emissions averaging compliance approach is also applicable to coal-fired electric utility stream generating units subject to the Hg emission limits for new affected sources under this subpart as long as they meet the new source limits specified under this subpart.

(2) All of the Hg emission limits used for the emissions averaging compliance approach must meet the applicable limits expressed in the same format (*i.e.*, all of the Hg emission limits must be either the applicable lb/TBtu limit values or the applicable lb/MWh limit values).

(b) If you choose to use the emissions averaging compliance approach, you must meet the requirements specified in paragraphs (b)(1) through (5) of this section.

(1) You must designate your emissions averaging source group by identifying each of the existing coal-fired electric utility stream generating units at your facility site to be included in your emissions averaging source group.

(2) You must designate a common Hg emissions limit format to be used for all of the coal-fired electric utility stream generating units in your designated emissions averaging source group (either the lb/TBtu limit format or the lb/MWh limit format).

(3) You must determine the Hg emissions limit value in § 63.9990 for your selected format that is applicable to each of the individual coal-fired electric utility stream generating units in your designated emissions averaging source group.

(4) You must calculate the unit-specific Hg emissions limit for your

designated emissions averaging source group using Equation 1 of this section.

$$AvEL = \frac{\sum_{i=1}^{n} L_i(V_i)}{\sum_{i=1}^{n} V_i} \qquad \text{(Eq. 1)}$$

Where:

AvEL = Total allowable Hg that can be emitted to the atmosphere from all emission sources in the emissions averaging group, lb/MWh or lb/TBtu;

L_i = Hg emissions limit for the subcategory that applies to emission source i or the calculated emissions limit derived for an emissions averaging group using Equation 1 of this section, lb/MWh or lb/MMBtu;

V_i = Volume of production for emissions source i during the production period related to the corresponding L_i that falls within the 12-month compliance period, gross MWh generated or MMBtu heat input to the electric utility steam generating unit; and

n = Number of emissions sources being averaged. This number may apply to individual emissions sources or emissions averaging groups.

(5) You must not discharge into the atmosphere any gases from your designated emissions averaging group that contain Hg in excess of the unit-specific Hg emissions limit established according to paragraph (b)(4) of this section as determined based on a 12-month rolling average using the procedures in § 63.10009.

(c) You may use the emissions averaging compliance approach or revise an existing emissions averaging group at any time after the compliance date by submitting an emissions averaging plan or revision, respectively, using the title V operating permit amendment process specified by the regulating authority. The emissions averaging plan must contain the information specified in paragraphs (c)(1) and (2) of this section.

(1) Identification of each coal-fired electric utility steam generating unit in your designated emissions averaging group and the applicable Hg emissions limit for each unit as determined in paragraph (b) of this section.

(2) The Hg emissions limit for your designated emissions averaging group as determined in paragraph (b) of this section, including all calculations and supporting information.

General Compliance Requirements

§ 63.10000 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emissions limitations (including operating limits) in this subpart at all times, except during periods of startup, shutdown, and malfunction.

(b) You must always operate and maintain your affected source, including air pollution control and monitoring equipment, according to the provisions in § 63.6(e)(1)(i).

(c) For each monitoring system required by this subpart, you must develop and submit to the Administrator for approval a unit-specific monitoring plan according to the requirements in § 63.10008(f).

(d) You must conduct a performance evaluation of each continuous monitoring system (CMS) in accordance with your unit-specific monitoring plan.

(e) You must operate and maintain the CMS in continuous operation according to the unit-specific monitoring plan.

(f) You must develop and implement a written startup, shutdown, and malfunction plan (SSMP) according to the provisions in § 63.6(e)(3).

Initial Compliance Requirements

§ 63.10005 By what date must I conduct performance tests or other initial compliance demonstrations?

(a) For each existing affected source, you must conduct performance tests, set operating limits, and conduct monitoring equipment performance evaluations, as applicable to your source, by the compliance date that is specified for your source in § 63.9983 and according to the applicable provisions in § 63.7(a)(2).

(b) For each new affected source, you must conduct performance tests, set operating limits, and conduct monitoring equipment performance evaluations, as applicable to your source, within 180 days after the compliance date that is specified for your source in § 63.9983 and according to the provisions in § 63.7(a)(2).

§ 63.10006 When must I conduct subsequent performance tests?

For each affected oil-fired electric utility steam generating units subject to a Ni emissions limit in this subpart, you must conduct a subsequent performance test at least once each year to demonstrate compliance and include the results in the next semiannual compliance report.

§ 63.10007 What performance test procedures must I use?

(a) For each affected oil-fired electric utility steam generating unit subject to a Ni emissions limit under this subpart, you must conduct each performance test to demonstrate compliance with the applicable emissions limit according to the requirements in paragraphs (a)(1) through (4) of this section.

(1) You must conduct each performance test according to § 63.7(c), (d), (f), and (h) and the procedures in Table 1 to this subpart. You must also develop a site-specific test plan according to the requirements in § 63.7(c).

(2) You must conduct each performance test at the representative process operating conditions that are expected to result in the highest emissions of Ni, and you must demonstrate initial compliance and establish your operating limits based on this test.

(3) You may not conduct performance tests during periods of startup, shutdown, or malfunction.

(4) You must conduct three separate test runs for each performance test required in this section, as specified in § 63.7(e)(3). Each test run must last at least 1 hour.

(b) You must submit a Notification of Compliance Status report containing the results of the initial or annual compliance demonstration according to the requirements in § 63.10031(b).

§ 63.10008 What are my monitoring, installation, operation, and maintenance requirements?

(a) If you use an ESP to meet a Ni limit in this subpart, you must install and operate a continuous parameter monitoring system (CPMS) to measure and record the voltage and secondary current (or total power input) to the control device.

(b) You must install, operate, and maintain each CPMS by the compliance date specified in § 63.9983 according to the requirements in paragraphs (b)(1) through (3) of this section.

(1) Each CPMS must complete a minimum of one cycle of operation for each successive 15-minute period. You must have a minimum of four successive cycles of operation to have a valid hour of data.

(2) Each CPMS must determine the 1-hour block average of all recorded readings.

(3) You must record the results of each inspection, calibration, and validation check for a CPMS.

(c) You must install and operate a continuous emissions monitoring system (CEMS) to measure and record the concentration of Hg in the exhaust gases from each stack.

(d) You must install, operate, and maintain each CEMS by the compliance date specified in § 63.9983 according to the requirements in paragraphs (d)(1) through (4) of this section.

(1) You must install, operate, and maintain each CEMS according to Performance Specification 12A in 40 CFR part 60, appendix B.

(2) You must conduct a performance evaluation of each CEMS according to the requirements of § 63.8 and Performance Specification 12A in 40 CFR part 60, appendix B. id.

(3) You must operate each CEMS according to the requirements in paragraphs (d)(3)(i) through (iv) of this section.

(i) As specified in 63.8(c)(4)(ii), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(ii) You must reduce CEMS data as specified in § 63.8(g)(2).

(iii) Each CEMS must determine and record the 1 hour average emissions using all the hourly averages collected for periods during which the CEMS is not out of control.

(iv) You must record the results of each inspection, calibration, and validation check.

(4) The provisions in paragraphs (d)(4)(i) through (iv) of this section apply to data collection periods for your Hg CEMS.

(i) A complete day of data for continuous monitoring is 18 hours or more in a 24-hour period.

(ii) A complete month of data for continuous monitoring is 21 days or more in a calendar month.

(iii) If you collect less than 21 days of continuous emissions data, you must discard the data collected that month and replace that data with the mean of the individual monthly emission rate values determined in the last 12 months.

(iv) If you collect less than 21 days per monthly period of continuous data again in that same 12-month rolling average cycle, you must discard the data collected that month and replace that data with the highest individual monthly emission rate determined in the last 12 months.

(e) As an alternative to the CEMS required in paragraph (c) of this section, the owner or operator must monitor Hg emissions using Method 324 in 40 CFR part 63, appendix A.

(f) You must prepare and submit to the Administrator for approval a unit-specific monitoring plan for each monitoring system. You must comply with the requirements in your plan. The plan must address the requirements in paragraphs (f)(1) through (6) of this section.

(1) Installation of the CMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (*e.g.*, at or downstream of the last control device);

(2) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems;

(3) Performance evaluation procedures and acceptance criteria (*e.g.*, calibrations);

(4) Ongoing operation and maintenance procedures in accordance with the general requirements of § 63.8(c)(1), (3), and (4)(ii);

(5) Ongoing data quality assurance procedures in accordance with the general requirements of § 63.8(d); and

(6) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of § 63.10(c), (e)(1) and (e)(2)(i).

(g) Quarterly accuracy determinations and daily calibration drift tests for gaseous Hg CEMS shall be performed in accordance with Procedure 1 (appendix F of 40 CFR part 60). Annual relative accuracy test audits (RATAs) for Hg sorbent trap monitoring systems shall also be performed in accordance with Procedure 1.

§ 63.10009 How do I demonstrate initial compliance with the emissions limitations?

(a) You must demonstrate initial compliance with each emission limitation in § 63.9990 that applies to you according to Table 2 to this subpart.

(b) If you elect to comply with an emissions limit using emissions averaging according to the requirements in § 63.9992, you must demonstrate compliance with the emissions limit established for each emissions averaging group for the 12-month compliance period using Equation 1 of this section.

$$AvH = \frac{\sum_{i=1}^{n} H_i}{\sum_{i=1}^{n} V_i} \qquad \text{(Eq. 1)}$$

Where:

AvH = Total Hg emitted for the 12-month compliance period, lb/MWh or lb/MMBtu;

H_i = Total mass of measured Hg from AvEL emissions averaging group i during the 12-month compliance period, lb;

V_i = Total volume of production from AvEL emissions averaging group i during 12-month compliance period, gross MWh generated or MMBtu heat input to the electric utility steam generating unit; and

n = Number of emission sources in the emissions averaging group or number of emission averaging groups.

(c) If your affected electric utility steam generating unit is also a cogeneration unit, you must use the procedures in paragraphs (c)(1) and (2) of this section to calculate emission rates based on electrical output to the grid plus half of the equivalent electrical energy in the unit's process stream.

(1) All conversions from Btu/hr unit input to MWe unit output must use equivalents found in 40 CFR part 60.40(a)(1) for electric utilities (*i.e.*, 250 million Btu/hr input to an electric utility steam generating unit is equivalent to 73 MWe input to the electric utility steam generating unit); 73 MWe input to the electric utility steam generating unit is equivalent to 25 MWe output from the boiler electric utility steam generating unit; therefore, 250 million Btu input to the electric utility steam generating unit is equivalent to 25 MWe output from the electric utility steam generating unit).

(2) You must use the Equation 2 of this section to determine the cogeneration Hg or Ni emission rate over a specific compliance period.

$$ER_{cogen} = \frac{E}{\left(\left(V_{grid}\right) + \left(\frac{V_{process}}{2}\right)\right)} \qquad \text{(Eq. 2)}$$

Where:

ER_{cogen} = Cogeneration Hg or Ni emission rate over a compliance period in lb/MWh (or lb Hg/TBtu);
E = Mass of Hg or Ni emitted from the stack over the same compliance period (lb Hg or lb Ni);
V_{grid} = Amount of energy sent to the grid over the same compliance period (MWh or TBtu); and
$V_{process}$ = Amount of energy converted to steam for process use over the same compliance period (MWh or TBtu).

(d) If your coal-fired electric utility steam generating unit is subject to an Hg limit in § 63.9990, you must determine initial compliance according to the applicable requirements in paragraphs (d)(1) through (4) of this section.

(1) Begin compliance monitoring on the effective date of this subpart.

(2) If you use a CEMS, determine the 12-month rolling average Hg emission rate according to the applicable procedures in paragraphs (d)(2)(i) through (iii) of this section.

(i) Calculate the total mass of Hg emissions over a month (M), in micrograms (μg), using Equation 3 of this section.

$$M = \int_0^t C(t)V(t)dt \qquad \text{(Eq. 3)}$$

Where:

M = Total mass of Hg emissions, (μg);
C = Concentration of Hg recorded by CEMS per Performance Specification 12A, micrograms per dry standard cubic meter (μg/dscm);
V = Volumetric flow rate recorded at the same frequency as the CEMS reading for the Hg concentration indicated in Performance Specification 12A, cubic meters per hour (dscm/hr); and
t = total time period over which mass measurements are collected, (hr).

(ii) Calculate the Hg emission rate for an input-based limit (lb/TBtu) using Equation 4 of this section.

$$ER = \frac{M \times \text{conversion factor}}{TP} \qquad \text{(Eq. 4)}$$

Where:

ER = Hg emission rate, (lb/TBtu);
M = Total mass of Hg emissions, micrograms (μg);
Conversion factor = 2.205 × 10 $^{minus;9}$, used to convert micrograms to pounds; and
$TP_{input\text{-}based}$ = Total power, (TBtu).

(iii) Calculate the Hg emission rate for an output-based limit (lb/MWh) using Equation 5 of this section:

$$ER = \frac{M \times \text{conversion factor}}{TP_{output\text{-}based}} \qquad \text{(Eq. 5)}$$

Where:

ER = Hg emission rate, (lb/MWh);
M = Total mass of Hg emissions, (μg);
Conversion factor = 2.205 × 10 $^{minus;9}$; and
$TP_{output\text{-}based}$ = Total power, megawatt-hours (MWh).

(3) If you use Method 324 (40 CFR part 63, appendix A), determine the 12-month rolling average Hg emission rate according to the applicable procedures in paragraphs (d)(3)(i) through (v) of this section.

(i) Sum the Hg concentrations for the emission rate period, (μg/dscm).

(ii) Calculate the total volumetric flow for the emission rate period, (dscm).

(iii) Multiply the total Hg concentration times the total volumetric flow to obtain the total mass of Hg for the emissions rate period in micrograms.

(iv) Calculate the Hg emissions rate for an input-based limit (lb/TBtu) using Equation 4 of this section.

(v) Calculate the Hg emissions rate for an output-based limit (lb/MWh) using Equation 5 of this section.

(4) Report the 12-month rolling average Hg emissions rate in the first semiannual compliance report.

(e) If your oil-fired unit is subject to a Ni emissions limit in § 63.9991, you must determine initial compliance using the applicable procedures in paragraphs (e)(1) through (3) of this section.

(1) Begin compliance monitoring on the effective date of this subpart.

(2) Use the applicable procedures in paragraphs (e)(2)(i) through (v) of this section to convert the Method 29 Ni measurement to the selected format.

(i) Sum the Ni concentrations obtained from the Method 29 test runs, milligrams per dscm (mg/dscm).

(ii) Calculate the total volumetric flow obtained during the Method 29 test runs, (dscm).

(iii) Multiply the total Ni concentration times the total volumetric flow for the duration of the initial compliance testing period to obtain the total mass of Ni in milligrams.

(iv) Calculate the input-based Ni emissions rate in a lb/TBtu format using Equation 6 of this section.

$$ER = \frac{M \times \text{conversion factor}}{TP_{input\text{-}based}} \qquad \text{(Eq. 6)}$$

Where:

ER = Ni emissions rate, (lb/TBtu);
M = Total mass of Ni emissions, (mg);
Conversion factor = 2.205×10^{-6}, used to convert milligrams to pounds; and
$TP_{input\text{-}based}$ = Total power, (TBtu).

(v) Calculate the output-based Ni emissions rate in a lb/MWh format using Equation 7 of this section.

$$ER = \frac{M \times \text{conversion factor}}{TP_{output\text{-}based}} \qquad \text{(Eq. 7)}$$

Where:

ER = Ni emissions rate, (lb/MWh);
M = Total mass of Ni emissions, (mg);
Conversion factor = 2.205×10^{-6} and
$TP_{output\text{-}based}$ = Total power, (MWH).

(f) You must submit the Notification of Compliance Status report containing the results of the initial compliance demonstration according to the requirements in § 63.10030(e).

Continuous Compliance Requirements

§ 63.10020 How do I monitor and collect data to demonstrate continuous compliance?

(a) Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), you must monitor continuously (or collect data at all required intervals) at all times that the affected source is operating.

(b) You may not use data recorded during monitoring malfunctions, associated repairs, or required quality assurance or control activities, in data averages and calculations used to report emission or operating levels. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

(c) A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions. Any period for which the monitoring system is out-of-control and data are not available for required calculations constitutes a deviation from the monitoring requirements.

§ 63.10021 How do I demonstrate continuous compliance with the emissions limitations?

(a) You must demonstrate continuous compliance with each emission limitation that applies to you according to the methods specified in Table 3 to this subpart.

(b) During periods of startup, shutdown, and malfunction, you must operate in accordance with the startup, shutdown, and malfunction plan as required in § 63.10000(f).

(c) Consistent with §§ 63.6(e) and 63.7(e)(1), deviations that occur during a period of startup, shutdown, or malfunction are not violations if you demonstrate to the Administrator's satisfaction that you were operating in accordance with the startup, shutdown, and malfunction plan. The Administrator will determine whether deviations that occur during a period of startup, shutdown, or malfunction are violations, according to the provisions in § 63.6(e).

Notification, Reports, and Records

§ 63.10030 What notifications must I submit and when?

(a) You must submit all of the notifications in §§ 63.6(h)(4) and (5), 63.7(b) and (c), 63.8(e), 63.8(f)(4) and (6), and 63.9(b) through (h) that apply to you by the dates specified. Except as provided in paragraph (f) of this section, if you comply with the requirements in § 63.9991(b) for switching fuel, you must notify the Administrator in writing at least 30 days prior to using a fuel other than distillate oil.

(b) As specified in § 63.9(b)(2), if you operate an affected source before [DATE OF PUBLICATION OF THE FINAL RULE IN THE **Federal Register**], you must submit an Initial Notification not later than 120 days after [DATE THE FINAL RULE IS PUBLISHED IN THE **Federal Register**]. The Initial Notification must include the information required in paragraphs (b)(1) through (4) of this section, as applicable.

(1) The name and address of the owner or operator;

(2) The address (*i.e.*, physical location) of the affected source;

(3) An identification of the relevant standard, or other requirement, that is the basis of the notification and the source's compliance date;

(4) A brief description of the nature, size, design and method of operation of the source and an identification of the types of emission points within the affected source subject to the requirements and the Hg or Ni pollutant being emitted.

(c) If you startup your new or reconstructed affected source on or after [DATE THE FINAL RULE IS PUBLISHED IN THE **Federal Register**], you must submit an Initial Notification not later than 120 days after you become subject to this subpart. The Initial Notification must include the information required in paragraphs (c)(1) through (4) of this section, as applicable.

(1) The name and address of the owner or operator;

(2) The address (*i.e.*, physical location) of the affected source;

(3) An identification of the relevant standard, or other requirement, that is the basis of the notification and the source's compliance date;

(4) A brief description of the nature, size, design and method of operation of the source and an identification of the types of emission points within the affected source subject to the requirements and the Hg or Ni pollutant being emitted.

(d) If you are required to conduct a performance test, you must submit a notification of intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in § 63.7(b)(1).

(e) If you are required to conduct a performance test or other initial compliance demonstration as specified in § 63.10007, you must submit a Notification of Compliance Status report according to § 63.9(h)(2)(ii) and the requirements specified in paragraphs (e)(1) through (3) of this section.

(1) For each initial compliance demonstration, you must submit the Notification of Compliance Status report, including all performance test results, before the close of business on the 60th day following the completion of the performance test and/or other initial compliance demonstrations according to § 63.10(d)(2).

(2) The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(2)(i) through (iv) of this section, as applicable.

(i) A description of the affected source(s) including identification of which subcategory the source is in, the capacity of the source, a description of the add-on controls used on the source description of the fuel(s) burned, and justification for the worst-case fuel burned during the performance test.

(ii) Summary of the results of all performance tests, fuel analyses, and calculations conducted to demonstrate initial compliance including all established operating limits.

(iii) A signed certification that you have met all applicable emissions limitations, including any emission limitation for an emissions averaging group.

(iv) If you had a deviation from any emission limitation, you must also submit a description of the deviation, the duration of the deviation, and the corrective action taken in the Notification of Compliance Status report.

(f) If you comply with the requirements in § 63.9991(b) by using distillate fuel, and you must switch fuel because of an emergency, you must notify the Administrator in writing within 30 days of using a fuel other than distillate oil.

§ 63.10031 What reports must I submit and when?

(a) Compliance report due dates. Unless the Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit a semiannual compliance report to the permitting authority according to the requirements in paragraphs (a)(1) through (5) of this section.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.9983 and ending on June 30 or December 31, whichever date comes first after the compliance date that is specified for your affected source in § 63.9983.

(2) The first compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date comes first after the first compliance report is due.

(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) Each subsequent compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date comes first after the end of the semiannual reporting period.

(5) For each affected source that is subject to permitting regulations pursuant to 40 CFR part 70 or 40 CFR part 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (a)(1) through (4) of this section.

(b) Compliance report contents. The compliance report must contain the information required in paragraphs (b)(1) through (5) of this section and, as applicable, paragraphs (b)(6) through (10) of this section.

(1) Company name and address.

(2) Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during this test, if applicable.

(5) If you had a startup, shutdown, or malfunction during the reporting period and you took actions consistent with your SSMP, the compliance report must include the information in § 63.10(d)(5)(i).

(6) If there are no deviations from any emission limitation (emissions limit or operating limit) in this subpart that apply to you, a statement that there were no deviations from the emissions limitations during the reporting period.

(7) If there were no periods during which a CMS, including CEMS or CPMS, was out-of-control as specified in § 63.8(c)(7), a statement that there were no periods during which the CMS were out-of-control during the reporting period.

(8) For each deviation from an emission limitation (emissions limit or operating limit) in this subpart that occurs at an affected source where you are not using a CMS to comply with that emission limitation, the compliance report must contain the information in paragraphs (b)(8)(i) through (iii) of this section. This includes periods of startup, shutdown, and malfunction.

(i) The total operating time of each affected source during the reporting period.

(ii) Information on the number, duration, and cause of the deviation (including unknown cause) as applicable and the corrective action taken.

(iii) A copy of the test report if the annual performance test showed a deviation from the Ni emissions limit or a deviation from the Hg emissions limit.

(9) For each deviation from an emission limitation (emissions limit or operating limit) in this subpart occurring at an affected source where you are using a CMS to comply with that emission limitation, you must include the information in paragraphs (b)(9)(i) through (xii) of this section. This includes periods of startup, shutdown, and malfunction and any deviations from your unit-specific monitoring plan as required in § 63.10000(c).

(i) The date and time that each malfunction started and stopped and description of the nature of the deviation (*i.e.*, what you deviated from).

(ii) The date and time that each CMS was inoperative, except for zero (low-level) and high-level checks.

(iii) The date, time, and duration that each CMS was out-of-control, including the information in § 63.8(c)(8).

(iv) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(v) A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period.

(vi) A breakdown of the total duration of the deviations during the reporting period into those that are due to startup, shutdown, control equipment problems, process problems, other known causes, and other unknown causes.

(vii) A summary of the total duration of CMS downtime during the reporting period and the total duration of CMS downtime as a percent of the total source operating time during that reporting period.

(viii) An identification of each parameter that was monitored at the affected source for which there was a deviation, including opacity, carbon monoxide, and operating parameters for wet scrubbers and other control devices.

(ix) A brief description of the source for which there was a deviation.

(x) A brief description of each CMS for which there was a deviation.

(xi) The date of the latest CMS certification or audit for the system for which there was a deviation.

(xii) A description of any changes in CMS, processes, or controls since the last reporting period for the source for which there was a deviation.

(10) A statement that each emissions averaging group was in compliance with its applicable limit during the semiannual reporting period.

(c) Immediate startup, shutdown, and malfunction report. If you had a startup, shutdown, or malfunction during the semiannual reporting period that was not consistent with your SSMP, you must submit an immediate startup, shutdown, and malfunction report according to the requirements of § 63.10(d)(5)(ii).

(d) Part 70 monitoring report. Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 40 CFR part 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a compliance report along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limitation (including any operating limit), submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report. However, submission of a compliance report does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permitting authority.

§ 63.10032 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) through (3) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in § 63.10(b)(2)(xiv).

(2) The records in § 63.6(e)(3)(iii) through (v) related to startup, shutdown, and malfunction.

(3) Records of performance tests or other compliance demonstrations and performance evaluations as required in § 63.10(b)(2)(viii).

(b) For each monitoring system required by this subpart, you must keep records according to paragraphs (b)(1) through (4) of this section.

(1) Records described in § 63.10(b)(2)(vi) through (xi).

(2) Previous (*i.e.*, superseded) versions of the performance evaluation plan as required in § 63.8(d)(3).

(3) Request for alternatives to relative accuracy test for CEMS as required in § 63.8(f)(6)(i).

(4) Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(c) You must keep the records required in Table 3 to this subpart including records of all monitoring data to show continuous compliance with each emission limitation that applies to you.

§ 63.10033 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review, according to § 63.10(b)(1).

(b) As specified in § 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1). You can keep the records offsite for the remaining 3 years.

Other Requirements and Information

§ 63.10040 What parts of the General Provisions apply to me?

Table 4 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you.

§ 63.10041 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the U.S. Environmental Protection Agency (U.S. EPA), or a delegated authority such as your State, local, or tribal agency. If the Administrator has delegated authority to your State, local, or tribal agency, then that agency has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority to this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the Administrator and are not transferred to the State, local, or tribal agency. The U.S. EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(c) The authorities that will not be delegated to State, local, or tribal agencies are listed in paragraphs (c)(1) through (5) of this section.

(1) Approval of alternatives to the non-opacity emission limits in 63.9990(a) through (g) under § 63.6(g).

(2) Approval of major alternatives to test methods under § 63.7(e)(2)(ii) and (f) and as defined in § 63.90.

(3) Approval of major alternatives to monitoring under § 63.8(f) and as defined in § 63.90.

(4) Approval of major alternatives to recordkeeping and reporting under § 63.10(f) and as defined in § 63.90.

(5) Approval of the unit-specific monitoring plan under § 63.10000(c).

§ 63.10042 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act, in § 63.2, and in this section as follows:

Anthracite coal means solid fossil fuel classified as anthracite coal by ASTM Designation D388–77, 90, 91, 95, or 98a (incorporated by reference—see 40 CFR 60.17).

Bituminous coal means solid fossil fuel classified as bituminous coal by ASTM D388–77, 90, 91, 95, or 98a (incorporated by reference—see 40 CFR 60.17).

Coal means all solid fossil fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM Designation D388–77, 90, 91, 95, or 98a (incorporated by reference—see 40 CFR 60.17).

Coal refuse means waste products of coal mining, physical coal cleaning, and coal preparation operations (*e.g.*, culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

Coal-fired electric utility steam generating unit means an electric utility steam generating unit that burns coal, coal refuse, or a synthetic gas derived from coal either exclusively, in any combination together, or in any combination with other supplemental fuels. Examples of supplemental fuels include, but are not limited to, petroleum coke and tire-derived fuels.

Combined-cycle gas turbine means a stationary turbine combustion system where heat from the turbine exhaust gases is recovered by a waste heat boiler.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limitation (including any operating limit) or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limitation (including any operating limit) or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396–78, 89, 90, 92, 96, or 98, Standard Specifications for Fuel Oils (incorporated by reference—see 40 CFR 60.17).

Electric utility steam generating unit means any fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is also considered an electric utility steam generating unit.

Electrostatic precipitator means an add-on air pollution control device used to capture particulate matter by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper.

Emission limitation means any emissions limit or operating limit.

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or §§ 51.18 and 51.24.

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Integrated gasification combined cycle (IGCC) electric utility steam generating unit means a coal-fired electric utility steam generating unit that burns a synthetic gas derived from coal in a combined-cycle gas turbine. No coal is directly burned in the unit during operation.

Lignite means solid fossil fuel classified as lignite coal by ASTM D388–77, 90, 91, 95, or 98a (incorporated by reference—see 40 CFR 60.17).

Oil means crude oil or petroleum or a liquid fuel derived from crude oil or petroleum, including distillate and residual oil.

Oil-fired electric utility steam generating unit means an electric utility steam generating unit that either burns oil exclusively, or burns oil alternately with burning fuels other than oil at other times.

Residual oil means crude oil, fuel oil numbers 1 and 2 that have a nitrogen content greater than 0.05 weight percent, and all fuel oil numbers 4, 5 and 6, as defined by the American Society of Testing and Materials in ASTM D396–78, Standard Specifications for Fuel Oils (incorporated by reference—see 40 CFR 60.17).

Responsible official means responsible official as defined in 40 CFR 70.2.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel fired steam generators associated with combined-cycle gas turbines; nuclear steam generators are not included).

Subbituminous coal means solid fossil fuel that is classified as subbituminous A, B, or C according to the American Society of Testing and Materials (ASTM) Standard Specification for Classification of Coals by Rank D388–77 (incorporated by reference—see 40 CFR 60.17).

Tables to Subpart UUUUU of Part 63

As stated in § 63.10007, you must comply with the following requirements for performance tests:

TABLE 1 TO SUBPART UUUUU OF PART 63.—PERFORMANCE TEST REQUIREMENTS FOR Ni AND Hg

For each affected source . . .	You must . . .	Using this method . . .	According to the following requirements . . .
1. Subject to Ni emissions limit	a. Select sampling port locations and number of traverse points in each stack or duct.	Method 1 or 1A (40 CFR part 60, appendix A).	Sampling sites must be located at the outlet of the control device (or at the outlet of the emissions source if no control device is present) prior to any releases to the atmosphere.
	b. Determine the volumetric flow rate of the stack gas.	Method 2, 2A, 2C, 2D, 2F, or 2G (40 CFR part 60, appendix A).	
	c. Determine the dry molecular weight of the stack gas.	Method 3A or 3B (40 CFR part 60, appendix A).	
	d. Determine the moisture content of the stack gas.	Method 4 (40 CFR part 60, appendix A).	
	e. Determine the Ni concentration	Method 29 (40 CFR part 60, appendix A) for Ni.	
2. Subject to Ni emissions limit and that use an ESP.	Establish operating limits for minimum voltage and secondary current or total power input.	Data from the current and voltage monitors for the ESP and the Ni performance test.	(1) Collect secondary current and voltage or total power input for the ESP every 15 minutes during the entire period of the three-run Ni performance test. (2) Determine the average secondary current and voltage or total power input by computing the average of all 15 minute readings taken during each test run. You must set the minimum operating limits equal to the minimum 1-hour average values measured during the three-run performance test.

As stated in § 63.10009, you must show initial compliance with the emissions limitations according to the following:

TABLE 2 TO SUBPART UUUUU OF PART 63.—INITIAL COMPLIANCE WITH EMISSIONS LIMITATIONS FOR Ni AND Hg

For . . .	That is controlled with . . .	You have demonstrated initial compliance if . . .
1. Each oil-fired unit subject to a Ni emissions limit in § 63.9991.	Electrostatic precipitator (ESP)	i. The average Ni emissions in lb/TBtu or lb/MWH over the three-run performance test do not exceed the applicable emissions limit. ii. You have a record of the average secondary current and voltage or total power input of the ESP for each test run over the three-run performance test during which the Ni emissions did not exceed the applicable limit.
2. Each oil-fired unit subject to alternative standard in § 63.9991(b) for fuel switching.	Any type	i. You submit a signed certification in the Notification of Compliance Status report that you burn only distillate oil as the fuel in your unit. ii. You have records demonstrating that you burn only distillate oil as the fuel in your unit.
3. Each coal-fired unit subject to Hg emissions limit in § 63.9990.	Any	You have established a site specific Hg limit according to the procedures in § 63.10009 and reported the limit in your Notification of Compliance Status.

As stated in § 63.10021, you must show continuous compliance with the emissions limitations according to the following:

TABLE 3 TO SUBPART UUUUU OF PART 63—CONTINUOUS COMPLIANCE WITH EMISSIONS LIMITATIONS FOR Hg AND Ni

For . . .	That is controlled with . . .	You must demonstrate continuous compliance by . . .
i. Each unit subject to Hg emissions limit in § 63.9990.	Any type	i. Continuously monitoring the hourly average Hg emissions using a CEMS or monitoring and recording the Hg measurements by semicontinous method. ii. Collecting and reducing the monitoring data according to § 63.100.20. iii. Calculating for each month the monthly rolling average emissions. iv. Maintaining the 12-month rolling average at or below the applicable limit.
2. Each unit subject to Ni limit in § 63.9991	Electrostatic precipitator	i. Collecting and reducing the secondary current and voltage (or total power input) monitoring data. ii. Maintaining the hoursly average secondary current and voltage or total power input at or above the limits established in the performance test. iii. Conducting performance tests at least once per year and reporting the results in the semiannual compliance report.
3. Each unit subject to alternative standard for distillate fuel switching in § 63.9991(b).	Any type	i. Submitting written certifications with each semiannual compliance report according to the requirements in § 63.10031(b) and keeping records of fuel burned to document compliance. ii. Notifying the Adminsitrator if resume burning fuel other than distillate oil according to the requirements in § 63.10030(a). iii. If at any time the unit does not meet the alternative limit, the owner or operator must immediately comply with the applicable Ni limit, including all initial and continuous compliance requirements.

As stated in § 63.10040, you must comply with the applicable General Provisions according to the following:

TABLE 4 TO SUBPART UUUUU OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART UUUUU

Citation	Subject	Brief description	Comments
§ 63.1	Applicability	Initial Applicability Determination; Applicability After Standard Established; Permit Requirements; Extensions, Notifications.	Yes.
§ 63.2	Definitions	Definitions for part 63 standards	Yes.
§ 63.3	Units and Abbreviations	Units and abbreviations for part 63 standards.	Yes.
§ 63.4	Prohibited Activities	Prohibited Activities; Compliance date; Circumvention, Severability.	Yes.
§ 63.5	Construction/Reconstruction	Applicability; applications; approvals	Yes.
§ 63.6(a)	Applicability	GP apply unless compliance extension and GP apply to area sources that become major.	Yes.
§ 63.6(b)(1)–(4)	Compliance Dates for New and Reconstructed sources.	Standards apply at effective date; 3 years after effective date; upon startup; 10 years after construction or reconstruction commences for 112(f).	Yes.
§ 63.6(b)(5)	Notification	Must notify if commenced construction or reconstruction after proposal.	Yes.
§ 63.6(b)(6)	[Reserved].		

TABLE 4 TO SUBPART UUUUU OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART UUUUU—Continued

Citation	Subject	Brief description	Comments
§ 63.6(b)(7)	Compliance Dates for New and Reconstructed Area Sources That Become Major.	Area sources that become major must comply with major source standards immediately upon becoming major, regardless of whether required to comply when they were an area source.	Yes.
§ 63.6(c)(1)–(2)	Compliance Dates for Existing Sources	Comply according to date in subpart, which must be no later than 3 years after effective date and for 112(f) standards, comply within 90 days of effective date unless compliance extension.	Yes.
§ 63.6(c)(3)–(4)	[Reserved].		
§ 63.6(c)(5)	Compliance Dates for Existing Area Sources That Become Major.	Area sources that become major must comply with major source standards by date indicated in subpart or by equivalent time period (for example, 3 years).	Yes.
§ 63.6(d)	[Reserved].		
§ 63.6(e)(1)–(2)	Operation & Maintenance	Operate to minimize emissions at all times. AND Correct malfunctions as soon as practicable AND Operation and maintenance requirements independently enforceable information Administrator will use to determine if operation and maintenance requirements were met	Yes.
§ 63.6(e)(3)	Startup, Shutdown, and Malfunction Plan (SSMP).	Requirement for SSM and startup, shutdown, malfunction plan. Content of SSMP	Yes.
§ 63.6(f)(1)	Compliance Except During SSM	Comply with emission standards at all times except during SSM.	Yes.
§ 63.6(f)(2)–(3)	Methods for Determining Compliance	Compliance based on performance test, operation and maintenance plans, records, inspection.	Yes.
§ 63.6(g)(1)–(3)	Alternative Standard	Procedures for getting an alternative standard.	Yes.
§ 63.6(h)(1)	Compliance with Opacity/VE Standards	Comply with opacity/VE emissions limitations at all times except during SSM.	No.
§ 63.6(h)(2)(i)	Determining Compliance with Opacity/Visible Emission (VE) Standards.	If standard does not state test method, use Method 9 for opacity and Method 22 for VE.	No.
§ 63.6(h)(2)(ii)	[Reserved].		
§ 63.6(h)(2)(iii)	Using Previous Tests to Demonstrate Compliance with Opacity/VE Standards.	Criteria for when previous opacity/VE testing can be used to show compliance with this rule.	No.
§ 63.6(h)(3)	[Reserved].		
§ 63.6(h)(4)	Notification of Opacity/VE Observation Date.	Notify Administrator of anticipated date of observation.	No.
§ 63.6(h)(5)(i), (iii)–(v)	Conducting Opacity/VE Observations	Dates and Schedule for conducting opacity/VE observations.	No.
§ 63.6(h)(5)(ii)	Opacity Test Duration and Averaging Times.	Must have at least 3 hours of observation with thirty, 6-minute averages.	No.
§ 63.6(h)(6)	Records of Conditions During Opacity/VE observations.	Keep records available and allow Administrator to inspect.	No.
§ 63.6(h)(7)(i)	Report continuous opacity monitoring system data monitoring data from performance test.	Submit continuous opacity monitoring system data with other performance test.	No.
§ 63.6(h)(7)(ii)	Using continuous opacity monitoring system instead of Method 9.	Can submit continuous opacity monitoring system data instead of Method 9 results even if rule requires Method 9, but must notify Administrator before performance test.	No.
§ 63.6(h)(7)(iii)	Averaging time for continuous opacity monitoring system during performance test.	To determine compliance, must reduce continuous opacity monitoring system data to 6-minute averages.	No.

TABLE 4 TO SUBPART UUUUU OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART UUUUU—Continued

Citation	Subject	Brief description	Comments
§ 63.6(h)(7)(iv)	Continuous opacity monitoring system requirements.	Demonstrate that continuous opacity monitoring system performance evaluations are conducted according to §§ 63.8(e), continuous opacity monitonng system are properly maintained and operated according to 63.8(c) and data quality as § 63.8(d).	No.
§ 63.6(h)(7)(v)	Determining Compliance with Opacity/VE Standards.	Continuous opacity monitoring system is probative but not conclusive evidence of compliance with opacity standard, even if Method 9 observation shows otherwise. Requirements for continuous opacity monitoring system to be probative evidence-proper maintenance, meeting PS 1, and data have not been altered.	No.
§ 63.6(h)(8)	Determining Compliance with Opacity/VE Standards.	Administrator will use all continuous opacity monitoring system, Method 9, and Method 22 results, as well as information about operation and maintenance to determine compliance.	No.
§ 63.6(h)(9)	Adjusted Opacity Standard	Procedures for Administrator to adjust an opacity standard.	No.
§ 63.6(i)(1)–(14)	Compliance Extension	Procedures and criteria for Administrator to grant compliance extension.	Yes.
§ 63.6(j)	Presidential Compliance Exemption	President may exempt source category from requirement to comply with rule.	Yes.
§ 63.7(a)(1)	Performance Test Dates	Dates for Conducting Initial Performance Testing and Other Compliance Demonstrations.	Yes.
§ 63.7(a)(2)(i)	Performance Test Dates	New source with initial startup date before effective date has 180 days after effective date to demonstrate compliance.	Yes.
§ 63.7(a)(2)(ii)	Performance Test Dates	New source with initial startup date after effective date has 180 days after initial startup date to demonstrate compliance.	Yes.
§ 63.7(a)(2)(iii)	Performance Test Dates	Existing source subject to standard established pursuant to 112(d) has 180 days after compliance date to demonstrate compliance.	Yes.
		AND	
		Existing source with startup date after effective date has 180 days after startup to demonstrate compliance.	Yes.
§ 63.7(a)(2)(iv)	Performance Test Dates	Existing source subject to standard established pursuant to 112(f) has 180 days after compliance date to demonstrate compliance.	No.
§ 63.7(a)(2)(v)	Performance Test Dates	Existing source that applied for extension of compliance has 180 days after termination date of extension to demonstrate compliance.	Yes.
§ 63.7(a)(2)(vi)	Performance Test Dates	New source subject to standard established pursuant to 112(f) that commenced construction after proposal date of 112(d) standard but before proposal date of 112(f) standard, has 180 days after compliance date to demonstrate compliance.	No.
§ 63.7(a)(2)(vii–viii)	[Reserved].		

TABLE 4 TO SUBPART UUUUU OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART UUUUU—Continued

Citation	Subject	Brief description	Comments
§ 63.7(a)(2)(ix)	Performance Test Dates	New source that commenced construction between proposal and promulgation dates, when promulgated standard is more stringent than proposed standard, has 180 days after effective date or 180 days after startup of source, whichever is later, to demonstrate compliance. AND If source initially demonstrates compliance with less stringent proposed standard, it has 3 years and 180 days after the effective date of the standard or 180 days after startup of source, whichever is later, to demonstrate compliance with promulgated standard.	Yes.
§ 63.7(a)(3)	Section 114 Authority	Administrator may require a performance test under Act Section 114 at any time.	Yes.
§ 63.7(b)(1)	Notification of Performance Test	Must notify Administrator 60 days before the test.	Yes.
§ 63.7(b)(2)	Notification of Rescheduling	If rescheduling a performance test is necessary, must notify Administrator 5 days before scheduled date of rescheduled date.	Yes.
§ 63.7(c)	Quality Assurance/Test Plan	Requirement to submit unit specific test plan 60 days before the test or on date Administrator agrees with: Test plan approval procedures AND Performance audit requirements AND Internal and External QA procedures for testing	Yes.
§ 63.7(d)	Testing Facilities	Requirements for testing facilities	Yes.
§ 63.7(e)(1)	Conditions for Conducting Performance Tests.	Perfomance tests must be conducted under representative conditions. AND	Yes.
		Cannot conduct performance tests during SSMs. AND	Yes.
		Not a deviation to exceed standard during SSM AND	Yes.
		Upon request of Administrator, make available records necessary to determine conditions of performance tests.	Yes.
§ 63.7(e)(2)	Conditions for Conducting Performance Tests.	Must conduct according to rule and EPA test methods unless Administrator approves alternative.	Yes.
§ 63.7(e)(3)	Test Run Duration	Must have three separate test runs AND Compliance is based on arithmetic mean of three runs AND Conditions when data from an additional test run can be used	Yes.
§ 63.7(f)	Alternative Test Method	Procedures by which Administrator can grant approval to use an alternative test method.	Yes.
§ 63.7(g)	Performance Test Data Analysis	Must include raw data in performance test report. AND Must submit performance test data 60 days after end of test with the Notification of Compliance Status AND Keep data for 5 years	Yes.
§ 63.7(h)	Waiver of Tests	Procedures for Administrator to waive performance test.	Yes.

TABLE 4 TO SUBPART UUUUU OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART UUUUU—Continued

Citation	Subject	Brief description	Comments
§ 63.7(a)(1)	Applicability of Monitoring Requirements	Subject to all monitoring requirements in standard.	Yes.
§ 63.8(a)(2)	Performance Specifications	Performance Specifications in appendix B of part 60 apply.	Yes.
§ 63.8(a)(3)	[Reserved].		
§ 63.8(a)(4)	Monitoring with Flares	Unless your rule says otherwise, the requirements for flares in § 63.11 apply.	No.
§ 63.8(b)(1)(i)–(ii)	Monitoring	Must conduct monitoring according to standard unless Administrator approves alternative.	Yes.
§ 63.8(b)(1)(iii)	Monitoring	Flares not subject to this section unless otherwise specified in relevant standard.	No.
§ 63.8(b)(2)–(3)	Multiple Effluents and Multiple Monitoring Systems.	Specific requirements for installing monitoring systems. AND Must install on each effluent before it is combined and before it is released to the atmosphere unless Administrator approves otherwise. AND If more than one monitoring system on an emission point, must report all monitoring system results, unless one monitoring system is a backup.	Yes.
§ 63.8(c)(1)	Monitoring System Operation and Maintenance.	Maintain monitoring system in a manner consistent with good air pollution control practices.	Yes.
§ 63.8(c)(1)(i)	Routine and Predictable SSM	Follow the SSM plan for routine repairs. Keep parts for routine repairs readily available. Reporting requirements for SSM when action is described in SSM plan.	Yes.
§ 63.8(c)(1)(ii)	SSM not in SSMP	Reporting requirements for SSM when action is not described in SSM plan.	Yes.
§ 63.8(c)(1)(iii)	Compliance with Operation and Maintenance Requirements.	How Administrator determines if source complying with operation and maintenance requirements. AND Review of source O&M procedures, records, Manufacturer's instructions, recommendations, and inspection of monitoring system.	Yes.
§ 63.8(c)(2)–(3)	Monitoring System Installation	Must install to get representative emission and parameter measurements. AND Must verify operational status before or at performance test.	Yes.
§ 63.8(c)(4)	Continuous Monitoring System (CMS) Requirements.	Continuous monitoring systems must be operating except during breakdown, out-of-control, repair, maintenance, and high-level calibration drifts.	Yes.
§ 63.8(c)(4)(i)	Continuous Monitoring System (CMS) Requirements.	Continuous opacity monitoring system must have a minimum of one cycle of sampling and analysis for each successive 10-second period and one cycle of data recording for each successive 6-minute period.	No.
§ 63.8(c)(4)(ii)	Continuous Monitoring System (CMS) Requirements.	Continuous emissions monitoring system must have a minimum of one cycle of operation for each successive 15-minute period.	Yes.
§ 63.8(c)(7)–(8)	Continuous monitoring systems Requirements.	Out-of-control periods, including reporting.	Yes.

TABLE 4 TO SUBPART UUUUU OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART UUUUU—Continued

Citation	Subject	Brief description	Comments
§ 63.8(d)	Continuous monitoring systems Quality Control.	Requirements for continuous monitoring systems quality control, including calibration, etc. AND Must keep quality control plan on record for the life of the affected source. Keep old versions for 5 years after revisions.	Yes.
§ 63.8(e)	Continuous monitoring systems Performance Evaluation.	Notification, performance evaluation test plan, reports.	Yes.
§ 63.8(f)(1)–(5)	Alternative Monitoring Method	Procedures for Administrator to approve alternative monitoring.	Yes.
§ 63.8(f)(6)	Alternative to Relative Accuracy Test	Procedures for Administrator to approve alternative relative accuracy tests for continuous emissions monitoring system.	No.
§ 63.8(g)(1)–(4)	Data Reduction	Continuous emissions monitoring system 1-hour averages computed over at least 4 equally spaced data points.	Yes.
§ 63.8(g)(5)	Data Reduction	Data that cannot be used in computing averages for continuous emissions monitoring system and continuous opacity monitoring system.	No.
§ 63.9(a)	Notification Requirements	Applicability and State Delegation	Yes.
§ 63.9(b)(1)–(5)	Initial Notifications	Submit notification 120 days after effective date. AND Notification of intent to construct/reconstruct AND Notification of commencement of construct/reconstruct; Notification of startup. AND Contents of each	Yes.
§ 63.9(c)	Request for Compliance Extension	Can request if cannot comply by date or if installed BACT/LAER.	Yes.
§ 63.9(d)	Notification of Special Compliance Requirements for New Source.	For sources that commence construction between proposal and promulgation and want to comply 3 years after effective date.	Yes.
§ 63.9(e)	Notification of Performance Test	Notify Administrator 60 days prior	Yes.
§ 63.9(f)	Notification of VE/Opacity Test	Notify Administrator 30 days prior	No.
§ 63.9(g)	Additional Notifications When Using Continuous Monitoring Systems.	Notification of performance evaluation AND Notification that exceeded criterion for relative accuracy	Yes.
§ 63.9(h)(1)–(6)	Notification of Compliance Status	Contents AND Due 60 days after end of performance test or other compliance demonstration When to submit to Federal vs. State authority	Yes.
§ 63.9(i)	Adjustment of Submittal Deadlines	Procedures for Administrator to approve change in when notifications must be submitted.	Yes.
§ 63.9(j)	Change in Previous Information	Must submit within 15 days after the change.	Yes.
§ 63.10(a)	Recordkeeping/Reporting	Applies to all, unless compliance extension. AND When to submit to Federal vs. State authority AND Procedures for owners of more than 1 source	Yes.

TABLE 4 TO SUBPART UUUUU OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART UUUUU—Continued

Citation	Subject	Brief description	Comments
§ 63.10(b)(1)	Recordkeeping/Reporting	General Requirements AND Keep all records readily available AND Keep for 5 years	Yes.
§ 63.10(b)(2)(i)–(v)	Records related to Startup, Shutdown, and Malfunction.	Occurrence of each of operation (process equipment). AND Occurrence of each malfunction of air pollution equipment AND Maintenance on air pollution control equipment AND Actions during startup, shutdown, and malfunction	Yes.
§ 63.10(b)(2)(vi) and (x–xi)	Continuous monitoring systems Records.	Malfunctions, inoperative, out-of-control AND Calibration checks AND Adjustments, maintenance	Yes.
§ 63.10(b)(2)(vii)–(ix)	Records	Measurements to demonstrate compliance with emissions limitations. AND Performance test and performance evaluation AND Measurements to determine conditions of performance test and performance evaluations.	Yes.
§ 63.10(b)(2)(xii)	Records	Records when under waiver	Yes.
§ 63.10(b)(2)(xiii)	Records	Records when using alternative to relative accuracy test.	Yes.
§ 63.10(b)(2)(xiv)	Records	All documentation supporting Initial Notification and Notification of Compliance Status.	Yes.
§ 63.10(b)(3)	Records	Applicability Determinations	Yes.
§ 63.10(c)(1)–(6), (9)–(15)	Records	Additional Records for continuous monitoring systems.	Yes.
§ 63.10(c)(7)–(8)	Records	Records of excess emissions and parameter monitoring exceedances for continuous monitoring systems.	Yes.
§ 63.10(d)(1)	General Reporting Requirements	Requirement to report	Yes.
§ 63.10(d)(2)	Report of Performance Test Results	When to submit to Federal or State authority.	Yes.
§ 63.10(d)(3)	Reporting Opacity or VE Observations	What to report and when	No.
§ 63.10(d)(4)	Progress Reports	Must submit progress reports on schedule if under compliance extension.	Yes.
§ 63.10(d)(5)	Startup, Shutdown, and Malfunction Reports.	Contents and submission	Yes.
§ 63.10(e)(1)–(92)	Additional continuous monitoring systems Reports.	Must report results for each CEM on a unit. AND Written copy of performance evaluation	Yes.
§ 63.10(e)(3)	Reports	Excess Emission Reports	No.
§ 63.10(e)(3)(i–iii)	Reports	Schedule for reporting excess emission and parameter monitor exceedance (now defined as deviations).	No.

TABLE 4 TO SUBPART UUUUU OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART UUUUU—Continued

Citation	Subject	Brief description	Comments
§ 63.10(e)(3)(iv–v)	Excess Emissions Reports	Requirement to revert to quarterly submission if there is an excess emissions and parameter monitor exceedance (now defined as deviations). AND Provision to request semiannual reporting after compliance for one year AND Submit report by 30th day following end of quarter or calendar half AND If there has not been an exceedance or excess emission (now defined as deviations), report contents is a statement that there have been no deviations	No.
§ 63.10(e)(3)(iv–v)	Excess Emissions Reports	Must submit report containing all of the information in § 63.10(c)(5–13), § 63.8(c)(7–8).	No.
§ 63.10(e)(3)(vi–viii)	Excess Emissions Report and Summary Report.	Requirements for reporting excess emissions for continuous monitoring systems (now called deviations).	No.
§ 63.10(e)(4)	Reporting continuous opacity monitoring system data.	Must submit continuous opacity monitoring system data with performance test data.	No.
§ 63.10(f)	Waiver for Recordkeeping Reporting	Procedures for Administrator to waive	Yes.
§ 63.11	Flares	Requirements for flares	No.
§ 63.12	Delegation	State authority to enforce standards	Yes.
§ 63.13	Addresses	Addresses where reports, notifications, and requests are sent.	Yes.
§ 63.14	Incorporation by Reference	Test methods incorporated by reference	Yes.
§ 63.15	Availability of Information	Public and confidential information	Yes.

APPENDIX B—PART 63

7. Appendix B to part 63 is amended by adding in numerical order new Method 324 to read as follows:

Method 324—Determination of Vapor Phase Flue Gas Mercury Emissions From Stationary Sources Using Dry Sorbent Trap Sampling

1.0 Introduction.

This method describes sampling criteria and procedures for the continuous sampling of mercury (Hg) emissions in combustion flue gas streams using sorbent traps. Analysis of each trap can be by cold vapor atomic fluorescence spectrometry (AF) which is described in this method, or by cold vapor atomic absorption spectrometry (AA). Only the AF analytical method is detailed in this method, with reference being made to other published methods for the AA analytical procedure. The Electric Power Research Institute has investigated the AF analytical procedure in the field with the support of ADA–ES and Frontier Geosciences, Inc. The AF procedure is based on EPA Method 1631, Revision E: Mercury in Water by Oxidation, Purge and Trap, and Cold Vapor Atomic Fluorescence Spectrometry. Persons using this method should have a thorough working knowledge of Methods 1, 2, 3, 4 and 5 of 40 CFR part 60, appendix A.

1.1 Scope and Application.

1.1.1 Analytes. The analyte measured by this method is total vapor-phase Hg, which represents the sum of elemental (CAS Number 7439–97–6) and oxidized forms of Hg, mass concentration (micrograms/dscm) in flue gas samples.

1.1.2 Applicability. This method is applicable to the determination of vapor-phase Hg concentrations ranging from 0.03 µg/dncm to 100 µg/dncm in low-dust applications, including controlled and uncontrolled emissions from stationary sources, only when specified within the regulations. When employed to demonstrate compliance with an emission regulation, paired sampling is to be performed as part of the method quality control procedure. The method is appropriate for flue gas Hg measurements from combustion sources. Very low Hg concentrations will require greater sample volumes. The method can be used over any period from 30 minutes to several days in duration, provided appropriate sample volumes are collected and all the quality control criteria in Section 9.0 are met. When sampling for periods greater than 12 hours, the sample rate is required to be maintained at a constant proportion to the total stack flowrate, ±25 percent to ensure representativeness of the sample collected.

2.0 Summary of Method.

Known volumes of flue gas are extracted from a duct through a single or paired sorbent traps with a nominal flow rate of 0.2 to 0.6 liters per minute through each trap. Each trap is then acid leached and the resulting leachate is analyzed by cold vapor atomic fluorescence spectrometry (CVAFS) detection. The AF analytical procedure is described in detail in EPA Method 1631. Analysis by AA can be performed by existing recognized procedures, such as that contained in ASTM Method D6784–02 (incorporated by reference, see § 63.14) or EPA Method 29.

3.0 Definitions. [Reserved]

4.0 Clean Handling and Contamination.

During preparation of the sorbent traps, as well as transport, field handling, sampling, recovery, and laboratory analysis, special attention must be paid to cleanliness procedures. This is to avoid Hg contamination of the samples, which generally contain very small amounts of Hg. For specifics on how to avoid contamination, Section 4 of Method 1631 should be well understood.

5.0 Safety.

5.1 Site hazards must be prepared for in advance of applying this method in the field. Suitable clothing to protect against site hazards is required, and requires advance coordination with the site to understand the conditions and applicable safety policies. At a minimum, portions of the sampling system will be hot, requiring appropriate gloves, long sleeves, and caution in handling this equipment.

5.2 Laboratory safety policies are to minimize risk of chemical exposure and to properly handle waste disposal. Personnel will don appropriate laboratory attire according to a Chemical Hygiene Plan established by the laboratory. This includes, but is not limited to, laboratory coat, safety goggles, and nitrile gloves under clean gloves.

5.3 The toxicity or carcinogenicity of reagents used in this method has not been fully established. The procedures required in this method may involve hazardous materials, operations, and equipment. This method may not address all of the safety problems associated with these procedures. It is the responsibility of the user to establish appropriate safety and health practices and determine the applicable regulatory limitations prior to performing these procedures. Each chemical should be regarded as a potential health hazard and exposure to these compounds should be minimized. Chemists should refer to the MSDS for each chemical with which they are working.

5.4 Any wastes generated by this procedure must be disposed of according to a hazardous materials management plan that details and tracks various waste streams and disposal procedures.

6.0 Equipment and Supplies.

6.1 Hg Sampling Train. A Schematic of a single trap sampling train used for this method is shown in Figure 324–1. Where this method is used to collect data to demonstrate compliance with a regulation, it must be performed with paired sorbent trap equipment.

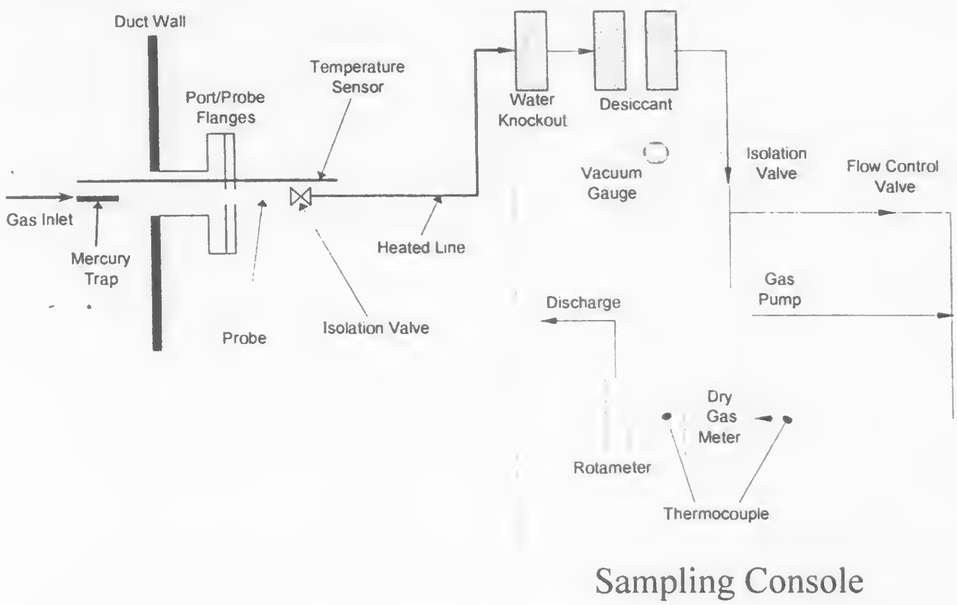


Figure 324–1. Hg Sampling Train Illustrating Single Trap.

6.1.1 Sorbent Trap. Use sorbent traps with separate main and backup sections in series for collection of Hg. Selection of the sorbent trap shall be based on: (1) Achievement of the performance criteria of this method, and (2) data is available to demonstrate the method can pass the criteria in EPA Method 301 when used in this method and when the results are compared with those from EPA Method 29, EPA Method 101A, or ASTM Method 6784–02 for the measurement of vapor-phase Hg in a similar flue gas matrix. Appropriate traps are referred to as "sorbent trap" throughout this method. The method requires the analysis of Hg in both main and backup portions of the sorbent within each trap. The sorbent trap should be obtained from a reliable source that has clean handling procedures in place for ultra low-level Hg analysis. This will help assure the low Hg environment required to manufacture sorbent traps with low blank levels of Hg. Sorbent trap sampling requirements or needed characteristics are shown in Table 324–1. Blank/cleanliness and other requirements are described in Table 324–2. The sorbent trap is supported on a probe and inserted directly into the flue gas stream, as shown on Figure 324–1. The sampled sorbent trap is the entire Hg sample.

6.1.2 Sampling Probe. The probe assembly shall have a leak-free attachment to the sorbent trap. For duct temperatures from 200 to 375°F, no heating is required. For duct temperatures less than 200°F, the sorbent tube must be heated to at least 200°F or higher to avoid liquid condensation in the sorbent trap by using a heated probe. For duct temperatures greater than 375°F, a large sorbent trap must be used, as shown in Table 324–1, and no heating is required. A thermocouple is used to monitor stack temperature.

6.1.3 Umbilical Vacuum Line. A 250°F heated umbilical line shall be used to convey to the moisture knockout the sampled gas that has passed through the sorbent trap and probe assembly.

6.1.4 Moisture Knockout. Impingers and desiccant can be combined to dry the sample gas prior to entering the dry gas meter. Alternative sample drying methods are acceptable as long as they do not affect sample volume measurement.

6.1.5 Vacuum Pump. A leak tight vacuum pump capable of delivering a controlled extraction flow rate between 0.1 to 0.8 liters per minute.

6.1.6 Dry Gas Meter. Use a dry gas meter that is calibrated according to the procedures in 40 CFR part 60, appendix A, Method 5, to measure the total sample volume collected. The dry gas meter must be sufficiently accurate to measure the sample volume within 2 percent, calibrated at the selected flow rate and conditions actually encountered during sampling, and equipped with a temperature sensor capable of measuring typical meter temperatures accurately to within 3°C (5.4°F).

6.2 Sample Analysis Equipment. Laboratory equipment as described in Method 1631, Sections 6.3 to 6.7 is required for analysis by AF. For analysis by AA, refer to Method 29 or ASTM Method 6784–02.

TABLE 324–1.—SORBENT TRAP AND SAMPLING REQUIREMENTS.

Item to be determined	Small sorbent trap	Large sorbent trap
Sampling Target: Hg Loading Range, µg	Minimum = 0.025 µg/trap Maximum = 150 µg/trap	Minimum = 0.10 µg/trap Maximum = 1800 µg/trap
Sampling Duration Required: limits on sample times.	Minimum = 30 minutes Maximum = 24 hours	Minimum = 24 hours Maximum = 10 days
Sampling Temperature Required	200 to 375°F	200 to 425°F
Sampling Rate Required	0.2 to 0.6 L/min; start at 0.4 L/min Must be constant proportion within +/− 25% if greater than 12 hours; constant rate within +/− 25 % if less than 12 hours.	0.2 to 0.6 L/min; start at 0.4 L/min Must be constant proportion of stack flowrate within +/− 25%

7.0 Analysis by AF, Reagents and Standards.

For analysis by AF, use Method 1631, Sections 7.1–7.3 and 7.5–7.12 for laboratory reagents and standards. Refer to Method 29 or ASTM Method 6784–02 for analysis by AA.

7.1 Reagent Water. Same as Method 1631, Section 7.1.

7.2 Air. Same as Method 1631, Section 7.2.

7.3 Hydrochloric Acid. Same as Method 1631, Section 7.3.

7.4 Stannous Chloride. Same as Method 1631, Section 7.5.

7.5 Bromine Monochloride (BrCl, 0.01N). Same as Method 1631, Section 7.6.

7.6 Hg Standards. Same as Method 1631, Sections 7.7 to 7.11.

7.7 Nitric Acid. Reagent grade, low Hg.

7.8 Sulfuric Acid. Reagent grade, low Hg.

7.9 Nitrogen. Same as Method 1631, Section 7.12.

7.10 Argon. Same as Method 1631, Section 7.13.

8.0 Sample Collection and Transport.

8.1 Pre-Test.

8.1.1 Site information should be obtained in accordance with Method 1 (40 CFR part 60, appendix A). Identify a location that has been shown to be free of stratification for SO_2 and NO_X through concentration measurement traverses for those gases. An estimation of the expected Hg concentration is required to establish minimum sample volumes. Based on estimated minimum sample volume and normal sample rates for each size trap used, determine sampling duration with the data provided in Table 324–1.

8.1.2 Sorbent traps must be obtained from a reliable source such that high quality control and trace cleanliness are maintained. Method detection limits will be adversely affected if adequate cleanliness is not maintained. Sorbent traps should be handled only with powder-free low Hg gloves (vinyl, latex, or nitrile are acceptable) that have not touched any other surface. The sorbent traps should not be removed from their clean storage containers until after the preliminary leak check has been completed. Field efforts at clean handling of the sorbent traps are key to the success of this method.

8.1.3 Assemble the sample train according to Figure 324–1, except omit the sorbent trap.

8.1.4 Preliminary Leak Check. Perform system leak check without the single or dual sorbent traps in place. This entails plugging the end of the probe to which each sorbent trap will be affixed, and using the vacuum pump to draw a vacuum in each sample train. Adjust the vacuum in the sample train to 15 inches Hg. A rotameter on the dry gas meter will indicate the leakage rate. The leakage rate must be less than 2 percent of the planned sampling rate.

8.1.5 Release the vacuum in the sample train, turn off the pump, and affix the sorbent trap to the end of the probe, using clean handling procedures. Leave the flue gas end of the sorbent trap plugged.

8.1.6 Pre-test Leak Check. Perform a leak check with the Sorbent trap in place. Use the sampling vacuum pump to draw a vacuum in the sample train. Adjust the vacuum in the sample train to 15 inches Hg. A rotameter on the dry gas meter will indicate the leakage rate. Record the leakage rate. The leakage rate must be less than 2 percent of the planned sampling rate. Once the leak check passes this criterion, carefully release the vacuum in the sample train (the sorbent trap must not be exposed to abrupt changes in pressure or to backflow), then re-cap the flue gas end of the sorbent trap until the probe is ready for insertion. The sorbent trap packing beds must be undisturbed by the leak test to prevent gas channeling through the media during sampling.

8.1.7 Use temperature controllers to heat the portions of the trains that require it. The sorbent trap must be maintained between 200 and 375 °F during sampling.

8.1.8 Gas temperature and static pressure must be considered prior to sampling in order to maintain proper safety precautions during sampling.

8.2 Sample Collection.

8.2.1 Remove the plug from the end of a sorbent trap and store it in a clean sorbent trap storage container. Remove the sample duct port cap and insert the probe. Secure the probe and ensure that no leakage occurs between the duct and environment.

8.2.2 Record initial data including the start time, starting dry gas meter readings, and the name of the field tester(s). Set the initial sample flow rate to 0.4 L/min (+/− 25 percent).

8.2.3 For constant-flow sampling (samples less than 12 hours in duration), every 10–15 minutes during the sampling period: record the time, the sample flow rate, the gas meter readings, the duct temperature, the flow meter temperatures, temperatures of heated equipment such as the vacuum lines and the probes (if heated), and the sampling vacuum reading. Adjust the sample rate as needed, maintaining constant sampling within +/− 25 percent of the initial reading.

8.2.4 For constant proportion sampling (samples 12 hours or greater in duration), every hour during the sampling period: record the time, the sample flow rate, the gas meter readings, the duct temperature, the flow meter temperatures, temperatures of heated equipment such as the vacuum lines and the probes (if heated), and the sampling vacuum readings. Also record the stack flow rate reading, whether provided as a CEM flow monitor signal, a pitot probe or other direct flow indication, or a plant input signal. Adjust the sampling rate to maintain proportional sampling within +/− 25 percent relative to the total stack flowrate.

8.2.5 Obtain and record operating data for the facility during the test period, including total stack flowrate and the oxygen concentration at the flue gas test location. Barometric pressure must be obtained for correcting sample volume to standard conditions.

8.2.6 Post Test Leak Check. When sampling is completed, turn off the sample pump, remove the probe from the port and carefully re-plug the end of the sorbent trap. Perform leak check by turning on the sampling vacuum pumps with the plug in place. The rotameter on the dry gas meters will indicate the leakage rates. Record the leakage rate and vacuum. The leakage rate must be less than 2 percent of the actual sampling rate. Following the leak check, carefully release the vacuum in the sample train.

8.2.7 Sample Recovery. Recover each sampled sorbent trap by removing it from the probe, plugging both ends with the clean caps provided with the sorbent trap, and then wiping any dirt off the outside of the sorbent trap. Place the sorbent trap into the clean sample storage container in which it was provided, along with the data sheet that includes the post-test leak check, final volume, and test end time.

8.3 Quality Control Samples and Requirements.

8.3.1 Field blanks. Refer to Table 324–2.

8.3.2 Duplicate (paired or side by side) samples. Refer to Section 8.6.6 of Performance Specification 12A of 40 CFR part 60, appendix B for this criteria.

8.3.3 Breakthrough performance data ("B" bed in each trap, or second traps behind). Refer to Table 324–2.

8.3.4 Field spikes (sorbent traps spiked with Hg in the lab and periodically sampled in the field to determine overall accuracy). Refer to Table 324–2.

8.3.5 Laboratory matrix and matrix spike duplicates. Refer to Table 324–2.

9.0 Quality Control.

Table 324–2 summarizes the major quantifiable QC components.

TABLE 324–2.—QUALITY CONTROL FOR SAMPLES

QA/QC specification	Acceptance criteria	Frequency	Corrective action
Leak-check	<2% of sampling rate	Pre and post-sampling	Pre-sampling: repair leak. Post-sampling: Flag data and repeat run if for regulatory compliance.
Sample Flow Rate for samples less than 12 hours in duration.	0.4 L/min initially and +/− 25% of initial rate throughout run.	Throughout run every 10–15 minutes.	Adjust when data is recorded.
Sample Flow Rate for samples greater than 12 hours in duration.	0.4 L/min initially and maintain +/ − 25% of ratio to flue gas flow rate throughout sampling.	Throughout run every hour	Adjust when data is recorded.
Sorbent trap laboratory blank (same lot as samples).	<5 ng/trap and a standard deviation of <1.0 ng/trap (n=3).	3 per analysis set of 20 sorbent traps.	
Sorbent trap field blank (same lot as samples).	<5 ng/trap and a standard deviation of <1.0 ng/trap (n=3) OR <5% of average sample collected.	1 per every 10 field samples collected.	
B-Trap Bed Analysis	<2% of A-Trap Bed Value OR < 5 ng/trap.	Every sample	
Paired Train Results	Same as Section 8.6.6 of PS–12A of 40 CFR Part 60, Appendix B.		
Field Spikes	80% to 120% recovery	For long-term regulatory monitoring, 1 per every 3 samples for the first 12 samples.	If the first 4 field spikes do not meet the +/− 20% criteria, take corrective sampling and laboratory measures and repeat at the 1 per every 3 sample rate until the +/− 20% criteria is met.
Laboratory matrix and matrix spike duplicates.	85% to 115% recovery	1 per every 10 or 20 samples—to be determined.	

10.0 Calibration and Standards.

Same as Sections 10.1, 10.2 and 10.4 of Method 1631.

10.1 Calibration and Standardization. Same as Sections 10.1 and 10.4 of Method 1631.

10.2 Bubbler System. Same as Section 10.2 of M1631.

10.3 Flow-Injection System. Not applicable.

11.0 Analytical Procedures.

11.1 *Preparation Step.* The sorbent traps are received and processed in a low-Hg environment (class-100 laminar-flow hood and gaseous Hg air concentrations below 20 ng/m^3) following clean-handling procedures. Any dirt or particulate present on the exterior of the trap must be removed to avoid contamination of the sample. The sorbent traps are then opened and the sorbent bed(s) transferred to an appropriate sized trace-clean vessel. It is recommended that the height of the trace-clean vessel be at least 3 times the diameter to facilitate a refluxing action.

11.2 Leaching Step. The sorbent trap is then subjected to a hot-acid leach using a 70:30 ratio mixture of concentrated HNO_3/H_2SO_4. The acid volume must be 40 percent of the expected end volume of the digest after dilution. The HNO_3/H_2SO_4 acid to carbon ratio should be approximately 35:1. The leachate is then heated to a temperature of 50 to 60°C for 1.5 to 2.0 hours in the finger-tight capped vessels. This process may generate significant quantities of noxious and corrosive gasses and must only be performed in a well-ventilated fume hood. Care must be taken to prevent excessive heated leaching of the samples as this will begin to break down the charcoal material.

11.3 Dilution Step. After the leached samples have been removed from the hot plate and allowed to cool to room temperature, they are brought to volume with a 5 percent (v/v) solution of 0.01 N BrCl. As the leaching digest contains a substantial amount of dissolved gasses, add the BrCl slowly, especially if the samples are still warm. As before, this procedure must be performed in a properly functioning fume hood. The sample is now ready for analysis.

11.4 Hg Reduction and Purging. (Reference Section 11.2 of M1631 except that NH2OH is not used.)

11.4.1 Bubbler System. Pipette an aliquot of the digested sample into the bubbler containing pre-blanked reagent water and a soda lime trap connected to the exhaust port. Add stannous chloride ($SnCl_2$) to reduce the aliquot and then seal the bubbler. Connect gold sample traps to the end of the soda lime trap as shown in Figures 1 and 2 of Method 1631. Finally, connect the N_2 lines and purge for 20 minutes. The sample trap can then be added into the analytical train. M1631, Section 11.2.1.

11.4.2 Flow Injection System. If required.

11.5 Desorption of Hg from the gold trap, and peak evaluation. Use Section 11.3 and 11.4 in M1631.

11.6 Instrument Calibration. Analyze the standards by AA or AF following the guidelines specified by the instrument manufacturer. Construct a calibration curve by plotting the absorbances of the standards versus µg/l Hg. The R^2 for the calibration curve should be 0.999 or better. If the curve does not have an R^2 value equal to or better than 0.999 then the curve should be rerun. If the curve still does not meet this criteria then new standards should be prepared and the instrument recalibrated. All calibration points contained in the curve must be within 10 percent of the calibration value when the calibration curve is applied to the calibration standards.

11.7 Sample Analysis. Analyze the samples in duplicate following the same procedures used for instrument calibration. From the calibration curve, determine sample Hg concentrations. To determine total Hg mass in each sample fraction, refer to calculations in Section 15. Record all sample dilutions.

11.8 Continued Calibration Performance. To verify continued calibration performance, a continuing calibration check standard should be run every 10 samples. The measured Hg concentration of the continuing calibration check standard must be within 10 percent of the expected value.

11.9 Measurement Precision. The QA/QC for the analytical portion of this method is that every sample, after it has been prepared, is to be analyzed in duplicate with every tenth sample analyzed in triplicate. These results must be within 10 percent of each other. If this is not the case, then the instrument must be recalibrated and the samples reanalyzed.

11.10 Measurement Accuracy. Following calibration, an independently prepared standard (not from same calibration stock solution) should be analyzed. In addition, after every ten samples, a known spike sample (standard addition) must be analyzed.

The measured Hg content of the spiked samples must be within 10 percent of the expected value.

11.11 Independent QA/QC Checks. It is suggested that the QA/QC procedures developed for a test program include submitting, on occasion, spiked Hg samples to the analytical laboratory by either the prime contractor, if different from the laboratory, or an independent organization. The measured Hg content of reference samples must be within 15 percent of the expected value. If this limit is exceeded, corrective action (*e.g.*, re-calibration) must be taken and the samples re-analyzed.

11.12 Quality Assurance/Quality Control. For this method, it is important that both the sampling team and analytical people be very well trained in the procedures. This is a complicated method that requires a high-level of sampling and analytical experience. For the sampling portion of the QA/QC procedure, both solution and field blanks are required. It should be noted that if high-quality reagents are used and care is taken in their preparation and in the train assembly, there should be little, if any, Hg measured in either the solution or field blanks.

11.13 Solution Blanks. Solution blanks must be taken and analyzed every time a new batch of solution is prepared. If Hg is detected in these solution blanks, the concentration is subtracted from the measured sample results. The maximum amount that can be subtracted is 10 percent of the measured result or 10 times the detection limit of the instrument which ever is lower. If the solution blanks are greater than 10 percent the data must be flagged as suspect.

11.14 Field Blanks. A field blank is performed by assembling a sample train, transporting it to the sampling location during the sampling period, and recovering it as a regular sample. These data are used to ensure that there is no contamination as a result of the sampling activities. A minimum of one field blank at each sampling location must be completed for each test site. Any Hg detected in the field blanks cannot be subtracted from the results. Whether or not the Hg detected in the field blanks is significant is determined based on the QA/QC procedures established prior to the testing. At a minimum, if field blanks exceed 30 percent of the measured value at the corresponding location, the data must be flagged as suspect.

12.0 Calculations and Data Analysis.

Use Section 12 in M1631.

13.0 Constant Proportion Sampling.

Calculate the Sample Rate/Stack Flow = “x.” “X” must be maintained within 0.75 “x” to 1.25 “x” for sampling times in excess of 12 hours. For mass emission rate calculations, use the flow CEM total measured flow corresponding to the sorbent trap sample time period.

14.0 Sampling and Data Summary Calculations.

Refer to 40 CFR part 60, appendix A, Methods 2, 4, and 5 for example calculations.

15.0 Pollution Prevention.

Refer to Section 13 in Method 1631.

16.0 Waste Management.

Refer to Section 14 in Method 1631.

17.0 Bibliography.

17.1 EPA Method 1631, Revision E “Mercury in Water by Oxidation, Purge and Trap, and Cold Vapor Atomic Fluorescence Spectrometry,” August 2002.

17.2 “Comparison of Sampling Methods to Determine Total and Speciated Mercury in Flue Gas,” CRADA F00–038 Final Report, DOE/NETL–2001/1147, January 4, 2001.

17.3 40 CFR part 60, appendix A, “Method 29—Determination of Metals Emissions from Stationary Sources.”

17.4 40 CFR part 60, appendix B, “Performance Specification 12A, Specification and Test Procedures for Total Vapor Phase Mercury Continuous Emission Monitoring Systems in Stationary Sources.”

17.5 ASTM Method D6784–02, “Standard Test Method for Elemental, Oxidized, Particle-bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method).”

Option 2—Proposed Amendments to Parts 60 and 63

PART 60—[AMENDED]

1. The authority citation for part 60 continues to read as follows:

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

2. Section 60.17 is amended by adding paragraph (a)(65) to read as follows:

§ 60.17 Incorporations by Reference.

* * * * *

(a) * * *

(65) ASTM D6784–02, Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), for appendix B to part 60, Performance Specification 12A.

* * * * *

Subpart Da—[Amended]

3. Subpart Da is amended by:

a. Redesignate § 60.49a as § 60.51a;
b. Redesignate § 60.48a as § 60.50a;
c. Redesignate § 60.47a as § 60.49a;
d. Redesignate § 60.46a as § 60.48a;
e. Redesignate § 60.45a as § 60.47a; and
f. Adding new §§ 60.45a and 60.46a to read as follows:

§ 60.45a Standard for Mercury

(a) For each coal-fired electric utility steam generating unit other than an integrated gasification combined cycle (IGCC) electric utility steam generating unit, you must meet each mercury (Hg) emissions limit in paragraphs (a)(1) through (5) of this section that applies to you. The Hg emissions limits in paragraphs (a)(1) through (5) of this section are based on a 12-month rolling average using the procedures in § 60.50a(h).

(1) For each coal-fired electric utility steam generating unit that burns only bituminous coal, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 6.0×10^{-6} pound per Megawatt hour (lb/MWh) or 0.0060 lb/gigawatt-hour (GWh) on an output basis. The SI equivalent is 0.00075 nanograms per joule (ng/J).

(2) For each coal-fired electric utility steam generating unit that burns only subbituminous coal, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 20×10^{-6} lb/MWh or 0.020 lb/GWh on an output basis. The SI equivalent is 0.0025 ng/J.

(3) For each coal-fired electric utility steam generating unit that burns only lignite, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 62×10^{-6} lb/MWh or 0.062 lb/GWh on an output basis. The SI equivalent is 0.0078 ng/J.

(4) For each coal-burning electric utility steam generating unit that burns only coal refuse, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 1.1×10^{-6} lb/MWh or 0.0011 lb/GWh on an output basis. The SI equivalent is 0.00087 ng/J.

(5) For each coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks (*i.e.*, bituminous coal, subbituminous coal, lignite) or a blend of coal and coal refuse, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of the monthly unit-specific Hg emissions limit established according to paragraph (a)(5)(i) or (ii) of this section, as applicable to your unit.

(i) If you operate a coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks or a blend of coal and coal refuse, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of the computed weighted Hg emissions limit based on the proportion of energy output (in Btu) contributed by each coal-rank burned during the compliance period and its applicable Hg emissions limit in paragraphs (a)(1) through (4) of this section as determined using Equation 1 of this section. You must meet the weighted Hg emissions limit calculated using Equation 1 of this section by calculating the unit emission rate based on the total Hg loading of the unit and the total Btu or megawatt hours contributed by all fuels burned during the compliance period.

$$EL_b = \frac{\sum_{i=1}^{n} EL_i (HH_i)}{\sum_{i=1}^{n} HH_i} \quad \text{(Eq. 1)}$$

Where:

EL_b = Total allowable Hg in lb/MWh that can be emitted to the atmosphere from any affected source being averaged under the blending provision.

EL_i = Hg emissions limit for the subcategory that applies to affected source i, lb/MWh.

HH_i = Electricity output from affected source i during the production period related to the corresponding H_i that falls within the compliance period, gross MWh generated by the electric utility steam generating unit.

n = Number of coal ranks being averaged for an affected source.

(ii) If you operate a coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks or a blend of coal and coal refuse together with one or more non-regulated, supplementary fuels, you must not discharge into the atmosphere any gases from the unit that contain Hg in excess of the computed weighted Hg emission limit based on the proportion of electricity output (in MWh) contributed by each coal rank burned during the compliance period and its applicable Hg emissions limit in paragraphs (a)(1) through (4) of this section as determined using Equation 1 of this section. You must meet the weighted Hg emissions limit calculated using Equation 1 of this section by calculating the unit emission rate based on the total Hg loading of the unit and the total megawatt hours contributed by both regulated and nonregulated fuels burned during the compliance period.

(b) For each IGCC electric utility steam generating unit, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 20×10^{-6} lb/MWh or 0.020 lb/GWh on an output basis. The SI equivalent is 0.0025 ng/J. This Hg emissions limit is based on a 12-month rolling average using the procedures in § 60.50a(g).

§ 60.46a Standard for Nickel

(a) On and after the date on which the initial performance test required to be conducted under § 60.8 is completed, the owner or operator of each oil-fired unit subject to the provisions of this subpart shall not discharge into the atmosphere any gases from an oil-fired electric utility steam generating unit which contain Ni in excess of 0.0008 lb/MWh on an output basis. The SI equivalent is 0.010 ng/J.

(b) The emissions limit for an oil-fired electric utility steam generating unit in paragraph (a) of this section does not apply if the owner or operator uses distillate oil as fuel. Except as noted in paragraph (e) of this section, the emissions limit in paragraph (a) of this section will apply immediately if the owner or operator subsequently uses a fuel other than distillate oil.

(c) If you use an ESP to meet a Ni emissions limit in this subpart, you must operate the ESP such that the hourly average voltage and secondary current (or total power input) do not fall below the limit established in the initial or subsequent performance test.

(d) If you use a control device or combination of control devices other than an ESP to meet the Ni emissions limit, or you wish to establish and monitor an alternative operating limit and alternative monitoring parameters for an ESP, you must apply to the Administrator for approval of alternative monitoring under § 60.13(i).

(e) If you comply with the requirements in § 60.46a(b) for switching fuel, and you must switch fuel because of an emergency, you must notify the Administrator in writing within 30 days of using a fuel other than distillate oil.

4. Newly redesignated § 60.48a is amended by:

a. Revising paragraph (c);

b. In paragraph (h) by revising the existing references from "§ 60.47a" to "§ 60.49a";

c. In paragraph (i) by revising the existing references for "§§ 60.47a(c)," "60.47a(l)," and "60.47a(k)" to "§§ 60.49a(c)," "60.49a(l)," and "60.49a(k)," respectively;

d. In paragraph (j)(2) by revising the existing references from "§ 60.47a" to "§ 60.49a" twice;

e. In paragraph (k)(2)(ii) by revising the existing references from "§ 60.47a" and "60.47a(l)" to "§ 60.49a" and "60.49a(l)," respectively; in paragraph (k)(2)(iii) by revising the existing references from "§ 60.47a(k)" to "§ 60.49a(k)"; and in paragraph (k)(2)(iv) by revising the existing references from "§ 60.47a(l)" to "§ 60.49a(l)"; and

f. Adding new paragraphs (m) and (n).

The revision and additions read as follows:

§ 60.48a Compliance provisions.

* * * * *

(c) The particulate matter emission standards under § 60.42a, the nitrogen oxides emission standards under § 60.44a, the Hg emission standards under § 60.45a, and the Ni emission standards under § 60.46a apply at all times except during periods of startup, shutdown, or malfunction.

* * * * *

(m) *Compliance provisions for sources subject to § 60.45a.* The owner or operator of an affected facility subject to § 60.45a (new sources constructed after January 30, 2004) shall calculate Hg emissions by multiplying the average hourly Hg output concentration measured according to the provisions of § 60.49a(c) by the average hourly flow rate measured according to the provisions of § 60.49a(l) and divided by the average hourly gross heat rate measured according to the provisions in § 60.49a(k).

(n) *Compliance provisions for sources subject to § 60.46a.* (1) The owner or operator of an affected facility subject to § 60.46a(a) (new source constructed after January 30, 2004) shall calculate Ni emissions rate according to the procedures outlined in § 60.50a(i).

5. Newly redesignated § 60.49a is amended by:

a. In paragraph (c)(2) by revising the existing references from "§ 60.49a" to "§ 60.51a" twice;

b. In paragraph (g) by revising the existing reference from "§ 60.46a" to "§ 60.48a."

c. Revising paragraph (k) introductory text; and

d. Adding new paragraphs (p) through (s).

The revision and additions read as follows:

§ 60.49a Emission monitoring.

* * * * *

(k) The procedures specified in paragraphs (k)(1) through (3) of this section shall be used to determine compliance with the output-based standards under §§ 60.42a(c), 60.43a(i), 60.44a(d)(1), 60.44a(e), 60.45a, and 60.46a.

* * * * *

(p) The owner or operator of an affected facility demonstrating compliance with an Hg limit in § 60.45a shall install and operate a continuous emissions monitoring system (CEMS) to measure and record the concentration of Hg in the exhaust gases from each stack according to the requirements in paragraphs (p)(1) through (3) of this section.

(1) The owner or operator must install, operate, and maintain each CEMS according to Performance Specification 12A in 40 CFR part 60, appendix B.

(2) The owner or operator must conduct a performance evaluation of

each CEMS according to the requirements of § 60.13 and Performance Specification 12A in 40 CFR part 60, appendix B.

(3) The owner or operator must operate each CEMS according to the requirements in paragraphs (p)(3)(i) through (iv) of this section.

(i) As specified in § 60.13(e)(2), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(ii) The owner or operator must reduce CEMS data as specified in § 60.13(h).

(iii) Each CEMS must determine and record the 1-hour average emissions using all the hourly averages collected for periods during which the CEMS is not out of control.

(iv) The owner or operator must record the results of each inspection, calibration, and validation check.

(4) Mercury CEMS data collection must conform to paragraphs (p)(4)(i) through (iv) of this section.

(i) A complete day of data for continuous monitoring is 18 hours or more in a 24-hour period.

(ii) A complete month of data for continuous monitoring is 21 days or more in a calendar month.

(iii) If you collect less than 21 days of continuous emissions data, you must discard the data collected that month and replace the data with the mean of the individual monthly emission rate values determined in the last 12 months.

(iv) If you collect less than 21 days per monthly period of continuous data again in that same 12-month rolling average cycle, you must discard the data collected that month and replace that data with the highest individual monthly emission rate determined in the last 12 months.

(q) As an alternative to the CEMS required in paragraph (p) of this section, the owner or operator must monitor Hg emissions using Method 324 in 40 CFR part 63, appendix A.

(r) The owner or operator of an affected facility which uses an ESP to meet a Ni limit in § 60.46a shall install and operate a continuous parameter monitoring system (CPMS) to measure and record the voltage and secondary current (or total power input) to the control device according to the requirements in paragraphs (r)(1) through (3) of this section.

(1) Each CPMS must complete a minimum of one cycle of operation for each successive 15-minute period. The owner or operator must have a minimum of four successive cycles of operation to have a valid hour of data.

(2) Each CPMS must determine the 1-hour block average of all recorded readings.

(3) The owner or operator must record the results of each inspection, calibration, and validation check for a CPMS.

(s) The owner or operator shall prepare and submit to the Administrator for approval a unit-specific monitoring plan for each monitoring system. The owner or operator shall comply with the requirements in your plan. The plan must address the requirements in paragraphs (s)(1) through (6) of this section.

(1) Installation of the CMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (*e.g.*, on or downstream of the last control device);

(2) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems;

(3) Performance evaluation procedures and acceptance criteria (*e.g.*, calibrations);

(4) Ongoing operation and maintenance procedures in accordance with the general requirements of § 60.13(d);

(5) Ongoing data quality assurance procedures in accordance with the general requirements of § 60.13; and

(6) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of § 60.7.

6. Newly redesignated § 60.50a is amended by:

a. In paragraph (c)(5) by revising the existing references from "§ 60.47a(b) and (d)" to "§ 60.49a(b) and (d)," respectively;

b. In paragraph (d)(2) by revising the existing references from "§ 60.47a(c) and (d)" to "§ 60.49a(c) and (d)," respectively;

c. In paragraph (e)(2) by revising the existing reference from "§ 60.46a(d)(1)" to "§ 60.48a(d)(1)"; and

d. Adding new paragraphs (g) through (j).

The additions read as follows:

§ 60.50a Compliance determination procedures and methods.

* * * * *

(g) For the purposes of determining compliance with the emission limits in §§ 60.45a and 60.46a, the owner or operator of an electric utility steam generating unit which is also a cogeneration unit shall use the procedures in paragraphs (g)(1) and (2) of this section to calculate emission rates based on electrical output to the grid plus half of the equivalent electrical energy in the unit's process stream.

(1) All conversions from Btu/hr unit input to MWe unit output must use equivalents found in 40 CFR 60.40(a)(1) for electric utilities (*i.e.*, 250 million Btu/hr input to an electric utility steam generating unit is equivalent to 73 MWe input to the electric utility steam generating unit); 73 MWe input to the electric utility steam generating unit is equivalent to 25 MWe output from the boiler electric utility steam generating unit; therefore, 250 million Btu input to the electric utility steam generating unit is equivalent to 25 MWe output from the electric utility steam generating unit).

(2) Use the Equation 1 of this section to determine the cogeneration Hg or Ni emission rate over a specific compliance period.

$$ER_{cogen} = \frac{E}{\left(\left(V_{grid}\right)+\left(\frac{V_{process}}{2}\right)\right)} \quad \text{(Eq. 1)}$$

Where:

ER_{cogen} = Cogeneration Hg or Ni emission rate over a compliance period in lb/MWh;

E = Mass of Hg or Ni emitted from the stack over the same compliance period (lb);

V_{grid} = Amount of energy sent to the grid over the same compliance period (MWh); and

$V_{process}$ = Amount of energy converted to steam for process use over the same compliance period (MWh).

(h) The owner or operator shall determine compliance with the Hg limit in § 60.45a according to the procedures in paragraphs (h)(1) through (3) of this section.

(1) The owner or operator shall demonstrate compliance by calculating the arithmetic average of all weekly emission rates for Hg for the 12 successive calendar months, except for data obtained during startup, shutdown, or malfunction.

(2) If a CEMS is used to demonstrate compliance, follow the procedures in paragraphs (h)(2)(i) through (ii) of this section to determine the 12-month rolling average.

(i) Calculate the total mass of Hg emissions over a month (M), in micrograms (μg), using Equation 2 of this section.

$$M = \int_0^t C(t)V(t)dt \qquad \text{(Eq. 2)}$$

Where:

M = Total mass of Hg emissions, (μg);

C = Concentration of Hg recorded by CEMS per Performance Specification 12A (40 CFR part 60, appendix B), micrograms per dry standard cubic meter (μg/dscm);

V = Volumetric flow rate recorded at the same frequency as the CEMS reading for the Hg concentration indicated in PS–12A, cubic meters per hour (dscm/hr); and

t = total time period over which mass measurements are collected, (hr).

(ii) Calculate the Hg emission rate for an output-based limit (lb/hr) using Equation 3 of this section:

$$ER = \frac{M \times \text{conversion factor}}{TP_{\text{output-based}}} \qquad \text{(Eq. 3)}$$

Where:

ER = Hg emission rate, (lb/hr);

M = Total mass of Hg emissions, (μg);

Conversion factor = 2.205×10^{-9}; and

$TP_{\text{output-based}}$ = Total power, megawatt-hours (MWh).

(3) If you use Method 324 (40 CFR part 63, appendix B), determine the 12-month rolling average Hg emission rate according to the applicable procedures in paragraphs (h)(3)(i) through (iv) of this section.

(i) Sum the Hg concentrations for the emission rate period, (μg/dscm).

(ii) Calculate the total volumetric flow rate for the emission rate period, (dscm).

(iii) Multiply the total Hg concentration times the total volumetric rate to obtain the total mass of Hg for the emission rate period in micrograms.

(iv) Calculate the Hg emission rate for an output-based limit (lb/hr) using Equation 3 of this section.

(i) The owner or operator shall determine compliance with the Ni limit in § 60.46a according to the procedures in paragraphs (i)(1) through (2) of this section.

(1) Ni emissions concentration for compliance under § 60.46a is determined by the three-run average (nominal 1-hour runs) by Method 29 of 40 CFR part 60, Appendix A, for the initial and subsequent performance tests.

(2) Use the applicable procedures in paragraphs (2)(i) through (v) of this section to convert the Method 29 Ni emissions measurement to the output-based format for comparison to the § 60.46a Ni emission limit.

(i) Sum the Ni concentrations obtained from the Method 29 test runs, milligrams per dscm (mg/dscm).

(ii) Calculate the total volumetric flow rate obtained during the Method 29 test runs, (dscm).

(iii) Multiply the total Ni concentration times the total volumetric flow rate for the duration of the initial compliance testing period to obtain the total mass of Ni in milligrams.

(iv) Calculate the output-based Ni emissions rate in a lb/ format using Equation 4 of this section.

$$ER = \frac{M \times \text{conversion factor}}{TP_{\text{output-based}}} \qquad \text{(Eq. 4)}$$

Where:

ER = Ni emission rate, (lb/hr);

M = Total mass of Ni emissions, (mg);

Conversion factor = 2.205×10^{-6}; and

$TP_{\text{output-based}}$ = Total power, (MWh).

(3) Compliance with the Ni emission limits under § 60.46a is determined by the three-run average (nominal 1-hour runs) by Method 29 for the initial and subsequent performance tests.

(j) Quarterly accuracy determinations and daily calibration drift tests for gaseous Hg CEMS shall be performed in accordance with Procedure 1 (appendix F of 40 CFR part 60). Annual RATAs for Hg sorbent trap monitoring systems shall also be performed in accordance with Procedure 1.

7. Newly redesignated § 60.51a is amended by:

a. Revising paragraph (a);

b. In paragraph (c) introductory text by revising the existing references from "§ 60.47a" and "§ 60.46a(h)" to "§ 60.49a" and "§ 60.48a(h)," respectively;

c. In paragraph (d)(1) by revising the existing reference from "§ 60.46a(d)" to "§ 60.48a(d)"; and

d. In paragraph (e)(1) by revising the existing reference from "§ 60.48a" to "§ 60.50a."

The revisions and additions read as follows:

§ 60.51a Reporting requirements.

(a) For sulfur dioxide, nitrogen oxides, particulate matter, Hg, and Ni emissions, the performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors (including the transmissometer) are submitted to the Administrator.

* * * * *

8. Section 60.52a is added to read as follows:

§ 60.52a Recordkeeping Requirements

The owner or operator of an affected facility subject to the emissions limitations in § 60.45a or § 60.46a shall maintain records of all information needed to demonstrate compliance including performance tests, monitoring data, fuel analyses, and calculations.

Subpart GGGG—[Added]

9. Part 60 is amended by adding subpart GGGG to read as follows:

Subpart GGGG—Emission Guidelines and Compliance Times for Oil-fired Electric Utility Steam Generating Units

§ 60.4000 Scope

This subpart contains emission guidelines and compliance times for the control of certain designated pollutants from certain designated electric utility steam generating units in accordance with section 111(d) of the Act and subpart B of this part.

§ 60.4005 Definitions

Terms used but not defined in this subpart have the meaning given them in the Act and in subparts A, B, and Da of this part.

§ 60.4010 Designated Facilities

(a) The designated facility to which the emission guidelines apply is each existing electric utility steam generating unit for which construction, reconstruction or modification was commenced before January 30, 2004.

(b) Physical or operational changes made to an existing electric utility steam generating unit solely to comply with an emission guideline are not considered a modification or reconstruction and would not subject an existing electric utility steam generating unit to the requirements of subpart Da (*see* § 60.40a of subpart Da).

§ 60.4015 Emission Guidelines for Oil-fired Electric Utility Steam Generating Units

For approval, a State plan shall include emission limits for nickel (Ni) at least as protective as the provisions specified in paragraphs (a) and (b) of this section.

(a) The emission limit for Ni contained in the gases discharged to the atmosphere from a designated facility is 210 pounds of Ni per trillion Btu (lb/TBtu) in an input-based format and 0.002 pounds of Ni per megawatt hour (lb/MWh) in an output-based format. The SI equivalent is 0.25 ng/J.

(b) The emission limit for Ni for oil-fired electric utility steam generating units does not apply if the owner/operator permanently uses distillate oil as fuel. Except as provided in paragraph (5) of this section, the emissions limit for Ni for oil-fired electric utility steam generating units will immediately apply if the owner/operator subsequently uses a fuel other than distillate oil.

(c) If you use an electrostatic precipitator (ESP) to meet a Ni emissions limit in this part, you must operate the ESP such that the hourly average voltage and secondary current (or total power input) do not fall below the limit established in the initial or subsequent performance test.

(d) If you use a control device or combination of control devices other than an ESP to meet the Ni emissions limit, or you wish to establish and monitor an alternative operating limit and alternative monitoring parameters for an ESP, you must apply to the Administrator for approval of alternative monitoring under § 60.13(i).

(e) If you comply with the requirements in § 60.4015(b) for switching fuel, and you must switch fuel because of an emergency, you must notify the Administrator in writing within 30 days of using a fuel other than distillate oil.

§ 60.4020 Compliance Provisions and Performance Testing

For approval, a State plan shall include the performance testing compliance demonstration requirements as listed in paragraphs (a) and (b) of this section.

(a) Affected facilities will conduct a performance test to demonstrate compliance with this section no later than 180 days after the initial startup or 180 days after publication of the final amendments, whichever is later and annually thereafter. The performance test is to be conducted using Method 29 of appendix A of this part to determine Ni emission concentration in the flue gas stream. The Ni emissions concentration for compliance under this part is determined by the three-run average (nominal 1-hour runs) using Method 29 of appendix A of this part for the initial and subsequent performance tests.

(b) The owner or operator shall demonstrate compliance with the Ni limit in § 60.46a according to the procedures in this paragraph to convert the Method 29 Ni measurement from the performance test to the selected format for comparison to the applicable § 60.46a Ni emission limits.

(1) Sum the Ni concentrations obtained from the Method 29 test runs, milligrams per dscm (mg/dscm).

(2) Calculate the total volumetric flow obtained during the Method 29 test runs, (dscm).

(3) Multiply the total Ni concentration times the total volumetric flow for the duration of the initial compliance testing period to obtain the total mass of Ni in milligrams.

(4) Calculate the input-based Ni emissions rate in a lb/TBtu format using Equation 1 of this section.

$$ER = \frac{M \times \text{conversion factor}}{TP_{\text{input-based}}} \qquad \text{(Eq. 1)}$$

Where:

ER = Ni emissions rate, (lb/TBtu);
M = Total mass of Ni emissions, (mg);
Conversion factor = 2.205×10^{-6}; used to convert milligrams to pounds; and
$TP_{\text{input-based}}$ = Total power, (TBtu).

(5) Calculate the output-based Ni emissions rate in a lb/MWh format using Equation 2 of this section.

$$ER = \frac{M \times \text{conversion factor}}{TP_{\text{output-based}}} \qquad \text{(Eq. 2)}$$

Where:

ER = Ni emissions rate, (lb/MWh);
M = Total mass of Ni emissions, (mg);
Conversion factor = 2.205×10^{-6}; and
$TP_{\text{output-based}}$ = Total power, (MWh).

§ 60.4025 Reporting and Recordkeeping Guidelines

For approval, a State plan shall include the reporting and recordkeeping provisions listed in § 60.52a of subpart Da of this part, as applicable.

§ 60.4030 Compliance Times

(a) Except as provided for under paragraph (b) of this section, planning, awarding of contracts, and installation of electric utility steam generating unit air emission control equipment capable of meeting the emission guidelines established under § 60.4015 shall be accomplished within 30 months after the effective date of a State emission standard for electric utility steam generating units.

APPENDIX B PART 60

10. Appendix B to part 60 is amended by adding in numerical order new Performance Specification 12A to read as follows:

Performance Specification 12a—Specifications and Test Procedures for Total Vapor Phase Mercury Continuous Emission Monitoring Systems in Stationary Sources

1.0 Scope and Application

1.1 Analyte.

Analyte	CAS No.
Mercury (Hg)	7439–97–6

1.2 Applicability.

1.2.1 This specification is for evaluating the acceptability of total vapor phase Hg continuous emission monitoring systems (CEMS) installed on the exit gases from fossil fuel fired boilers at the time of or soon after installation and whenever specified in the regulations. The Hg CEMS must be capable of measuring the total concentration in µg/m^3 (regardless of speciation) of vapor phase Hg, and recording that concentration on a dry basis, corrected to 20 degrees C and 7 percent CO_2. Particle bound Hg is not included. The CEMS must include a) a diluent (CO_2) monitor, which must meet Performance Specification 3 in 40 CFR part 60, appendix B, and b) an automatic sampling system. Existing diluent and flow monitoring equipment can be used.

This specification is not designed to evaluate an installed CEMS's performance over an extended period of time nor does it identify specific calibration techniques and auxiliary procedures to assess the CEMS's performance. The source owner or operator, however, is responsible to calibrate, maintain, and operate the CEMS properly. The Administrator may require, under CAA section 114, the operator to conduct CEMS performance evaluations at other times besides the initial test to evaluate the CEMS performance. See 40 CFR 60.13(c).

2.0 Summary of Performance Specification

Procedures for measuring CEMS relative accuracy, measurement error and drift are outlined. CEMS installation and measurement location specifications, and data reduction procedures are included. Conformance of the CEMS with the Performance Specification is determined.

3.0 Definitions

3.1 *Continuous Emission Monitoring System (CEMS)* means the total equipment required for the determination of a pollutant concentration. The system consists of the following major subsystems:

3.2 *Sample Interface* means that portion of the CEMS used for one or more of the following: sample acquisition, sample transport, sample conditioning, and protection of the monitor from the effects of the stack effluent.

3.3 *Hg Analyzer* means that portion of the CEMS that measures the total vapor phase Hg mass concentration and generates a proportional output.

3.4 *Diluent Analyzer* (if applicable) means that portion of the CEMS that senses the diluent gas (CO_2) and generates an output proportional to the gas concentration.

3.5 *Data Recorder* means that portion of the CEMS that provides a permanent electronic record of the analyzer output. The data recorder can provide automatic data reduction and CEMS control capabilities.

3.6 *Span Value* means the upper limit of the intended Hg concentration measurement range. The span value is a value equal to two times the emission standard.

3.7 *Measurement Error (ME)* means the difference between the concentration indicated by the CEMS and the known concentration generated by a reference gas when the entire CEMS, including the sampling interface, is challenged. An ME test procedure is performed to document the accuracy and linearity of the CEMS at several points over the measurement range.

3.8 *Upscale Drift (UD)* means the difference in the CEMS output responses to a Hg reference gas when the entire CEMS, including the sampling interface, is challenged after a stated period of operation during which no unscheduled maintenance, repair, or adjustment took place.

3.9 *Zero Drift (ZD)* means the difference in the CEMS output responses to a zero gas when the entire CEMS, including the sampling interface, is challenged after a stated period of operation during which no unscheduled maintenance, repair, or adjustment took place.

3.10 *Relative Accuracy (RA)* means the absolute mean difference between the pollutant concentration(s) determined by the CEMS and the value determined by the reference method (RM) plus the 2.5 percent error confidence coefficient of a series of tests divided by the mean of the RM tests or the applicable emission limit.

4.0 Interferences [Reserved]

5.0 Safety

The procedures required under this performance specification may involve hazardous materials, operations, and equipment. This performance specification may not address all of the safety problems associated with these procedures. It is the responsibility of the user to establish appropriate safety and health practices and determine the applicable regulatory limitations prior to performing these procedures. The CEMS user's manual and materials recommended by the reference method should be consulted for specific precautions to be taken.

6.0 Equipment and Supplies

6.1 CEMS Equipment Specifications.

6.1.1 Data Recorder Scale. The CEMS data recorder output range must include zero and a high level value. The high level value must be approximately 2 times the Hg concentration corresponding to the emission standard level for the stack gas under the circumstances existing as the stack gas is sampled. If a lower high level value is used, the CEMS must have the capability of providing multiple high level values (one of which is equal to the span value) or be capable of automatically changing the high level value as required (up to specified high level value) such that the measured value does not exceed 95 percent of the high level value.

6.1.2 The CEMS design should also provide for the determination of response drift at both the zero and mid-level value. If this is not possible or practical, the design must allow these determinations to be conducted at a low-level value (zero to 20 percent of the high-level value) and at a value between 50 and 100 percent of the high-level value.

6.2 Reference Gas Delivery System. The reference gas delivery system must be designed so that the flowrate of reference gas introduced to the CEMS is the same at all three challenge levels specified in Section 7.1 and at all times exceeds the flow requirements of the CEMS.

6.3 Other equipment and supplies, as needed by the applicable reference method used. See Section 8.6.2.

7.0 Reagents and Standards

7.1 Reference Gases.

7.1.1 Zero—N_2 or Air. Less than 0.1 μg Hg/m³.

7.1.2 Mid-level Hg^0 and $HgCl_2$. 40 to 60 percent of span.

7.1.3 High-level Hg^0 and $HgCl_2$. 80 to 100 percent of span.

7.2 Reagents and Standards. May be required for the reference methods. See Section 8.6.2.

8.0 Performance Specification Test Procedure

8.1 Installation and Measurement Location Specifications.

8.1.1 CEMS Installation. Install the CEMS at an accessible location downstream of all pollution control equipment. Since the Hg CEMS sample system normally extracts gas from a single point in the stack, use a location that has been shown to be free of stratification for SO_2 and NO_X through concentration measurement traverses for those gases. If the cause of failure to meet the RA test requirement is determined to be the measurement location and a satisfactory correction technique cannot be established, the Administrator may require the CEMS to be relocated.

Measurement locations and points or paths that are most likely to provide data that will meet the RA requirements are listed below.

8.1.2 Measurement Location. The measurement location should be (1) at least eight equivalent diameters downstream of the nearest control device, point of pollutant generation, bend, or other point at which a change of pollutant concentration or flow disturbance may occur, and (2) at least two equivalent diameters upstream from the effluent exhaust. The equivalent duct diameter is calculated as per 40 CFR part 60, appendix A, Method 1.

8.1.3 Hg CEMS Sample extraction Point. Use a sample extraction point (1) no less than 1.0 meter from the stack or duct wall, or (2) within the centroidal velocity traverse area of the stack or duct cross section.

8.2 Reference Method (RM) Measurement Location and Traverse Points. The RM measurement location should be at a point or points in the same stack cross sectional area as the CEMS is located, according to the criteria above. The RM and CEMS locations need not be immediately adjacent. They should be as close as possible without causing interference with one another.

8.3 Measurement Error (ME) Test Procedure. The Hg CEMS must be constructed to permit the introduction of known (NIST traceable) concentrations of elemental mercury (Hg^0) and mercuric chloride ($HgCl_2$) separately into the sampling system of the CEMS immediately preceding the sample extraction filtration system such that the entire CEMS can be challenged. Inject sequentially each of the three reference gases (zero, mid-level, and high level) for each Hg species. CEMS measurements of each reference gas shall not differ from their respective reference values by more than 5 percent of the span value. If this specification is not met, identify and correct the problem before proceeding.

8.4 Upscale Drift (UD) Test Procedure.

8.4.1 UD Test Period. While the affected facility is operating at more than 50 percent of normal load, or as specified in an applicable subpart, determine the magnitude of the UD once each day (at 24-hour intervals) for 7 consecutive days according to the procedure given in Sections 8.4.2 through 8.4.3.

8.4.2 The purpose of the UD measurement is to verify the ability of the CEMS to conform to the established CEMS response used for determining emission concentrations or emission rates. Therefore, if periodic automatic or manual adjustments are made to the CEMS zero and response settings, conduct the UD test immediately before these adjustments, or conduct it in such a way that the UD can be determined.

8.4.3 Conduct the UD test at the mid-level point specified in Section 7.1. Evaluate upscale drift for elemental Hg (Hg^0) only. Introduce the reference gas to the CEMS. Record the CEMS response and subtract the reference value from the CEM value (see example data sheet in Figure 12A–1).

8.5 Zero Drift (ZD) Test Procedure.

8.5.1 ZD Test Period. While the affected facility is operating at more than 50 percent of normal load, or as specified in an applicable subpart, determine the magnitude of the ZD once each day (at 24-hour intervals) for 7 consecutive days according to the procedure given in Sections 8.5.2 through 8.5.3.

8.5.2 The purpose of the ZD measurement is to verify the ability of the CEMS to conform to the established CEMS response used for determining emission concentrations or emission rates. Therefore, if periodic automatic or manual adjustments are made to the CEMS zero and response settings, conduct the ZD test immediately before these adjustments, or conduct it in such a way that the ZD can be determined.

8.5.3 Conduct the ZD test at the zero level specified in Section 7.1. Introduce the zero gas to the CEMS. Record the CEMS response and subtract the zero value from the CEM value (see example data sheet in Figure 12A–1).

8.6 Relative Accuracy (RA) Test Procedure.

8.6.1 RA Test Period. Conduct the RA test according to the procedure given in Sections 8.6.2 through 8.6.6 while the affected facility is operating at normal full load, or as specified in an applicable subpart. The RA test can be conducted during the UD test period.

8.6.2 Reference Method (RM). Unless otherwise specified in an applicable subpart of the regulations, use either Method 29 in appendix A to 40 CFR part 60, or ASTM Method D 6784–02 (incorporated by reference in § 60.17) as the RM for Hg. Do not include the filterable portion of the sample when making comparisons to the CEMS results. Conduct all RM tests with paired or duplicate sampling systems.

8.6.3 Sampling Strategy for RM Tests. Conduct the RM tests in such a way that they will yield results representative of the emissions from the source and can be compared to the CEMS data. It is preferable to conduct the diluent (if applicable), moisture (if needed), and Hg measurements simultaneously. However, diluent and moisture measurements that are taken within an hour of the Hg measurements can used to adjust the results to a consistent basis. In order to correlate the CEMS and RM data properly, note the beginning and end of each RM test period for each paired RM run (including the exact time of day) on the CEMS chart recordings or other permanent record of output.

8.6.4 Number and length of RM Tests. Conduct a minimum of nine paired sets of all necessary RM test runs that meet the relative standard deviation criteria of this PS. Use a minimum sample run time of 2 hours for each pair.

Note: More than nine paired sets of RM tests can be performed. If this option is chosen, test results can be rejected so long as the total number of paired RM test results used to determine the CEMS RA is greater than or equal to nine. However, all data must be reported, including the rejected data.

8.6.5 Correlation of RM and CEMS Data. Correlate the CEMS and the RM test data as to the time and duration by first determining from the CEMS final output (the one used for reporting) the integrated average pollutant concentration or emission rate for each pollutant RM test period. Consider system response time, if important, and confirm that the results are on a consistent moisture, temperature, and diluent concentration basis with the paired RM test. Then, compare each integrated CEMS value against the corresponding average of the paired RM values.

8.6.6 Paired RM Outliers.

8.6.6.1 Outliers are identified through the determination of precision and any systematic bias of the paired RM tests. Data that do not meet this criteria should be flagged as a data quality problem. The primary reason for performing dual RM sampling is to generate information to quantify the precision of the RM data. The relative standard deviation (RSD) of paired data is the parameter used to quantify data precision. Determine RSD for two simultaneously gathered data points as follows:

$$RSD = 100\% * \left|(Ca - Cb)\right| / (Ca + Cb) \qquad \text{Eq. 12A-1}$$

where Ca and Cb are concentration values determined from trains A and B respectively. For RSD calculation, the concentration units are unimportant so long as they are consistent.

8.6.6.2 A minimum precision criteria for RM Hg data is that RSD for any data pair must be ≤10 percent as long as the mean Hg concentration is greater than 1.0 $\mu g/m^3$. If the mean Hg concentration is less than or equal to 1.0 $\mu g/m^3$, the RSD must be ≤20 percent. Pairs of RM data exceeding these RSD criteria should be eliminated from the data set used to develop a Hg CEMS correlation or to assess CEMS RA.

8.6.7 Calculate the mean difference between the RM and CEMS values in the units of the emission standard, the standard deviation, the confidence coefficient, and the RA according to the procedures in Section 12.0.

8.7 Reporting. At a minimum (check with the appropriate EPA Regional Office, State, or local Agency for additional requirements, if any), summarize in tabular form the results of the RD tests and the RA tests or alternative RA procedure, as appropriate. Include all data sheets, calculations, charts (records of CEMS responses), reference gas concentration certifications, and any other information necessary to confirm that the performance of the CEMS meets the performance criteria.

9.0 Quality Control [Reserved]

10.0 Calibration and Standardization [Reserved]

11.0 Analytical Procedure

Sample collection and analysis are concurrent for this Performance Specification (see Section 8.0). Refer to the RM employed for specific analytical procedures.

12.0 Calculations and Data Analysis

Summarize the results on a data sheet similar to that shown in Figure 2-2 for Performance Specification 2.

12.1 Consistent Basis. All data from the RM and CEMS must be on a consistent dry basis and, as applicable, on a consistent diluent basis. Correct the RM and CEMS data for moisture and diluent as follows:

12.1.1 Moisture Correction (as applicable). Correct each wet RM run for moisture with the corresponding Method 4 data; correct each wet CEMS run using the corresponding CEMS moisture monitor date using Equation 12A–2.

$$\text{Concentration}_{(dry)} = \frac{\text{Concentration}_{(wet)}}{(1 - B_{ws})} \qquad \text{Eq. 12A-2}$$

12.1.2 Correction to Units of Standard (as applicable). Correct each dry RM run to the units of the emission standard with the corresponding Method 3B data; correct each dry CEMS run using the corresponding CEMS diluent monitor data as follows:

12.1.3 Correct to Diluent Basis. The following is an example of concentration (ppm) correction to 7 percent oxygen.

$$ppm_{(corr)} = ppm_{(uncorr)}\left[\frac{20.9 - 7.0}{20.9 - \%O_{2\,(dry)}}\right] \qquad \text{Eq. 12A-3}$$

The following is an example of mass/gross calorific value (lbs/million Btu) correction. lbs/MMBtu = $Conc_{(dry)}$ (F-factor) ((20.9/ (20.9—percent O_2))

12.2 Arithmetic Mean. Calculate the arithmetic mean of the difference, d, of a data set as follows:

$$\bar{d} = \frac{1}{n}\sum_{i=1}^{n} d_i \qquad \text{Eq. 12A-4}$$

Where:

n = Number of data points.

12.3 Standard Deviation. Calculate the standard deviation, S_d, as follows:

$$S_d = \left[\frac{\sum_{i=1}^{n} d_i^2 - \frac{\left[\sum_{i=1}^{n} d_i\right]^2}{n}}{n-1}\right]^{\frac{1}{2}} \qquad \text{Eq. 12A-5}$$

Where:

$\sum_{i=1}^{n} d_i$ = Algebraic summation of the individual differences d_i.

12.4 Confidence Coefficient. Calculate the 2.5 percent error confidence coefficient (one-tailed), CC, as follows:

$$CC = t_{0.975}\frac{S_d}{\sqrt{n}} \qquad \text{Eq. 12A-6}$$

12.5 Relative Accuracy. Calculate the RA of a set of data as follows:

$$RA = \frac{\left[|\bar{d}| + |CC|\right]}{\overline{RM}} \times 100 \qquad \text{Eq. 12A-7}$$

Where:

$|\bar{d}|$ = Absolute value of the mean differences (from Equation 12A–4).

$|CC|$ = Absolute value of the confidence coefficient (from Equation 12A–6).

$\overline{RM}$ = Average RM value. In cases where the average emissions for the test are less than 50 percent of the applicable standard, substitute the emission standard value in the denominator of Eq. 12A–7 in place of $R|\overline{M}|$. In all other cases, use R|M|

13.0 Method Performance

13.1 Measurement Error (ME). ME is assessed at mid-level and high-level values as given below using standards for both Hg^0 and $HgCl_2$. The mean difference between the indicated CEMS concentration and the reference concentration value for each standard shall be no greater than 5 percent of span. The same difference for the zero reference gas shall be no greater than 5 percent of span.

13.2 Upscale Drift (UD). The CEMS design must allow the determination of UD of the analyzer. The CEMS response can not drift or deviate from the benchmark value of the reference standard by more than 5 percent of span for the mid level value. Evaluate upscale drift for Hg^0 only.

13.3 Zero Drift (ZD). The CEMS design must allow the determination of drift at the zero level. This drift shall not exceed 5 percent of span.

13.4 Relative Accuracy (RA). The RA of the CEMS must be no greater than 20 percent of the mean value of the RM test data in terms of units of the emission standard, or 10 percent of the applicable standard, whichever is greater.

14.0 Pollution Prevention. [Reserved]

15.0 Waste Management. [Reserved]

16.0 Alternative Procedures. [Reserved]

17.0 Bibliography.

17.1 40 CFR part 60, appendix B, "Performance Specification 2—Specifications and Test Procedures for SO_2 and NO_X Continuous Emission Monitoring Systems in Stationary Sources."

17.2 40 CFR part 60, appendix A, "Method 29—Determination of Metals Emissions from Stationary Sources."

17.3 ASTM Method D6784–02, "Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method)."

18.0 *Tables and Figures.*

TABLE 12A–1.—T-VALUES.

n [a]	$t_{0.975}$	n [a]	$t_{0.975}$	n [a]	$t_{0.975}$
2	12.706	7	2.447	12	2.201
3	4.303	8	2.365	13	2.179
4	3.182	9	2.306	14	2.160
5	2.776	10	2.262	15	2.145
6	2.571	11	2.228	16	2.131

[a] The values in this table are already corrected for n-1 degrees of freedom. Use n equal to the number of individual values.

	Day	Date and time	Reference value (C)	CEMS value (M)	Measurement error	Drift
Zero Level						
Mid-level						

	Day	Date and time	Reference value (C)	CEMS value (M)	Measurement error	Drift
High-level						

Figure 12A–1.—Zero and Upscale Drift Determination

PART 63—[AMENDED]

11. The authority citation for part 63 continues to read as follows:

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

12. Section 63.14 is amended by adding paragraph (b)(35) to read as follows:

§ 63.14 Incorporations by Reference.

* * * * *

(b) * * *

(35) ASTM D6784–02, Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), for appendix B to part 63, Method 324.

* * * * *

APPENDIX B PART 63

13. Appendix B to part 63 is amended by adding in numerical order new Method 324 to read as follows:

Method 324—Determination of Vapor Phase Flue Gas Mercury Emissions From Stationary Sources Using Dry Sorbent Trap Sampling

1.0 Introduction.

This method describes sampling criteria and procedures for the continuous sampling of mercury (Hg) emissions in combustion flue gas streams using sorbent traps. Analysis of each trap can be by cold vapor atomic fluorescence spectrometry (AF) which is described in this method, or by cold vapor atomic absorption spectrometry (AA). Only the AF analytical method is detailed in this method, with reference being made to other published methods for the AA analytical procedure. The Electric Power Research Institute has investigated the AF analytical procedure in the field with the support of ADA–ES and Frontier Geosciences, Inc. The AF procedure is based on EPA Method 1631, Revision E: Mercury in Water by Oxidation, Purge and Trap, and Cold Vapor Atomic Fluorescence Spectrometry. Persons using this method should have a thorough working knowledge of Methods 1, 2, 3, 4 and 5 of 40 CFR part 60, appendix A.

1.1 Scope and Application.

1.1.1 Analytes. The analyte measured by this method is total vapor-phase Hg, which represents the sum of elemental (CAS Number 7439–97–6) and oxidized forms of Hg, mass concentration (micrograms/dscm) in flue gas samples.

1.1.2 Applicability. This method is applicable to the determination of vapor-phase Hg concentrations ranging from 0.03 μg/dncm to 100 μg/dncm in low-dust applications, including controlled and uncontrolled emissions from stationary sources, only when specified within the regulations. When employed to demonstrate compliance with an emission regulation, paired sampling is to be performed as part of the method quality control procedure. The method is appropriate for flue gas Hg measurements from combustion sources. Very low Hg concentrations will require greater sample volumes. The method can be used over any period from 30 minutes to several days in duration, provided appropriate sample volumes are collected and all the quality control criteria in Section 9.0 are met. When sampling for periods greater than 12 hours, the sample rate is required to be maintained at a constant proportion to the total stack flowrate, ±25 percent to ensure representativeness of the sample collected.

2.0 Summary of Method.

Known volumes of flue gas are extracted from a duct through a single or paired sorbent trap with a nominal flow rate of 0.2 to 0.6 liters per minute through each trap. Each trap is then acid leached and the resulting leachate is analyzed by cold vapor atomic fluorescence spectrometry (CVAFS) detection. The AF analytical procedure is described in detail in EPA Method 1631. Analysis by AA can be performed by existing recognized procedures, such as that contained in ASTM Method D6784–02 (incorporated by reference, see § 63.14) or EPA Method 29.

3.0 Definitions. [Reserved]

4.0 Clean Handling and Contamination.

During preparation of the sorbent traps, as well as transport, field handling, sampling, recovery, and laboratory analysis, special attention must be paid to cleanliness procedures. This is to avoid Hg contamination of the samples, which generally contain very small amounts of Hg. For specifics on how to avoid contamination, Section 4 of Method 1631 should be well understood.

5.0 Safety.

5.1 Site hazards must be prepared for in advance of applying this method in the field. Suitable clothing to protect against site hazards is required, and requires advance coordination with the site to understand the conditions and applicable safety policies. At a minimum, portions of the sampling system will be hot, requiring appropriate gloves, long sleeves, and caution in handling this equipment.

5.2 Laboratory safety policies are to minimize risk of chemical exposure and to properly handle waste disposal. Personnel will don appropriate laboratory attire according to a Chemical Hygiene Plan established by the laboratory. This includes, but is not limited to, laboratory coat, safety goggles, and nitrile gloves under clean gloves.

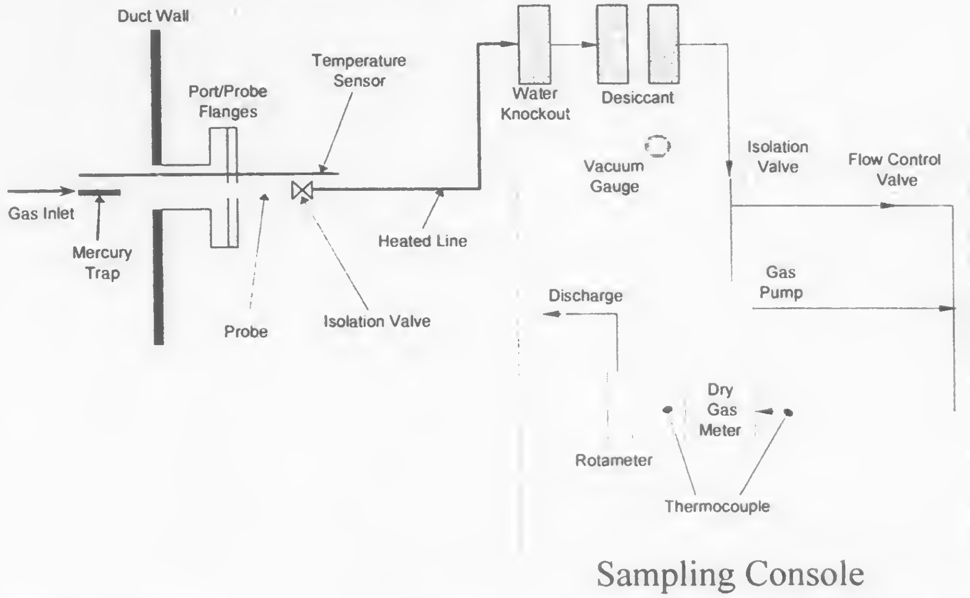
5.3 The toxicity or carcinogenicity of reagents used in this method has not been fully established. The procedures required in this method may involve hazardous materials, operations, and equipment. This method may not address all of the safety problems associated with these procedures. It is the responsibility of the user to establish appropriate safety and health practices and determine the applicable regulatory limitations prior to performing these procedures. Each chemical should be regarded as a potential health hazard and exposure to these compounds should be minimized. Chemists should refer to the MSDS for each chemical with which they are working.

5.4 Any wastes generated by this procedure must be disposed of according to a hazardous materials management plan that details and tracks various waste streams and disposal procedures.

6.0 Equipment and Supplies.

6.1 Hg Sampling Train. A Schematic of a single trap sampling train used for this method is shown in Figure 324–1. Where this method is used to collect data to demonstrate compliance with a regulation, it must be performed with paired sorbent trap equipment.

Figure 324–1. Hg Sampling Train Illustrating Single Trap.



6.1.1 Sorbent Trap. Use sorbent traps with separate main and backup sections in series for collection of Hg. Selection of the sorbent trap shall be based on: (1) Achievement of the performance criteria of this method, and (2) data is available to demonstrate the method can pass the criteria in EPA Method 301 when used in this method and when the results are compared with those from EPA Method 29, EPA Method 101A, or ASTM Method 6784–02 for the measurement of vapor-phase Hg in a similar flue gas matrix. Appropriate traps are referred to as "sorbent trap" throughout this method. The method requires the analysis of Hg in both main and backup portions of the sorbent within each trap. The sorbent trap should be obtained from a reliable source that has clean handling procedures in place for ultra low-level Hg analysis. This will help assure the low Hg environment required to manufacture sorbent traps with low blank levels of Hg. Sorbent trap sampling requirements or needed characteristics are shown in Table 324–1. Blank/cleanliness and other requirements are described in Table 324–2. The sorbent trap is supported on a probe and inserted directly into the flue gas stream, as shown on Figure 324–1. The sampled sorbent trap is the entire Hg sample.

6.1.2 Sampling Probe. The probe assembly shall have a leak-free attachment to the sorbent trap. For duct temperatures from 200 to 375°F, no heating is required. For duct temperatures less than 200°F, the sorbent tube must be heated to at least 200°F or higher to avoid liquid condensation in the sorbent trap by using a heated probe. For duct temperatures greater than 375°F, a large sorbent trap must be used, as shown in Table 324–1, and no heating is required. A thermocouple is used to monitor stack temperature.

6.1.3 Umbilical Vacuum Line. A 250 °F heated umbilical line shall be used to convey to the moisture knockout the sampled gas that has passed through the sorbent trap and probe assembly.

6.1.4 Moisture Knockout. Impingers and desiccant can be combined to dry the sample gas prior to entering the dry gas meter. Alternative sample drying methods are acceptable as long as they do not affect sample volume measurement.

6.1.5 Vacuum Pump. A leak tight vacuum pump capable of delivering a controlled extraction flow rate between 0.1 to 0.8 liters per minute.

6.1.6 Dry Gas Meter. Use a dry gas meter that is calibrated according to the procedures in 40 CFR part 60, appendix A, Method 5, to measure the total sample volume collected. The dry gas meter must be sufficiently accurate to measure the sample volume within 2 percent, calibrated at the selected flow rate and conditions actually encountered during sampling, and equipped with a temperature sensor capable of measuring typical meter temperatures accurately to within 3 °C (5.4 °F).

6.2 Sample Analysis Equipment. Laboratory equipment as described in Method 1631, Sections 6.3 to 6.7 is required for analysis by AF. For analysis by AA, refer to Method 29 or ASTM Method 6784–02.

TABLE 324–1.—SORBENT TRAP AND SAMPLING REQUIREMENTS

Item to be determined	Small sorbent trap	Large sorbent trap
Sampling Target: Hg Loading Range, ug	Minimum = 0.025 µg/trap.	Minimum = 0.10 µg/trap.
	Maximum = 150 µg/trap	Maximum = 1800 µg/trap.
Sampling Duration Required: limits on sample times.	Minimum = 30 minutes	Minimum = 24 hours.
	Maximum = 24 hours	Maximum = 10 days.
Sampling Temperature Required	200 to 375 °F	200 to 425 °F.
Sampling Rate Required	0.2 to 0.6 L/min; start at 0.4 L/min	0.2 to 0.6 L/min; start at 0.4 L/min.
	Must be constant proportion within ±25% if greater than 12 hours; constant rate within ±25% if less than 12 hours.	Must be constant proportion of stack flowrate within ±25%.

7.0 Analysis by AF, Reagents and Standards.

For analysis by AF, use Method 1631, Sections 7.1–7.3 and 7.5–7.12 for laboratory reagents and standards. Refer to Method 29 or ASTM Method 6784–02 for analysis by AA.

7.1 Reagent Water. Same as Method 1631, Section 7.1.

7.2 Air. Same as Method 1631, Section 7.2.

7.3 Hydrochloric Acid. Same as Method 1631, Section 7.3.

7.4 Stannous Chloride. Same as Method 1631, Section 7.5.

7.5 Bromine Monochloride (BrCl, 0.01N). Same as Method 1631, Section 7.6.

7.6 Hg Standards. Same as Method 1631, Sections 7.7 to 7.11.

7.7 Nitric Acid. Reagent grade, low Hg.

7.8 Sulfuric Acid. Reagent grade, low Hg.

7.9 Nitrogen. Same as Method 1631, Section 7.12.

7.10 Argon. Same as Method 1631, Section 7.13.

8.0 Sample Collection and Transport.

8.1 Pre-Test.

8.1.1 Site information should be obtained in accordance with Method 1 (40 CFR part 60, appendix A). Identify a location that has been shown to be free of stratification for SO_2 and NO_X through concentration measurement traverses for those gases. An estimation of the expected Hg concentration is required to establish minimum sample volumes. Based on estimated minimum sample volume and normal sample rates for each size trap used, determine sampling duration with the data provided in Table 324–1.

8.1.2 Sorbent traps must be obtained from a reliable source such that high quality control and trace cleanliness are maintained. Method detection limits will be adversely affected if adequate cleanliness is not maintained. Sorbent traps should be handled only with powder-free low Hg gloves (vinyl, latex, or nitrile are acceptable) that have not touched any other surface. The sorbent traps should not be removed from their clean storage containers until after the preliminary leak check has been completed. Field efforts at clean handling of the sorbent traps are key to the success of this method.

8.1.3 Assemble the sample train according to Figure 324–1, except omit the sorbent trap.

8.1.4 Preliminary Leak Check. Perform system leak check without the single or dual sorbent traps in place. This entails plugging the end of the probe to which each sorbent trap will be affixed, and using the vacuum pump to draw a vacuum in each sample train. Adjust the vacuum in the sample train to 15 inches Hg. A rotameter on the dry gas meter will indicate the leakage rate. The leakage rate must be less than 2 percent of the planned sampling rate.

8.1.5 Release the vacuum in the sample train, turn off the pump, and affix the sorbent trap to the end of the probe, using clean handling procedures. Leave the flue gas end of the sorbent trap plugged.

8.1.6 Pre-test leak check. Perform a leak check with the Sorbent trap in place. Use the sampling vacuum pump to draw a vacuum in the sample train. Adjust the vacuum in the sample train to 15 inches Hg. A rotameter on the dry gas meter will indicate the leakage rate. Record the leakage rate. The leakage rate must be less than 2 percent of the planned sampling rate. Once the leak check passes this criterion, carefully release the vacuum in the sample train (the sorbent trap must not be exposed to abrupt changes in pressure or to backflow), then re-cap the flue gas end of the sorbent trap until the probe is ready for insertion. The sorbent trap packing beds must be undisturbed by the leak test to prevent gas channeling through the media during sampling.

8.1.7 Use temperature controllers to heat the portions of the trains that require it. The sorbent trap must be maintained between 200 and 375 °F during sampling.

8.1.8 Gas temperature and static pressure must be considered prior to sampling in order to maintain proper safety precautions during sampling.

8.2 Sample Collection.

8.2.1 Remove the plug from the end of a sorbent trap and store it in a clean sorbent trap storage container. Remove the sample duct port cap and insert the probe. Secure the probe and ensure that no leakage occurs between the duct and environment.

8.2.2 Record initial data including the start time, starting dry gas meter readings, and the name of the field tester(s). Set the initial sample flow rate to 0.4 L/min (+/− 25 percent).

8.2.3 For constant-flow sampling (samples less than 12 hours in duration), every 10–15 minutes during the sampling period: record the time, the sample flow rate, the gas meter readings, the duct temperature, the flow meter temperatures, temperatures of heated equipment such as the vacuum lines and the probes (if heated), and the sampling vacuum reading. Adjust the sample rate as needed, maintaining constant sampling within +/− 25 percent of the initial reading.

8.2.4 For constant proportion sampling (samples 12 hours or greater in duration), every hour during the sampling period: record the time, the sample flow rate, the gas meter readings, the duct temperature, the flow meter temperatures, temperatures of heated equipment such as the vacuum lines and the probes (if heated), and the sampling vacuum readings. Also record the stack flow rate reading, whether provided as a CEM flow monitor signal, a pitot probe or other direct flow indication, or a plant input signal. Adjust the sampling rate to maintain proportional sampling within +/− 25 percent relative to the total stack flowrate.

8.2.5 Obtain and record operating data for the facility during the test period, including total stack flowrate and the oxygen concentration at the flue gas test location. Barometric pressure must be obtained for correcting sample volume to standard conditions.

8.2.6 Post Test Leak Check. When sampling is completed, turn off the sample pump, remove the probe from the port and carefully re-plug the end of the sorbent trap. Perform leak check by turning on the sampling vacuum pumps with the plug in place. The rotameter on the dry gas meters will indicate the leakage rates. Record the leakage rate and vacuum. The leakage rate must be less than 2 percent of the actual sampling rate. Following the leak check, carefully release the vacuum in the sample train.

8.2.7 Sample Recovery. Recover each sampled sorbent trap by removing it from the probe, plugging both ends with the clean caps provided with the sorbent trap, and then wiping any dirt off the outside of the sorbent trap. Place the sorbent trap into the clean sample storage container in which it was provided, along with the data sheet that includes the post-test leak check, final volume, and test end time.

8.3 Quality Control Samples and Requirements.

8.3.1 Field blanks. Refer to Table 324–2.

8.3.2 Duplicate (paired or side by side) samples. Refer to Section 8.6.6 of Performance Specification 12A of 40 CFR part 60, appendix B for this criteria.

8.3.3 Breakthrough performance data ("B" bed in each trap, or second traps behind). Refer to Table 324–2.

8.3.4 Field spikes (sorbent traps spiked with Hg in the lab and periodically sampled in the field to determine overall accuracy). Refer to Table 324–2.

8.3.5 Laboratory matrix and matrix spike duplicates. Refer to Table 324–2.

9.0 Quality Control.

Table 324–2 summarizes the major quantifiable QC components.

TABLE 324–2.—QUALITY CONTROL FOR SAMPLES

QA/QC specification	Acceptance criteria	Frequency	Corrective action
Leak-check.	<2% of sampling rate.	Pre- and post-sampling.	Pre-sampling: repair leak. Post sampling: Flag data and repeat run if for regulatory compliance.
Sample Flow Rate for samples less than 12 hours in duration.	0.4 L/min initially and ±25% of initial rate throughout run.	Throughout run every 10–15 minutes.	Adjust when data is recorded.
Sample Flow Rate for samples greater than 12 hours in duration.	0.4 L/min initially and maintain ±25% of ration of flue gas flow rate throughout sampling.	Throughout run every hour.	Adjust when data is recorded.

TABLE 324–2.—QUALITY CONTROL FOR SAMPLES—Continued

QA/QC specification	Acceptance criteria	Frequency	Corrective action
Sorbent trap laboratory blank (same lot as samples).	<5 ng/trap and a standard deviation of <1:0 ng/trap (n=3).	3 per analysis set of 20 sorbent traps.	
Sorbet trap field blank (same lot as samples)	<5 ng/trap and a standard deviation of <1.0 ng/trap (n=3) OR <5% of average sample collected.	1 per every 10 field samples collected.	
B-Trap Bed Analysis.	<2% of A-Trap Bed Value OR < 5 ng/trap.	Every sample.	
Paired Train Results.	Same as Section 8.6.6 of PS–12A of 40 CFR Par 60, Appendix B.		
Field Spikes.	80% to 120% recovery.	For long-term regulatory monitoring, 1 per every 3 samples for the first 12 samples.	If the first 4 field spikes do not meet the ±20% criteria, take corrective sampling and laboratory measures and repeat at the 1 per every 3 sample rate until the ±20% criteria is met.
Laboratory matrix and matrix spike duplicates.	85% to 115% recovery.	1 per every 10 or 20 samples—to be determined.	

10.0 Calibration and Standards.

Same as Sections 10.1, 10.2 and 10.4 of Method 1631.

10.1 Calibration and Standardization. Same as Sections 10.1 and 10.4 of Method 1631.

10.2 Bubbler System. Same as Section 10.2 of M1631.

10.3 Flow-Injection System. Not applicable.

11.0 Analytical Procedures.

11.1 Preparation Step. The sorbent traps are received and processed in a low-Hg environment (class-100 laminar-flow hood and gaseous Hg air concentrations below 20 ng/m^3) following clean-handling procedures. Any dirt or particulate present on the exterior of the trap must be removed to avoid contamination of the sample. The sorbent traps are then opened and the sorbent bed(s) transferred to an appropriate sized trace-clean vessel. It is recommended that the height of the trace-clean vessel be at least 3 times the diameter to facilitate a refluxing action.

11.2 Leaching Step. The sorbent trap is then subjected to a hot-acid leach using a 70:30 ratio mixture of concentrated HNO_3/H_2SO_4. The acid volume must be 40 percent of the expected end volume of the digest after dilution. The HNO_3/H_2SO_4 acid to carbon ratio should be approximately 35:1. The leachate is then heated to a temperature of 50 to 60°C for 1.5 to 2.0 hours in the finger-tight capped vessels. This process may generate significant quantities of noxious and corrosive gasses and must only be performed in a well-ventilated fume hood. Care must be taken to prevent excessive heated leaching of the samples as this will begin to break down the charcoal material.

11.3 Dilution Step. After the leached samples have been removed from the hot plate and allowed to cool to room temperature, they are brought to volume with a 5 percent (v/v) solution of 0.01 N BrCl. As the leaching digest contains a substantial amount of dissolved gasses, add the BrCl slowly, especially if the samples are still warm. As before, this procedure must be performed in a properly functioning fume hood. The sample is now ready for analysis.

11.4 Hg Reduction and Purging. (Reference Section 11.2 of M1631 except that NH_2OH is not used.)

11.4.1 Bubbler System. Pipette an aliquot of the digested sample into the bubbler containing pre-blanked reagent water and a soda lime trap connected to the exhaust port. Add stannous chloride ($SnCl_2$) to reduce the aliquot and then seal the bubbler. Connect gold sample traps to the end of the soda lime trap as shown in Figures 1 and 2 of Method 1631. Finally, connect the N_2 lines and purge for 20 minutes. The sample trap can then be added into the analytical train. M1631, Section 11.2.1.

11.4.2 Flow Injection System. If required.

11.5 Desorption of Hg from the gold trap, and peak evaluation. Use Section 11.3 and 11.4 in M1631.

11.6 Instrument Calibration. Analyze the standards by AA or AF following the guidelines specified by the instrument manufacturer. Construct a calibration curve by plotting the absorbances of the standards versus µg/l Hg. The R^2 for the calibration curve should be 0.999 or better. If the curve does not have an R^2 value equal to or better than 0.999 then the curve should be rerun. If the curve still does not meet this criteria then new standards should be prepared and the instrument recalibrated. All calibration points contained in the curve must be within 10 percent of the calibration value when the calibration curve is applied to the calibration standards.

11.7 Sample Analysis. Analyze the samples in duplicate following the same procedures used for instrument calibration. From the calibration curve, determine sample Hg concentrations. To determine total Hg mass in each sample fraction, refer to calculations in Section 15. Record all sample dilutions

11.8 Continued Calibration Performance. To verify continued calibration performance, a continuing calibration check standard should be run every 10 samples. The measured Hg concentration of the continuing calibration check standard must be within 10 percent of the expected value.

11.9 Measurement Precision. The QA/QC for the analytical portion of this method is that every sample, after it has been prepared, is to be analyzed in duplicate with every tenth sample analyzed in triplicate. These results must be within 10 percent of each other. If this is not the case, then the instrument must be recalibrated and the samples reanalyzed.

11.10 Measurement Accuracy. Following calibration, an independently prepared standard (not from same calibration stock solution) should be analyzed. In addition, after every ten samples, a known spike sample (standard addition) must be analyzed. The measured Hg content of the spiked samples must be within 10 percent of the expected value.

11.11 Independent QA/QC Checks. It is suggested that the QA/QC procedures developed for a test program include submitting, on occasion, spiked Hg samples to the analytical laboratory by either the prime contractor, if different from the laboratory, or an independent organization. The measured Hg content of reference samples must be within 15 percent of the expected value. If this limit is exceeded, corrective action (*e.g.*, re-calibration) must be taken and the samples re-analyzed.

11.12 Quality Assurance/Quality Control. For this method, it is important that both the sampling team and analytical people be very well trained in the procedures. This is a complicated method that requires a high-level of sampling and analytical experience. For the sampling portion of the QA/QC procedure, both solution and field blanks are required. It should be noted that if high-quality reagents are used and care is taken in their preparation and in the train assembly, there should be little, if any, Hg measured in either the solution or field blanks.

11.13 Solution Blanks. Solution blanks must be taken and analyzed every time a new batch of solution is prepared. If Hg is detected in these solution blanks, the concentration is subtracted from the measured sample results. The maximum amount that can be subtracted is 10 percent of the measured result or 10 times the detection limit of the instrument whichever is lower. If the solution blanks are greater than 10 percent the data must be flagged as suspect.

11.14 Field Blanks. A field blank is performed by assembling a sample train, transporting it to the sampling location during the sampling period, and recovering it as a regular sample. These data are used to ensure that there is no contamination as a result of the sampling activities. A minimum of one field blank at each sampling location must be completed for each test site. Any Hg detected in the field blanks cannot be subtracted from the results. Whether or not the Hg detected in the field blanks is significant is determined based on the QA/QC procedures established prior to the testing. At a minimum, if field blanks exceed 30 percent of the measured value at the corresponding location, the data must be flagged as suspect.

12.0 Calculations and Data Analysis

Use Section 12 in M1631.

13.0 Constant Proportion Sampling

Calculate the Sample Rate/Stack Flow = "x." "X" must be maintained within 0.75 "x" to 1.25 "x" for sampling times in excess of 12 hours. For mass emission rate calculations, use the flow CEM total measured flow corresponding to the sorbent trap sample time period.

14.0 Sampling and Data Summary Calculations

Refer to 40 CFR part 60, appendix A, Methods 2, 4, and 5 for example calculations.

15.0 Pollution Prevention

Refer to Section 13 in Method 1631.

16.0 Waste Management

Refer to Section 14 in Method 1631.

17.0 Bibliography

17.1 EPA Method 1631, Revision E "Mercury in Water by Oxidation, Purge and Trap, and Cold Vapor Atomic Fluorescence Spectrometry," August 2002.

17.2 "Comparison of Sampling Methods to Determine Total and Speciated Mercury in Flue Gas," CRADA F00–038 Final Report, DOE/NETL–2001/1147, January 4, 2001.

17.3 40 CFR part 60, appendix A, "Method 29—Determination of Metals Emissions From Stationary Sources."

17.4 40 CFR part 60, appendix B, "Performance Specification 12A, Specification and Test Procedures for Total Vapor Phase Mercury Continuous Emission Monitoring Systems in Stationary Sources."

17.5 ASTM Method D6784–02, "Standard Test Method for Elemental, Oxidized, Particle-bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method)."

[FR Doc. 04–1539 Filed 1–29–04; 8:45 am]

BILLING CODE 6560–50–P

Federal Register

Friday,
January 30, 2004

Part V

Department of Health and Human Services

Centers for Medicare & Medicaid Services

42 CFR Part 412

Medicare Program; Prospective Payment System for Long-Term Care Hospitals: Proposed Annual Payment Rate Updates and Policy Changes; Proposed Rule

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Medicare & Medicaid Services

42 CFR Part 412

[CMS–1263–P]

RIN 0938–AM84

Medicare Program; Prospective Payment System for Long-Term Care Hospitals: Proposed Annual Payment Rate Updates and Policy Changes

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

ACTION: Proposed rule.

SUMMARY: This rule proposes an update to the annual payment rates for the Medicare prospective payment system (PPS) for inpatient hospital services provided by long-term care hospitals (LTCHs). The payment amounts and factors used to determine the proposed updated Federal rates that are described in this proposed rule have been determined based on the LTCH PPS rate year. The annual update of the long-term care diagnosis-related groups (LTC–DRG) classifications and relative weights remains linked to the annual adjustments of the acute care hospital inpatient diagnosis-related group system, and will continue to be effective each October 1. The proposed outlier threshold for July 1, 2004, through June 30, 2005, would also be derived from the LTCH PPS rate year calculations. In this proposed rule, we also are proposing to make clarifications to the existing policy regarding the designation of a satellite of a LTCH as an independent LTCH. In addition, we are proposing to expand the existing interrupted stay policy and proposing a change in the procedure for counting days in the average length of stay calculation for Medicare patients for hospitals qualifying as LTCHs.

DATES: We will consider comments if we receive them at the appropriate address, as provided below, no later than 5 p.m. on March 23, 2004.

ADDRESSES: In commenting, please refer to file code CMS–1263–P. Because of staff and resource limitations, we cannot accept comments by facsimile (FAX) transmission.

Submit electronic comments to *http://www.accessdata.fda.gov/scripts/oc/dockets/comments/commentdocket.cfm?AGENCY=CMS* or to *http://www.regulations.gov*. 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–1263–P, P.O. Box 8010, Baltimore, MD 21244–1850.

If you prefer, you may deliver, by hand or courier, your written comments (an original and three copies) to one of the following addresses:

Room 443–G, Hubert H. Humphrey Building, 200 Independence Avenue, SW., Washington, DC 20201, or

Room C5–14–03, Central Building, 7500 Security Boulevard, Baltimore, MD 21244–1850.

(Because access to the interior of the Humphrey 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 commenters who wish to retain proof of filing by stamping in and keeping 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 could be considered late.

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. After the close of the comment period, CMS posts all electronic comments received before the close of the comment period on its public Web site.

For information on viewing public comments, see the beginning of the **SUPPLEMENTARY INFORMATION** section.

FOR FURTHER INFORMATION CONTACT:

Tzvi Hefter, (410) 786–4487 (General information);

Judy Richter, (410) 786–2590 (General information, transition payments, payment adjustments, and onsite discharges and readmissions, interrupted stays, co-located providers, and short-stay outliers);

Michele Hudson, (410) 786–5490 (Calculation of the payment rates, relative weights and case-mix index, market basket update, and payment adjustments);

Ann Fagan, (410) 786–5662 (Patient classification system);

Miechal Lefkowitz, (410) 786–5316 (High-cost outliers and budget neutrality);

Linda McKenna, (410) 786–4537 (Payment adjustments, interrupted stay, and transition period);

Kathryn McCann, (410) 786–7623 (Medigap);

Robert Nakielny, (410) 786–4466 (Medicaid).

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–1263–P and the specific "issue identifier" that precedes the section on which you choose to comment.

Inspection of Public Comments: Comments received timely will be available for public inspection as they are processed, generally beginning approximately 4 weeks after publication of a document, in Room C5–12–08 of the Centers for Medicare & Medicaid Services, 7500 Security Blvd., Baltimore, MD, on Monday through Friday of each week from 8:30 a.m. to 5 p.m. Please call (410) 786–7197 to schedule an appointment to view public comments.

Availability of Copies and Electronic Access

Copies: To order copies of the **Federal Register** containing this document, send your request to: New Orders, Superintendent of Documents, P.O. Box 371954, Pittsburgh, PA 15250–7954. Specify the date of the issue requested and enclose a check or money order payable to the Superintendent of Documents, or enclose your Visa or Master Card number and expiration date. Credit card orders can also be placed by calling the order desk at (202) 512–1800 or by faxing to (202) 512–2250. The cost for each copy is $10. As an alternative, you can view and photocopy the **Federal Register** document at most libraries designated as Federal Depository Libraries and at many other public and academic libraries throughout the country that receive the **Federal Register**.

This **Federal Register** document is also available from the **Federal Register** online database through GPO Access, a service of the U.S. Government Printing Office. The Web site address is: *http://www.access.gpo.gov/nara/index.html*.

To assist readers in referencing sections contained in this preamble, we are providing the following table of contents.

Table of Contents

Acronyms

Because of the many terms to which we refer by acronym in this proposed rule, we are listing the acronyms used and their corresponding terms in alphabetical order below:

BBA Balanced Budget Act of 1997, Pub. L. 105–33
BBRA Medicare, Medicaid, and SCHIP [State Children's Health Insurance Program] Balanced Budget Refinement Act of 1999, Pub. L. 106–113
BIPA Medicare, Medicaid, and SCHIP [State Children's Health Insurance Program] Benefits Improvement and Protection Act of 2000, Pub. L. 106–554
CMS Centers for Medicare & Medicaid Services
COPS Medicare conditions of participation
DRGs Diagnosis-related groups
FY Federal fiscal year
HCRIS Hospital Cost Report Information System
HHA Home health agency
HIPAA Health Insurance Portability and Accountability Act, Pub. L. 104–191
IPPS Acute Care Hospital Inpatient Prospective Payment System
IRF Inpatient rehabilitation facility
LTC–DRG Long-term care diagnosis-related group
LTCH Long-term care hospital
MedPAC Medicare Payment Advisory Commission
MedPAR Medicare provider analysis and review file
OSCAR Online Survey Certification and Reporting (System)
PPS Prospective Payment System
QIO Quality Improvement Organization (formerly Peer Review organization (PRO))
SNF Skilled nursing facility
TEFRA Tax Equity and Fiscal Responsibility Act of 1982, Pub. L. 97–248

I. Background

(If you choose to comment on issues in this section, please include the caption "BACKGROUND" at the beginning of your comments.)

A. Legislative and Regulatory Authority

The Medicare, Medicaid, and SCHIP (State Children's Health Insurance Program) Balanced Budget Refinement Act of 1999 (BBRA) (Pub. L. 106–113) and the Medicare, Medicaid, and SCHIP Benefits Improvement and Protection Act of 2000 (BIPA) (Pub. L. 106–554) provide for payment for both the operating and capital-related costs of hospital inpatient stays in long-term care hospitals (LTCHs) under Medicare Part A based on prospectively set rates. The Medicare prospective payment system (PPS) for LTCHs applies to hospitals described in section 1886(d)(1)(B)(iv) of the Social Security Act (the Act), effective for cost reporting periods beginning on or after October 1, 2002.

Section 1886(d)(1)(B)(iv)(I) of the Act defines a LTCH as "a hospital which has an average inpatient length of stay (as determined by the Secretary) of greater than 25 days." Section 1886(d)(1)(B)(iv)(II) of the Act also provides an alternative definition of LTCHs: specifically, a hospital that first received payment under section 1886(d) of the Act in 1986 and has an average inpatient length of stay (as determined by the Secretary) of greater than 20 days and has 80 percent or more of its annual Medicare inpatient discharges with a principal diagnosis that reflects a finding of neoplastic disease in the 12-month cost reporting period ending in FY 1997.

Section 123 of Pub. L. 106–113 requires the PPS for LTCHs to be a per discharge system with a diagnosis-related group (DRG) based patient classification system that reflects the differences in patient resources and costs in LTCHs while maintaining budget neutrality.

Section 307(b)(1) of Pub. L. 106–554, among other things, mandates that the Secretary shall examine and may provide for adjustments to payments under the LTCH PPS, including adjustments to DRG weights, area wage adjustments, geographic reclassification, outliers, updates, and a disproportionate share adjustment.

In a **Federal Register** document issued on August 30, 2002 (67 FR 55954), we implemented the LTCH PPS authorized under Pub. L. 106–113 and

Pub. L. 106–554. This system uses information from LTCH patient records to classify patients into distinct long-term care diagnosis-related groups (LTC–DRGs) based on clinical characteristics and expected resource needs. Payments are calculated for each LTC–DRG and provisions are made for appropriate payment adjustments. Payment rates under the LTCH PPS are updated annually and published in the **Federal Register**.

The LTCH PPS replaced the reasonable cost-based payment system under the Tax Equity and Fiscal Responsibility Act of 1982 (TEFRA), Pub. L. 97–248, for payments for inpatient services provided by a LTCH with a cost reporting period beginning on or after October 1, 2002. (The regulations implementing the TEFRA (reasonable cost-based) payment provisions are located at 42 CFR part 413.) With the implementation of the prospective payment system for acute care hospitals authorized by the Social Security Amendments of 1983 (Pub. L. 98–21), which added section 1886(d) to the Act, certain hospitals, including LTCHs, were excluded from the PPS for acute care hospitals and were paid their reasonable costs for inpatient services subject to a per discharge limitation or target amount under the TEFRA system. For each cost reporting period, a hospital-specific ceiling on payments was determined by multiplying the hospital's updated target amount by the number of total current year Medicare discharges. The August 30, 2002, final rule further details payment policy under the TEFRA system (67 FR 55954).

In the August 30, 2002, final rule, we presented an in-depth discussion of the LTCH PPS, including the patient classification system, relative weights, payment rates, additional payments, and the budget neutrality requirements mandated by section 123 of Pub. L. 106–113. The same final rule, that established regulations for the LTCH PPS under 42 CFR part 412, subpart O, also contained provisions related to covered inpatient services, limitation on charges to beneficiaries, medical review requirements, furnishing of inpatient hospital services directly or under arrangement, and reporting and recordkeeping requirements.

We refer readers to the August 30, 2002, final (67 FR 55954) rule for a comprehensive discussion of the research and data that supported the establishment of the LTCH PPS.

On June 6, 2003, we published a final rule in the **Federal Register** (68 FR 34122) that set forth the annual update of the payment rates for the Medicare PPS for inpatient hospital services furnished by LTCHs. It also changed the annual period for which the payment rates are effective. The annual updated rates are now effective from July 1 to June 30 instead of from October 1 through September 30. We refer to this time period as a "long-term care hospital rate year" (LTCH PPS rate year). In addition, we changed the publication schedule for these updates to allow for an effective date of July 1. The payment amounts and factors used to determine the annual update of the Federal rates are based on a LTCH PPS rate year. The annual update of the LTC–DRG classifications and relative weights are linked to the annual adjustments of the acute care hospital inpatient diagnosis-related groups and are effective each October 1.

B. Criteria for Classification as a LTCH

1. Classification as a LTCH

Under the existing regulations at §§ 412.23(e)(1) and (2)(i), which implement section 1886(d)(1)(B)(iv)(I) of the Act, to qualify to be paid under the LTCH PPS, a hospital must have a provider agreement with Medicare and must have an average Medicare inpatient length of stay of greater than 25 days. Alternatively, for cost reporting periods beginning on or after August 5, 1997, a hospital that was first excluded from the PPS in 1986, and can demonstrate that at least 80 percent of its annual Medicare inpatient discharges in the 12-month cost reporting period ending in FY 1997 have a principal diagnosis that reflects a finding of neoplastic disease must have an average inpatient length of stay for all patients, including both Medicare and non-Medicare inpatients, of greater than 20 days (§ 412.23(e)(2)(ii)).

Existing § 412.23(e)(3) provides that the average Medicare inpatient length of stay is determined based on all covered and noncovered days of stay of Medicare patients as calculated by dividing the total number of covered and noncovered days of stay of Medicare inpatients (less leave or pass days) by the number of total Medicare discharges for the hospital's most recent complete cost reporting period. Fiscal intermediaries verify that LTCHs meet the average length of stay requirements. We note that the inpatient days of a patient who is admitted to a LTCH without any remaining Medicare days of coverage, regardless of the fact that the patient is a Medicare beneficiary, will not be included in the above calculation. Because Medicare would not be paying for any of the patient's treatment, the patient is not a "Medicare inpatient" and data on the patient's stay would not be included in the Medicare claims processing systems. In order for both covered and noncovered days of a LTCH hospitalization to be included, for purposes of the average length of stay calculation, a patient admitted to the LTCH must have at least one remaining benefit day as described in § 409.61.

The fiscal intermediary's determination of whether or not a hospital qualifies as an LTCH is based on the hospital's discharge data from its most recent cost reporting period and is effective at the start of the hospital's next cost reporting period (§ 412.22(d)). If a hospital does not meet the length of stay requirement, the hospital may provide the intermediary with data indicating a change in the hospital's average length of stay by the same method for the period of at least 5 months of the immediately preceding 6-month period (§ 412.23(e)(3)(ii)). (*See* 68 FR 45464, August 1, 2003.) Requirements for hospitals seeking classification as LTCHs that have undergone a change in ownership, as described in § 489.18, are set forth in § 412.23(e)(3)(iii).

LTCHs that exist as hospitals-within-hospitals or satellite facilities of LTCHs must also meet the criteria set forth in § 412.22(e) or § 412.22(h), respectively, for the LTCH to be excluded from the acute care hospital inpatient prospective payment system (IPPS) and paid under the LTCH PPS.

2. Hospitals Excluded From the LTCH PPS

The following hospitals are paid under special payment provisions, as described in § 412.22(c) and, therefore, are not subject to the LTCH PPS rules:

- Veterans Administration hospitals.
- Hospitals that are reimbursed under State cost control systems approved under 42 CFR part 403.
- Hospitals that are reimbursed in accordance with demonstration projects authorized under section 402(a) of Public Law 90–248 (42 U.S.C. 1395b–1) or section 222(a) of Public Law 92–603 (42 U.S.C. 1395b–1 (note)) (statewide all-payer systems, subject to the rate-of-increase test at section 1814(b) of the Act).
- Nonparticipating hospitals furnishing emergency services to Medicare beneficiaries.

C. Transition Period for Implementation of the LTCH PPS

In the August 30, 2002, final rule, we provided for a 5-year transition period from reasonable cost-based reimbursement to fully Federal prospective payment for LTCHs (67 FR 56038). During the 5-year period, two payment percentages are to be used to determine a LTCH's total payment under the PPS. The blend percentages are as follows:

Cost reporting periods beginning on or after	Prospective payment federal rate percentage	Reasonable cost-based reimbursement rate percentage
October 1, 2002	20	80
October 1, 2003	40	60
October 1, 2004	60	40
October 1, 2005	80	20
October 1, 2006	100	0

D. Limitation on Charges to Beneficiaries

In the August 30, 2002, final rule, we presented an in-depth discussion of beneficiary liability under the LTCH prospective payment system (67 FR 55974–55975). Under § 412.507, as consistent with other established hospital prospective payment systems, a LTCH may not bill a Medicare beneficiary for more than the deductible and coinsurance amounts as specified under §§ 409.82, 409.83, and 409.87 and for items and services as specified under § 489.30(a), if the Medicare payment to the LTCH is the full LTC–DRG payment amount. However, under the LTCH PPS, Medicare will only pay for days for which the beneficiary has coverage until the short-stay outlier threshold is exceeded. (*See* section IV.C.4.b.) Therefore, if the Medicare payment was for a short-stay outlier case (§ 412.529) that was less than the full LTC–DRG payment amount because the beneficiary had insufficient remaining Medicare days, the LTCH could also charge the beneficiary for services delivered on those uncovered days. (§ 412.507).

Since the origin of the Medicare system, the intent of our regulations has been to set limits on beneficiary liability and to clearly establish the circumstances under which the beneficiary would be required to assume responsibility for payment, that is, upon exhausting benefits described in 42 CFR part 409, subpart F. The discussion in the August 30, 2002, final rule was not meant to establish rates or payments for, or define, Medicare-eligible expenses. While we regulate beneficiary liability for coinsurance and deductibles for hospital stays that are covered by Medicare, payments from Medigap insurers to providers for inpatient hospital coverage after Medicare benefits are exhausted are not regulated by us. Furthermore, regulations beginning at § 403.200 and the 1991 National Association of Insurance Commissioners (NAIC) Model Regulation for Medicare Supplemental Insurance, which was incorporated by reference into section 1882 of the Act, govern the relationship between Medigap insurers and beneficiaries.

E. Health Insurance Portability and Accountability Act Compliance

We note that as of October 16, 2002, a LTCH that was required to comply with the Administrative Simplification Standards under the Health Insurance Portability and Accountability Act (HIPAA) (Pub. L. 104–191) and that had not obtained an extension in compliance with the Administrative Compliance Act (Pub. L. 107–105) is obligated to comply with the standards for submitting claim forms to the LTCH's Medicare fiscal intermediary (45 CFR 162.1002 and 45 CFR 162.1102). Beginning October 16, 2003, LTCHs that obtained an extension and that are required to comply with the HIPAA Administrative Simplification Standards must start submitting electronic claims in compliance with the HIPAA regulations cited above, among others.

II. Summary of Major Contents of This Proposed Rule

We are proposing an annual update of the payment rates for the Medicare PPS for inpatient hospital services provided by LTCHs for the 2005 LTCH PPS rate year. (The annual update of the LTC–DRG classifications and relative weights for FY 2005 remains linked to the annual adjustments of the acute care hospital inpatient DRG system and will be effective October 1, 2004.)

We are proposing an outlier threshold for July 1, 2004, through June 30, 2005, derived from the LTCH PPS rate year calculations.

As discussed in section I.B.2. of this preamble, we are proposing a change in the procedure for counting the days in the inpatient average length of stay for hospitals to qualify as LTCHs.

In section I.B.3. of this preamble, we discuss and clarify existing policies regarding the classification of a satellite facility, or a remote location, of a LTCH as an independent LTCH and propose new policies for certain satellite facilities and remote locations.

In section IV.C.4.c. of this preamble, we are proposing to revise existing interrupted stay policy applicable under the LTCH PPS.

III. Long-Term Care Diagnosis-Related Group (LTC–DRG) Classifications and Relative Weights

(If you choose to comment on issues in this section, please include the caption "LTC–DRG CLASSIFICATIONS AND RELATIVE WEIGHTS" at the beginning of your comments.)

A. Background

Section 123 of Pub. L. 106–113 specifically requires that the PPS for LTCHs be a per discharge system with a DRG-based patient classification system reflecting the differences in patient resources and costs in LTCHs while maintaining budget neutrality. Section 307(b)(1) of Pub. L. 106–554 modified the requirements of section 123 of Pub. L. 106–113 by specifically requiring that the Secretary examine "the feasibility and the impact of basing payment under such a system [the LTCH PPS] on the use of existing (or refined) hospital DRGs that have been modified to account for different resource use of LTCH patients as well as the use of the most recently available hospital discharge data."

In accordance with section 307(b)(1) of Pub. L. 106–554 and § 412.515 of our existing regulations, the LTCH PPS uses information from LTCH patient records to classify patient cases into distinct LTC–DRGs based on clinical characteristics and expected resource needs. The LTC–DRGs used as the patient classification component of the LTCH PPS correspond to the hospital inpatient DRGs in the IPPS. We apply weights to the existing hospital inpatient DRGs to account for the difference in resource use by patients exhibiting the case complexity and multiple medical problems characteristic of LTCHs.

In a departure from the IPPS, we use low volume LTC–DRGs (less than 25

LTCH cases) in determining the LTC–DRG weights, since LTCHs do not typically treat the full range of diagnoses as do acute care hospitals. In order to deal with the large number of low volume DRGs (all DRGs with fewer than 25 cases), we group low volume DRGs into 5 quintiles based on average charge per discharge. (A listing of the composition of low volume quintiles appears in the August 30, 2002, LTCH PPS final rule at 67 FR 55986.) We also take into account adjustments to payments for cases in which the stay at the LTCH is five-sixths of the geometric average length of stay and classify these cases as short-stay outlier cases. (A detailed discussion of the application of the Lewin Group model that was used to develop the LTC–DRGs appears in the August 30, 2002 LTCH PPS final rule at 67 FR 55978.)

B. Patient Classifications Into DRGs

Generally, under the LTCH PPS, Medicare payment is made at a predetermined specific rate for each discharge; that payment varies by the LTC–DRG to which a beneficiary's stay is assigned. Cases are classified into LTC–DRGs for payment based on the following six data elements:

(1) Principal diagnosis.
(2) Up to eight additional diagnoses.
(3) Up to six procedures performed.
(4) Age.
(5) Sex.
(6) Discharge status of the patient.

Upon the discharge of the patient from a LTCH, the LTCH must assign appropriate diagnosis and procedure codes from the International Classification of Diseases, Ninth Revision, Clinical Modification (ICD–9–CM). As of October 16, 2002, a LTCH that was required to comply with the HIPAA Administrative Simplification Standards and that had not obtained an extension in compliance with the Administrative Compliance Act (Pub. L. 107–105) is obligated to comply with the standards at 45 CFR 162.1002 and 45 CFR 162.1102. Completed claim forms are to be submitted to the LTCH's Medicare fiscal intermediary.

Medicare fiscal intermediaries enter the clinical and demographic information into their claims processing systems and subject this information to a series of automated screening processes called the Medicare Code Editor (MCE). These screens are designed to identify cases that require further review before assignment into a DRG can be made. During this process, the following types of cases are selected for further development:

• Cases that are improperly coded. (For example, diagnoses are shown that are inappropriate, given the sex of the patient. Code 68.6, Radical abdominal hysterectomy, would be an inappropriate code for a male.)

• Cases including surgical procedures not covered under Medicare. (For example, organ transplant in a nonapproved transplant center.)

• Cases requiring more information. (For example, ICD–9–CM codes are required to be entered at their highest level of specificity. There are valid 3-digit, 4-digit, and 5-digit codes. That is, code 136.3, Pneumocystosis, contains all appropriate digits, but if it is reported with either fewer or more than 4 digits, the claim will be rejected by the MCE as invalid.)

• Cases with principal diagnoses that do not usually justify admission to the hospital. (For example, code 437.9, Unspecified cerebrovascular disease. While this code is valid according to the ICD–9–CM coding scheme, a more precise code should be used for the principal diagnosis.)

After screening through the MCE, each claim will be classified into the appropriate LTC–DRG by the Medicare LTCH GROUPER. The LTCH GROUPER is specialized computer software based on the same GROUPER used by the IPPS. The GROUPER software was developed as a means of classifying each case into a DRG on the basis of diagnosis and procedure codes and other demographic information (age, sex, and discharge status). Following the LTC–DRG assignment, the Medicare fiscal intermediary will determine the prospective payment by using the Medicare PRICER program, which accounts for hospital-specific adjustments. As provided for under the IPPS, we provide an opportunity for the LTCH to review the LTC–DRG assignments made by the fiscal intermediary and to submit additional information within a specified timeframe (§ 412.513(c)).

The GROUPER is used both to classify past cases in order to measure relative hospital resource consumption to establish the DRG weights and to classify current cases for purposes of determining payment. The records for all Medicare hospital inpatient discharges are maintained in the MedPAR file. The data in this file are used to evaluate possible DRG classification changes and to recalibrate the DRG weights during our annual update. DRG weights are based on data for the population of LTCH discharges, reflecting the fact that LTCH patients represent a different patient-mix than patients in short-term acute care hospitals.

C. Organization of DRGs

The DRGs are organized into 25 Major Diagnostic Categories (MDCs), most of which are based on a particular organ system of the body; the remainder involve multiple organ systems (such as MDC 22, Burns). Accordingly, the principal diagnosis determines MDC assignment. Within most MDCs, cases are then divided into surgical DRGs and medical DRGs. Surgical DRGs are assigned based on a surgical hierarchy that orders operating room (O.R.) procedures or groups of O.R. procedures by resource intensity. The GROUPER does not recognize all ICD–9–CM procedure codes as procedures that affect DRG assignment, that is, procedures which are not surgical (for example, EKG), or minor surgical procedures (for example, 86.11, Biopsy of skin and subcutaneous tissue).

The medical DRGs are generally differentiated on the basis of diagnosis. Both medical and surgical DRGs may be further differentiated based on age, sex, discharge status, and presence or absence of complications or comorbidities (CC). We note that CCs are defined by certain secondary diagnoses not related to, or not inherently a part of, the disease process identified by the principal diagnosis. (For example, the GROUPER would not recognize a code from the 800.0x series, Skull fracture, as a CC when combined with principal diagnosis 850.4, Concussion with prolonged loss of consciousness, without return to preexisting conscious level.) In addition, we note that the presence of additional diagnoses does not automatically generate a CC, as not all DRGs recognize a comorbid or complicating condition in their definition. (For example, DRG 466, Aftercare without History of Malignancy as Secondary Diagnosis, is based solely on the principal diagnosis, without consideration of additional diagnoses for DRG determination.)

In its June 2000 Report to Congress, MedPAC recommended that the Secretary "* * * improve the hospital inpatient prospective payment system by adopting, as soon as practicable, diagnosis-related group refinements that more fully capture differences in severity of illness among patients." (Recommendation 3A, p. 63) We have determined it is not practical at this time to develop a refinement to inpatient hospital DRGs based on severity due to time and resource requirements. However, this does not preclude us from development of a severity-adjusted DRG refinement in the future. That is, a refinement to the list of comorbidities and complications could be incorporated into the existing DRG structure. It is also possible a more comprehensive severity adjusted structure may be created if a new code set is adopted. That is, if ICD–9–CM is replaced by ICD–10–CM (for diagnostic coding) and ICD–10–PCS (for procedure coding) or by other code sets, a severity concept may be built into the resulting DRG assignments. Of course any change to the code set would be adopted through the process established in the HIPAA Administrative Simplification Standards provisions.

D. Update of LTC–DRGs

For FY 2004, the LTC–DRG patient classification system was based on LTCH data from the FY 2002 MedPAR file, which contained hospital bills data from the December 2002 update. The patient classification system consisted of 518 DRGs that formed the basis of the FY 2004 LTCH PPS GROUPER. The 518 LTC–DRGs included two "error DRGs". As in the IPPS, we included two error DRGs in which cases that cannot be assigned to valid DRGs will be grouped. These two error DRGs are DRG 469 (Principal Diagnosis Invalid as a Discharge Diagnosis) and DRG 470 (Ungroupable). (*See* the August 1, 2001, Medicare Program final rule, Changes to the Hospital Inpatient Prospective Payment Systems and Rates and Costs of Graduate Medical Education; Fiscal Year 2002 Rates (66 FR 40062).) The other 516 LTC–DRGs are the same DRGs used in the IPPS GROUPER for FY 2004 (Version 21.0).

In the health care industry, annual changes to the ICD–9–CM codes are effective for discharges occurring on or after October 1 each year. Thus, the manual and electronic versions of the GROUPER software, which are based on the ICD–9–CM codes, are also revised annually and effective for discharges occurring on or after October 1 each year. As discussed earlier, the patient classification system for the LTCH PPS (LTC–DRGs) is based on the IPPS patient classification system (CMS–DRGs), which is updated annually and effective for discharges occurring on or after October 1 through September 30 each year. The updated DRGs and GROUPER software are based on the latest revision to the ICD–9–CM codes, which are published annually in the IPPS proposed rule and final rule. The new or revised ICD–9–CM codes are not used by the industry for either the IPPS or the LTCH PPS until the beginning of the next Federal fiscal year (effective for discharges occurring on or after October 1 through September 30). (The use of the ICD–9–CM codes in this manner is consistent with current usage and the HIPAA regulations.) October 1 is also when the changes to the CMS–DRGs and the next version of the GROUPER software becomes effective.

As indicated in the June 3, 2002, LTCH PPS and the August 1, 2003, IPPS final rules (68 FR 34122 and 68 FR 45374), we make the annual update to the LTCH PPS effective from July 1 through June 30 each year. As a result, the LTCH PPS uses two GROUPERS during the course of a 12-month period: one GROUPER for 3 months (from July 1 through September 30); and an updated GROUPER for 9 months (from October 1 through June 30). The need to use two GROUPERs is based upon the October 1 effective date of the updated ICD–9–CM coding system. As previously discussed, new ICD–9–CM codes may result in changes to the structure of the DRGs. In order for the industry to be on the same schedule (for both the IPPS and the LTCH PPS) for the use of the most current ICD–9–CM codes, it is necessary for us to apply two GROUPER programs to the LTCH PPS. LTCHs will continue to code diagnosis and procedures using the most current version of the ICD–9–CM coding system.

Currently, for Federal FY 2004, we are using Version 21.0 of the GROUPER software for both the IPPS and the LTCH PPS. Discharges beginning on October 1, 2003, and before October 1, 2004 (Federal FY 2004), will use Version 21.0 of the GROUPER software for both the IPPS and the LTCH PPS. Thus, changes to the CMS–DRGs (the DRGs on which the LTC–DRGs are based) and their relative weights, as well as the LTC–DRGs and their relative weights, that will be effective for October 1, 2004, through September 30, 2005, will be presented in the IPPS FY 2005 proposed rule that will be published in the **Federal Register** in the spring of 2004 and finalized in a final rule to be published by August 1, 2004. Accordingly, we will notify LTCHs of any revised LTC–DRG relative weights based on the final DRGs and the applicable GROUPER version for the IPPS that will be effective October 1, 2004.

E. ICD–9–CM Coding System

1. Uniform Hospital Discharge Data Set (UHDDS) Definitions

Because the assignment of a case to a particular LTC–DRG will help determine the amount that will be paid for the case, it is important that the coding is accurate. Classifications and terminology used in the LTCH PPS are consistent with the ICD–9–CM and the UHDDS, as recommended to the Secretary by the National Committee on Vital and Health Statistics ("Uniform Hospital Discharge Data: Minimum Data Set, National Center for Health Statistics, April 1980") and as revised in 1984 by the Health Information Policy Council (HIPC) of the U.S. Department of Health and Human Services.

We point out that the ICD–9–CM coding terminology and the definitions of principal and other diagnoses of the UHDDS are consistent with the requirements of the HIPAA Administrative Simplification Act of 1996 (45 CFR Part 162). Furthermore, the UHDDS has been used as a standard for the development of policies and programs related to hospital discharge statistics by both governmental and nongovernmental sectors for over 30 years. In addition, the following definitions (as described in the 1984 Revision of the UHDDS, approved by the Secretary of Health and Human Services for use starting January 1986) are requirements of the ICD–9–CM coding system, and have been used as a standard for the development of the CMS–DRGs:

- Diagnoses include all diagnoses that affect the current hospital stay.
- Principal diagnosis is defined as the condition established after study to be chiefly responsible for occasioning the admission of the patient to the hospital for care.
- Other diagnoses (also called secondary diagnoses or additional diagnoses) are defined as all conditions that coexist at the time of admission, that develop subsequently, or that affect the treatment received or the length of stay or both. Diagnoses that relate to an earlier episode of care that have no bearing on the current hospital stay are excluded.
- All procedures performed will be reported. This includes those that are surgical in nature, carry a procedural risk, carry an anesthetic risk, or require specialized training.

We provide LTCHs with a 60-day window after the date of the notice of the initial LTC–DRG assignment to request review of that assignment. Additional information may be provided by the LTCH to the fiscal intermediary as part of that review.

2. Maintenance of the ICD–9–CM Coding System

The ICD–9–CM Coordination and Maintenance (C&M) Committee is a Federal interdepartmental committee, co-chaired by the National Center for Health Statistics (NCHS) and CMS, that is charged with maintaining and updating the ICD–9–CM system. The C&M Committee is jointly responsible for approving coding changes, and developing errata, addenda, and other modifications to the ICD–9–CM to reflect newly developed procedures and technologies and newly identified diseases. The C&M Committee is also responsible for promoting the use of Federal and non-Federal educational programs and other communication techniques with a view toward standardizing coding applications and upgrading the quality of the classification system.

The NCHS has lead responsibility for the ICD–9–CM diagnosis codes included in the Tabular List and Alphabetic Index for Diseases, while CMS has lead responsibility for the ICD–9–CM procedure codes included in the Tabular List and Alphabetic Index for Procedures.

The C&M Committee encourages participation by health-related organizations in the above process and holds public meetings for discussion of educational issues and proposed coding changes twice a year at the CMS Central Office located in Baltimore, Maryland. The agenda and dates of the meetings can be accessed on the CMS Web site at: *http://www.cms.gov/paymentsystems/icd9*.

All changes to the ICD–9–CM coding system affecting DRG assignment are addressed annually in the IPPS proposed and final rules. Because the DRG-based patient classification system for the LTCH PPS is based on the IPPS DRGs, these changes will also affect the LTCH PPS LTC–DRG patient classification system.

As discussed above, the ICD–9–CM coding changes that have been adopted by the C&M Committee become effective at the beginning of each Federal fiscal year, October 1. Regardless of the annual update of the LTCH PPS on July 1 of each year, coders will use the most current updated ICD–9–CM coding book, which is effective from October 1 through September 30 of each year. This means that coders and LTCHs that use the updated ICD–9–CM coding system will be on the same schedule (effective October 1) as the rest of the health care industry. The newest version of ICD–9–CM is not available for use until October 1 of each year, which is 5 months after the date that we publish the LTCH annual payment rate update final rule. The new codes on which the LTC–DRGs are based will go into effect and be available for use for discharges occurring on or after October 1 through September 30 of each year. This annual schedule of the revision to the ICD–9–CM coding system and the change of the ICD–9–CM coding books or electronic coding programs has been in effect since the adoption of Revision 9 of the ICD in 1979.

Of particular note to LTCHs will be the invalid diagnosis codes (Table 6C) and the invalid procedure codes (Table 6D) located in the annual proposed and final rules for the IPPS. Claims with invalid codes will not be processed by the Medicare claims processing system.

3. Coding Rules and Use of ICD–9–CM Codes in LTCHs

We emphasize the need for proper coding by LTCHs. Inappropriate coding of cases can adversely affect the uniformity of cases in each LTC-DRG and produce inappropriate weighting factors at recalibration. We continue to urge LTCHs to focus on improved coding practices. Because of concerns raised by LTCHs concerning correct coding, we have asked the American Hospital Association (AHA) to provide additional clarification or instruction on proper coding in the LTCH setting. The AHA will provide this instruction via their established process of addressing questions through their publication "Coding Clinic for ICD–9–CM". Written questions or requests for clarification may be addressed to the Central Office on ICD–9–CM, American Hospital Association, One North Franklin, Chicago, IL 60606. A form for the question(s) is available to be downloaded and mailed on AHA's Web site at: *http://www.ahacentraloffice.org*. In addition, current coding guidelines are available at the National Center for Health Statistics (NCHS) Web site: *www.cdc.gov/nchs.icd9.htm*.

In conjunction with the cooperating parties (AHA, the American Health Information Management Association (AHIMA), and NCHS), we have reviewed actual medical records and are concerned about the quality of the documentation under the LTCH PPS, as was the case at the beginning of the IPPS. We fully believe that, with experience, the quality of the documentation and coding will improve, just as it did for the IPPS. As noted above, the cooperating parties have plans to assist their members with improvement in documentation and coding issues for the LTCHs through specific questions and coding guidelines. The importance of good documentation is emphasized in the revised ICD–9–CM Official Guidelines for Coding and Reporting (October 1, 2002): "A joint effort between the attending physician and coder is essential to achieve complete and accurate documentation, code assignment, and reporting of diagnoses and procedures. The importance of consistent, complete documentation in the medical record cannot be overemphasized. Without such documentation, the application of all coding guidelines is a difficult, if not impossible, task. (Coding Clinic for ICD–9–CM, Fourth Quarter 2002, page 115)

To improve medical record documentation, LTCHs should be aware that if the patient is being admitted for continuation of treatment of an acute or chronic condition, guidelines at Section I.B.10 of the Coding Clinic for ICD–9–CM, Fourth Quarter 2002 (page 129) are applicable concerning selection of principal diagnosis. To clarify coding advice issued in the August 30, 2002, final rule (67 FR 55979–55981), we would like to point out that at Guideline I.B.12, Late Effects, a late effect is considered to be the residual effect (condition produced) after the acute phase of an illness or injury has terminated (Coding Clinic for ICD–9–CM, Fourth Quarter 2002, page 129). Regarding whether a LTCH should report the ICD–9–CM code(s) for an unresolved acute condition instead of the code(s) for late effect of rehabilitation, we emphasize that each case must be evaluated on its unique circumstances and coded appropriately. Depending on the documentation in the medical record, either a code reflecting the acute condition or rehabilitation could be appropriate in a LTCH.

Since implementation of the LTCH PPS, our Medicare fiscal intermediaries have been conducting training and providing assistance to LTCHs in correct coding. We have also issued manuals containing procedures as well as coding instructions to LTCHs and fiscal intermediaries. We will continue to conduct such training and provide guidance on an as-needed basis. We also refer readers to the detailed discussion on correct coding practices in the August 30, 2002, LTCH PPS final rule (67 FR 55979–55981). Additional coding instructions and examples will be published in Coding Clinic for ICD–9–CM.

F. The Method for Updating the LTC-DRG Relative Weights

As discussed in the June 6, 2003, LTCH PPS final rule (68 FR 34131), under the LTCH PPS each LTCH will receive a payment that represents an appropriate amount for the efficient delivery of care to Medicare patients. The system must be able to account adequately for each LTCH's case-mix in order to ensure both fair distribution of Medicare payments and access to adequate care for those Medicare patients whose care is more costly. Therefore, in accordance with section

412.523(c), we adjust the standard Federal PPS rate by the LTC–DRG relative weights in determining payment to LTCHs for each case.

Under this payment system, relative weights for each LTC–DRG are a primary element used to account for the variations in cost per discharge and resource utilization among the payment groups (section 412.515). To ensure that Medicare patients who are classified to each LTC–DRG have access to an appropriate level of services and to encourage efficiency, we calculate a relative weight for each LTC–DRG that represents the resources needed by an average inpatient LTCH case in that LTC–DRG. For example, cases in a LTC–DRG with a relative weight of 2 will, on average, cost twice as much as cases in a LTC–DRG with a weight of 1.

As we discussed in the August 1, 2003, IPPS final rule (68 FR 45374–45384), the LTC–DRG relative weights effective under the LTCH PPS for Federal FY 2004 were calculated using the December 2002 update of FY 2002 MedPAR data and Version 21.0 of the CMS GROUPER software. We use total days and total charges in the calculation of the LTC–DRG relative weights.

By nature, LTCHs often specialize in certain areas, such as ventilator-dependent patients and rehabilitation and wound care. Some case types (DRGs) may be treated, to a large extent, in hospitals that have, from a perspective of charges, relatively high (or low) charges. Such distribution of cases with relatively high (or low) charges in specific LTC–DRGs has the potential to inappropriately distort the measure of average charges. To account for the fact that cases may not be randomly distributed across LTCHs, we use a hospital-specific relative value method to calculate relative weights. We believe this method removes this hospital-specific source of bias in measuring average charges. Specifically, we reduce the impact of the variation in charges across providers on any particular LTC–DRG relative weight by converting each LTCH's charge for a case to a relative value based on that LTCH's average charge. (*See* the August 1, 2003, IPPS final rule (68 FR 45376) for further information on the hospital-specific relative value methodology.)

In order to account for LTC–DRGs with low volume (that is, with fewer than 25 LTCH cases), we grouped those low volume LTC–DRGs into one of five categories (quintiles) based on average charges, for the purposes of determining relative weights. For FY 2004 based on the FY 2002 MedPAR data, we identified 173 LTC–DRGs that contained between 1 and 24 cases. This list of low volume LTC–DRGs was then divided into one of the five low volume quintiles, each containing a minimum of 34 LTC–DRGs (173/5 = 34 with 1 LTC–DRG as a remainder). Each of the low volume LTC–DRGs grouped to a specific quintile received the same relative weight and average length of stay using the formula applied to the regular LTC–DRGs (25 or more cases), as described below. (*See* the August 1, 2003, final rule (68 FR 45376–45380) for further explanation of the development and composition of each of the five low volume quintiles for FY 2004.)

After grouping the cases in the appropriate LTC–DRG, we calculate the relative weights by first removing statistical outliers and cases with a length of stay of 7 days or less. Next, we adjust the number of cases in each LTC–DRG for the effect of short-stay outlier cases under § 412.529. The short-stay adjusted discharges and corresponding charges were used to calculate "relative adjusted weights" in each LTC–DRG using the hospital-specific relative value method described above. (See August 1, 2003, final rule (68 FR 45376–45385) for further details on the steps for calculating the LTC–DRG relative weights.)

We also adjust the LTC–DRG relative weights to account for nonmonotonically increasing relative weights. That is, we make an adjustment if cases classified to the LTC–DRG "with comorbidities (CCs)" of a "with CC"/ "without CC" pair had a lower average charge than the corresponding LTC–DRG "without CCs" by assigning the same weight to both LTC–DRGs in the "with CC"/"without CC" pair. (*See* August 1, 2003, final rule, 68 FR 45381–45382.) In addition, of the 518 LTC–DRGs in the LTCH PPS for FY 2004, based on the FY 2002 MedPAR data, we identified 167 LTC–DRGs for which there were no LTCH cases in the database. That is, no patients who would have been classified to those DRGs were treated in LTCHs during FY 2002 and, therefore, no charge data were reported for those DRGs. Thus, in the process of determining the relative weights of LTC–DRGs, we were unable to determine weights for these 167 LTC–DRGs using the method described above. However, since patients with a number of the diagnoses under these LTC–DRGs may be treated at LTCHs beginning in FY 2004, we assigned relative weights to each of the 167 "no volume" LTC–DRGs based on clinical similarity and relative costliness to one of the remaining 351 (518 − 167 = 351) LTC–DRGs for which we were able to determine relative weights, based on the FY 2002 claims data. (A list of the no volume LTC–DRGs and further explanation of their relative weight assignment can be found in the August 1, 2003, IPPS final rule (68 FR 45374–45385).)

Furthermore, for FY 2004 we established LTC–DRG relative weights of 0.0000 for heart, kidney, liver, lung, pancreas, and simultaneous pancreas/ kidney transplants (LTC–DRGs 103, 302, 480, 495, 512 and 513, respectively) because Medicare will only cover these procedures if they are performed at a hospital that has been certified for the specific procedures by Medicare and presently no LTCH has been so certified. If in the future, however, a LTCH applies for certification as a Medicare-approved transplant center, we believe that the application and approval procedure would allow sufficient time for us to propose appropriate weights for the LTC–DRGs effected. At the present time, though, we include these six transplant LTC–DRGs in the GROUPER program for administrative purposes. As the LTCH PPS uses the same GROUPER program for LTCHs as is used under the IPPS, removing these DRGs would be administratively burdensome.

As we stated in the August 1, 2003, IPPS final rule, we will continue to use the same LTC–DRGs and relative weights for FY 2004 until October 1, 2004. Accordingly, Table 3 in the Addendum to this proposed rule lists the LTC–DRGs and their respective relative weights and arithmetic mean length of stay that we will continue to use for the period of July 1, 2004, through September 30, 2004. (This table is the same as Table 3 of the Addendum to the August 1, 2003, IPPS final rule (68 FR 45650–45658), except that it includes the proposed five-sixth of the average length of stay for short-stay outliers under § 412.529.) As we noted earlier, the final DRGs and GROUPER for FY 2005 that will be used for the IPPS and the LTCH PPS, effective October 1, 2004, will be presented in the IPPS FY 2005 proposed and final rule in the **Federal Register**.

Accordingly, we will notify LTCHs of the revised LTC–DRG relative weights for use in determining payments for discharges occurring between October 1, 2004, and September 30, 2005, based on the final DRGs and the applicable GROUPER version that will be published in the IPPS rule by August 1, 2004.

IV. Proposed Changes to the LTCH PPS Rates and Proposed Changes in Policy for the 2005 LTCH PPS Rate Year

(If you choose to comment on issues in this section, please include the caption

"PROPOSED CHANGES TO LTCH PPS RATES AND POLICY FOR THE 2005 LTCH PPS RATE YEAR" at the beginning of your comments.)

A. Overview of the Development of the Payment Rates

The LTCH PPS was effective for a LTCH's first cost reporting period beginning on or after October 1, 2002. Effective with that cost reporting period, LTCHs are paid, during a 5-year transition period, on the basis of an increasing proportion of the LTCH PPS Federal rate and a decreasing proportion of a hospital's payment under reasonable cost-based payment system, unless the hospital makes a one-time election to receive payment based on 100 percent of the Federal rate (*see* § 412.533). New LTCHs (as defined at § 412.23(e)(4)) are paid based on 100 percent of the Federal rate, with no phase-in transition payments.

The basic methodology for determining LTCH PPS Federal prospective payment rates is set forth in the regulations at §§ 412.515 through 412.532. Below we discuss the proposed factors used to update the LTCH PPS standard Federal rate for the 2005 LTCH PPS rate year that will be effective for LTCHs discharges occurring on or after July 1, 2004, through June 30, 2005.

When we implemented the LTCH PPS in the August 30, 2002, final rule (67 FR 56029–56031), we computed the LTCH PPS standard Federal payment rate for FY 2003 by updating the best available (FY 1998 or FY 1999) Medicare inpatient operating and capital costs per case data, using the excluded hospital market basket.

Section 123(a)(1) of Pub. L. 106–113 requires that the PPS developed for LTCHs be budget neutral. Therefore, in calculating the standard Federal rate under § 412.523(d)(2), we set total estimated PPS payments equal to estimated payments that would have been made under the reasonable cost-based payment methodology had the PPS for LTCHs not been implemented. Section 307(a) of Pub. L. 106–554 specified that the increases to the hospital-specific target amounts and cap on the target amounts for LTCHs for FY 2002 provided for by section 307(a)(1) of Pub. L. 106–554 shall not be taken into account in the development and implementation of the LTCH PPS. In addition, the statute as amended by section 122 of Pub. L. 106–113 provides for enhanced bonus payments for LTCHs for 2 years, FY 2001 and FY 2002. Furthermore, as specified at § 412.523(d)(1), the standard Federal rate is reduced by an adjustment factor to account for the estimated proportion of outlier payments under the LTCH PPS to total LTCH PPS payments (8 percent). For further details on the development of the FY 2003 standard Federal rate, *see* the August 30, 2002, final rule (67 FR 56027–56037) and for the 2004 LTCH PPS rate year rate, *see* the June 6, 2003, final rule (68 FR 34122–34190).

Under the existing regulations at § 412.523(c)(3)(ii), we update the standard Federal rate annually to adjust for the most recent estimate of the projected increases in prices for LTCH inpatient hospital services.

B. Proposed Update to the Standard Federal Rate for the 2005 LTCH PPS Rate Year

As established in the June 6, 2003, final rule (68 FR 34122), based on the most recent estimate of the excluded hospital with capital market basket, adjusted to account for the change in the LTCH PPS rate year update cycle, the LTCH PPS standard Federal rate effective from July 1, 2003, through June 30, 2004, (the 2004 LTCH PPS rate year), is $35,726.18.

In the discussion that follows, we explain how we developed the proposed standard Federal rate for the 2005 LTCH PPS rate year. The proposed standard Federal rate for the 2005 LTCH PPS rate year would be calculated based on the proposed update factor of 1.029. Thus, we estimate that the proposed standard Federal rate for the 2005 LTCH PPS rate year would increase 2.9 percent compared to the 2004 LTCH PPS rate year standard Federal rate.

1. Proposed Standard Federal Rate Update

Under § 412.523, the annual update to the LTCH PPS standard Federal rate must be equal to the percentage change in the excluded hospital with capital market basket (described in further detail below). As we discussed in the August 30, 2002, final rule (67 FR 56087), in the future we may propose to develop a framework to update payments to LTCHs that would account for other appropriate factors that affect the efficient delivery of services and care provided to Medicare patients. As we discussed in the June 6, 2003, final rule (68 FR 34122), because the LTCH PPS has only been implemented for less than 2 years (for cost reporting periods beginning on or after October 1, 2002), we have not yet collected sufficient data to allow for the analysis and development of an update framework under the LTCH PPS. Therefore, we are not proposing an update framework for the 2005 LTCH PPS rate year in this proposed rule. However, we noted that a conceptual basis for the proposal of developing an update framework in the future can be found in Appendix B of the August 30, 2002, final rule (67 FR 56086–56090).

a. Description of the Proposed Market Basket for LTCHs for the 2005 LTCH PPS Rate Year

A market basket has historically been used in the Medicare program to account for price increases of the services furnished by providers. The market basket used for the LTCH PPS includes both operating and capital-related costs of LTCHs because the LTCH PPS uses a single payment rate for both operating and capital-related costs. The development of the LTCH PPS standard Federal rate is discussed in further detail in the August 30, 2002, final rule (67 FR 56027–56037).

Under the reasonable cost-based payment system, the excluded hospital market basket was used to update the hospital-specific limits on payment for operating costs of LTCHs. The excluded hospital market basket is based on operating costs from FY 1992 cost report data and includes data from Medicare-participating long-term care, rehabilitation, psychiatric, cancer, and children's hospitals. Since LTCHs' costs are included in the excluded hospital market basket, this market basket index, in part, also reflects the costs of LTCHs. However, in order to capture the total costs (operating and capital-related) of LTCHs, we added a capital component to the excluded hospital market basket for use under the LTCH PPS. We refer to this index as the excluded hospital with capital market basket.

As we discussed in the August 30, 2002, final rule (67 FR 56016 and 56086), beginning with the implementation of the LTCH PPS in FY 2003, the excluded hospital with capital market basket based on FY 1992 Medicare cost report data has been used for updating payments to LTCHs. In the June 6, 2003, final rule (68 FR 34137), we revised and rebased the excluded hospital with capital market basket, using more recent data, that is, using FY 1997 base year data beginning with the 2004 LTCH PPS rate year. (For further details on the development of the FY 1997-based LTCH PPS market basket, *see* the June 6, 2003, final rule (68 FR 34134–34137).

In the August 30, 2002, LTCH PPS final rule (67 FR 56016 and 56085–56086), we discussed why we believe the excluded hospital with capital market basket provides a reasonable measure of the price changes facing LTCHs. However, as we discussed in the June 6, 2003, final rule (68 FR 34137), we have been researching the feasibility of developing a market basket specific to LTCH services. This research has included analyzing data sources for cost category weights, specifically the Medicare cost reports, and investigating other data sources on cost, expenditure, and price information specific to LTCHs. Based on this research, we did not develop a market basket specific to LTCH services.

As we also discussed in the June 6, 2003, final rule (68 FR 34137), our analysis of the Medicare cost reports indicates that the distribution of costs among major cost report categories (wages, pharmaceuticals, capital) for LTCHs is not substantially different from the 1997-based excluded hospital with capital market basket. Data on other major cost categories (benefits, blood, contract labor) that we would like to analyze were excluded by many LTCHs in their Medicare cost reports. An analysis based on only the data available to us for these cost categories presented a potential problem since no other major cost category weight would be based on LTCH data.

Furthermore, as we also discussed in that same final rule (68 FR 34137), we conducted a sensitivity analysis of annual percent changes in the market basket when the weights for wages, pharmaceuticals, and capital in LTCHs were substituted into the excluded hospital with capital market basket. Other cost categories were recalibrated using ratios available from the IPPS market basket. On average between FY 1995 and FY 2002, the excluded hospital with capital market basket shows increases at nearly the same average annual rate (2.9 percent) as the market basket with LTCH weights for wages, pharmaceuticals, and capital (2.8 percent). This difference is less than the 0.25 percentage point criterion that determines whether a forecast error adjustment is warranted under the IPPS update framework.

We continue to believe that an excluded hospital with capital market basket adequately reflects the price changes facing LTCHs. We continue to solicit comments about issues particular to LTCHs that should be considered in relation to the FY 1997-based excluded hospital with capital market basket and to encourage suggestions for additional data sources that may be available. Accordingly, in this proposed rule, we are proposing to use the FY 1997-based excluded hospital with capital market basket as the LTCH PPS market basket for determining the proposed update to the LTCH PPS standard Federal rate for the 2005 LTCH PPS rate year.

b. Proposed LTCH Market Basket Increase for the 2005 LTCH Rate Year

As we discussed in the June 6, 2003, final rule (68 FR 34137), for LTCHs paid under the LTCH PPS, we stated that the 2004 rate year update would apply to discharges occurring from July 1, 2003, through June 30, 2004. Because we changed the timeframe of the LTCH PPS standard Federal rate annual update from October 1 to July 1, as we explained in that same final rule, we calculated an update factor that reflected that change in the update cycle. For the update to the 2004 LTCH PPS rate year, we calculated the estimated increase between FY 2003 and the 2004 LTCH PPS rate year (July 1, 2003, through June 30, 2004). Accordingly, based on Global Insight's forecast of the revised and rebased FY 1997-based excluded hospital with capital market basket using data from the fourth quarter of 2002, we used a market basket update of 2.5 percent for the 2004 LTCH PPS rate year (68 FR 34138).

Consistent with our historical practice of estimating market basket increases based on Global Insight's forecast of the FY 1997-based excluded hospital with capital market basket using more recent data from the third quarter of 2003, we are proposing a 2.9 percent update to the Federal rate for the 2005 LTCH PPS rate year.

In accordance with § 412.523, this update represents the most recent estimate of the increase in the excluded hospital with capital market basket for the 2005 LTCH PPS rate year.

2. Proposed Standard Federal Rate for the 2005 LTCH PPS Rate Year

In the June 6, 2003, final rule (68 FR 34140), we established a standard Federal rate of $35,726.18 for the 2004 LTCH PPS rate year. For the 2005 LTCH PPS rate year, we are proposing a standard Federal rate of $36,762.24. Since the proposed 2005 LTCH PPS rate year standard Federal rate has already been adjusted for differences in case-mix, wages, cost-of-living, and high-cost outlier payments, we are not proposing to make any additional adjustments in the proposed standard Federal rate for these factors.

C. Calculation of Proposed LTCH Prospective Payments for the 2005 LTCH PPS Rate Year

The basic methodology for determining prospective payment rates for LTCH inpatient operating and capital-related costs is set forth in § 412.515 through § 412.532. In accordance with § 412.515, we assign appropriate weighting factors to each LTC–DRG to reflect the estimated relative cost of hospital resources used for discharges within that group as compared to discharges classified within other groups. The amount of the prospective payment is based on the standard Federal rate, established under § 412.523, and adjusted for the LTC–DRG relative weights, differences in area wage levels, cost-of-living in Alaska and Hawaii, high-cost outliers, and other special payment provisions (short-stay outliers under § 412.529 and interrupted stays under § 412.531).

In accordance with § 412.533, during the 5-year transition period, payment is based on the applicable transition blend percentage of the adjusted Federal rate and the reasonable cost-based payment rate unless the LTCH makes a one-time election to receive payment based on 100 percent of the Federal rate. A LTCH defined as "new" under § 412.23(e)(4) is paid based on 100 percent of the Federal rate with no blended transition payments (§ 412.533(d)). As discussed in the August 30, 2002 final rule (67 FR 56038) and in accordance with § 412.533(a), the applicable transition blends are as follows:

Cost reporting periods beginning on or after	Federal rate percentage	Reasonable cost-based payment rate percentage
October 1, 2002	20	80
October 1, 2003	40	60
October 1, 2004	60	40
October 1, 2005	80	20
October 1, 2006	100	0

Accordingly, for cost reporting periods beginning during FY 2004 (that is, on or after October 1, 2003, and before September 30, 2004), blended payments under the transition methodology are based on 60 percent of the LTCH's reasonable cost-based payment rate and 40 percent of the adjusted LTCH PPS Federal rate. For cost reporting periods that begin during FY 2005 (that is, on or after October 1, 2004, and before September 30, 2005), blended payments under the transition methodology will be based on 40 percent of the LTCH's reasonable cost-based payment rate and 60 percent of the adjusted LTCH PPS Federal rate.

1. Adjustment for Area Wage Levels

a. Background

Under the authority of section 307(b) of Pub. L. 106–554, we established an adjustment to account for differences in LTCH area wage levels under § 412.525(c) using the labor-related share estimated by the excluded hospital market basket with capital and wage indices that were computed using wage data from inpatient acute care hospitals without regard to reclassification under section 1886(d)(8) or section 1886(d)(10) of the Act. Furthermore, as we discussed in the August 30, 2002, final rule (67 FR 56015–56019), we established a 5-year transition to the full wage adjustment. The applicable wage index phase-in percentages are based on the start of a LTCH's cost reporting period as shown in the following table:

Cost reporting periods beginning on or after	Phase-in percentage of the full wage index
October 1, 2002	⅕ths (20 percent).
October 1, 2003	⅖ths (40 percent).
October 1, 2004	⅗ths (60 percent).
October 1, 2005	⅘ths (80 percent).
October 1, 2006	5⁄5ths (100 percent).

For example, for cost reporting periods beginning on or after October 1, 2004, and before September 30, 2005 (FY 2005), the applicable LTCH wage index value would be three-fifths of the applicable full wage index value without taking into account geographic reclassification under sections 1886(d)(8) and (d)(10) of the Act.

In that same final rule (67 FR 56018), we stated that we would continue to reevaluate LTCH data as they become available and would propose to adjust the phase-in if subsequent data support a change. As we discussed in the June 6, 2003, final rule (68 FR 34140), because the LTCH PPS has only been implemented for less than 2 years, sufficient new data have not been generated that would enable us to conduct a comprehensive reevaluation of the appropriateness of adjusting the phase-in. However, in that same final rule, we explained that we had reviewed the most recent data available at that time and did not find any evidence to support a change in the 5-year phase-in of the wage index.

Because of the recent implementation of the LTCH PPS and the lag time in availability of cost report data, we still do not yet have sufficient new data to allow us to conduct a comprehensive reevaluation of the appropriateness of the phase-in of the wage index adjustment. Again, we have reviewed the most recent data available and did not find any evidence to support a change in the 5-year phase-in of the wage index. Therefore, at this time, we are not proposing to adjust the phase-in of the wage index adjustment in this proposed rule.

b. Wage Index Data

In the June 6, 2003, final rule (68 FR 34142), for the 2004 LTCH PPS rate year, we established that we would use the same data that was used to compute the FY 2003 acute care hospital inpatient wage index without taking into account geographic reclassifications under sections 1886(d)(8) and (d)(10) of the Act because that was the best available data at that time. The acute care hospital inpatient wage index data is also used in the inpatient rehabilitation PPS (IRF PPS), the home health agency PPS (HHA PPS), and the skilled nursing facility PPS (SNF PPS). As we discussed in the August 30, 2002, final rule (67 FR 56019), since hospitals that are excluded from the IPPS are not required to provide wage-related information on the Medicare cost report and we would need to establish instructions for the collection of such LTCH data in order to establish a geographic reclassification adjustment under the LTCH PPS, the wage adjustment established under the LTCH PPS is based on a LTCH's actual location without regard to the urban or rural designation of any related or affiliated provider.

In this proposed rule, we are proposing that for the 2005 LTCH PPS rate year, the same data used to compute the FY 2004 acute care hospital inpatient wage index without taking into account geographic reclassifications under sections 1886(d)(8) and (d)(10) of the Act would be used to determine the applicable wage index values under the LTCH PPS, because these are the most recent available complete data. These data are the same wage data that were used to compute the FY 2003 wage indices currently used under the IPPS and SNF PPS. The proposed LTCH wage index values that would be used for discharges occurring on or after July 1, 2004, through June 30, 2005, are shown in Table 1 (for urban areas) and Table 2 (for rural areas) in the Addendum to this proposed rule.

As noted above, the applicable wage index phase-in percentages are based on the start of a LTCH's cost reporting period beginning on or after October 1st of each year during the 5-year transition period. For cost reporting periods beginning on or after October 1, 2003, and before September 30, 2004 (FY 2004), the labor portion of the proposed standard Federal rate would be adjusted by two-fifths of the applicable LTCH wage index value. Specifically, for a LTCH's cost reporting period beginning during FY 2004, for discharges occurring on or after July 1, 2004, through June 30, 2005, the applicable wage index value would be two-fifths of the full FY 2004 acute care hospital inpatient wage index data, without taking into account geographic reclassifications under sections 1886(d)(8) and (d)(10) of the Act) as shown in Tables 1 and 2 in the Addendum to this proposed rule. Similarly, for cost reporting periods beginning on or after October 1, 2004, and before October 1, 2005 (FY 2005), the labor portion of the proposed standard Federal rate would be adjusted by three-fifths of the applicable LTCH wage index value. Specifically, for a LTCH's cost reporting period beginning during FY 2005, for discharges occurring on or after July 1, 2004, through June 30, 2005, the applicable wage index value would be three-fifths of the full FY 2005 acute care hospital inpatient wage index data, without taking into account geographic reclassification under sections 1886(d)(8) and (d)(10) of the Act as shown in Tables 1 and 2 in the addendum to this proposed rule.

Because the phase-in of the wage index does not coincide with the LTCH PPS rate year (July 1st through June 30th), most LTCHs will experience a change in the wage index phase-in percentages during the LTCH PPS rate year. For example, during the 2005 LTCH PPS rate year, for a LTCH with a January 1st fiscal year, the two-fifths wage index would be applicable for the first 6 months of the 2005 LTCH PPS rate year (July 1, 2004, through December 31, 2004) and the three-fifths wage index would be applicable for the second 6 months of the 2005 LTCH PPS rate year (January 1, 2005, through June 30, 2005). We also note that some providers will still be in the first year of the 5-year phase-in of the LTCH wage index (that is, those LTCHs with cost reporting periods that began during FY 2003 and are ending during the first 3 months of the 2005 LTCH PPS rate year (July 1, 2004, through September 30, 2004). For the remainder of those LTCHs' FY 2003 cost reporting periods, for discharges occurring on or after July 1, 2004, through June 30, 2005, the applicable wage index value would be one-fifth of the full FY 2005 acute care hospital inpatient wage index data, without taking into account geographic reclassification under sections 1886(d)(8) and (d)(10) of the Act as shown in Tables 1 and 2 in the Addendum to this proposed rule.

c. Labor-Related Share

In the August 30, 2002, final rule (67 FR 56016), we established a labor-related share of 72.885 percent based on the relative importance of the labor-related share of operating and capital costs of the excluded hospital with capital market basket based on FY 1992 data. In the June 6, 2003, final rule (68 FR 34142), in conjunction with our revision and rebasing of the excluded hospital with capital market basket from an FY 1992 to an FY 1997 base year, we used a labor-related share that is determined based on the relative importance of the labor-related share of operating costs (wages and salaries, employee benefits, professional fees, postal services, and all other labor-intensive services) and capital costs of the excluded hospital with capital market basket based on FY 1997 data. While we adopted the revised and rebased FY 1997-based LTCH PPS market basket as the LTCH PPS update factor for the 2004 LTCH PPS rate year, we decided not to update the labor-related share under the LTCH PPS pending further analysis. Accordingly, the labor-share for the 2004 LTCH PPS rate year was 72.885 percent.

In the August 1, 2003, IPPS final rule (68 FR 50041–50042), we did not use a revised labor-related share for FY 2004 because we had not yet completed our research into the appropriateness of this updated measure. In that rule, we discussed two methods that we were reviewing for establishing the labor-related share—(1) updating the regression analysis that was done when the IPPS was originally developed and (2) reevaluating the methodology we currently use for determining the labor-related share using the hospital market basket. We also explained that we would continue to explore all options for alternative data and a methodology for determining the labor-related share, and would propose to update the IPPS and excluded hospital labor-related shares, if necessary, once our research is complete.

As we explained in the August 30, 2002, final rule, which implemented the LTCH PPS, the June 6, 2003, LTCH PPS final rule, and the June 9, 2003, high-cost outlier final rule, the LTCH PPS was modeled after the IPPS for short-term, acute care hospitals. Specifically, the LTCH PPS uses the same patient classification system (CMS–DRGs) as the IPPS, and many of the case-level and facility-level adjustments explored or adopted for the LTCH PPS are payment adjustments under the IPPS (that is, wage index, high-cost outliers, and the evaluation of adjustments for indirect teaching costs and the treatment of a disproportionate share of low-income patients).

Furthermore, as discussed in greater detail in the August 30, 2002, LTCH PPS final rule (67 FR 55960), LTCHs are certified as acute care hospitals that meet the criteria set forth in section 1861(e) of the Act to participate as a hospital in the Medicare program, and in general, hospitals qualify for payment under the LTCH PPS instead of the IPPS solely because their inpatient average length of stay is greater than 25 days in accordance with section 1886(d)(1)(B)(iv)(I) of the Act, implemented in § 412.23(e). In the June 6, 2003, LTCH PPS final rule (68 FR 34144), we explained that prior to qualifying as a LTCH under § 412.23(e)(2)(i), hospitals generally are paid as acute care hospitals under the IPPS during the period in which they demonstrate that they have an average Medicare inpatient length of stay of greater than 25 days.

The primary reason that we did not update the LTCH PPS labor-related share for the 2004 LTCH PPS rate year was due to the same reason that we explained for not updating the labor-related share under the IPPS for FY 2004 in the August 1, 2003, IPPS (68 FR 27226) which are equally applicable to the LTCH PPS. We did not revise the labor-related share under the IPPS based on the revised and rebased FY 1997 hospital market basket and the excluded hospital market basket because of data and methodological concerns. We indicated that we would conduct further analysis to determine the most appropriate methodology and data for determining the labor-related share. Section 403 of the Medicare Prescription Drug and Modernization Act of 2003 (enacted December 8, 2003, Pub. L. 108–173) amends section 1886(d) of the Act to provide that for discharges occurring on or after October 1, 2004, the labor-related share under the IPPS is reduced to 62 percent if such a change would result in higher total payments to the hospital. While the statute provides the option to hospitals of using an alternative to the current IPPS labor-related share (71 percent), the statute does not address updating the current IPPS labor-related share. We intend to discuss the details of implementing this provision in the IPPS proposed rule for FY 2005.

Although section 403 of Pub. L. 108–173 provides for an alternative labor share percentage, this alternative only applies to hospitals paid under the IPPS and not to LTCHs. Consequently, since we have not yet implemented a change in the labor-share methodology used under the IPPS, and the alternative provided at section 403 does not apply to LTCHs, we are not proposing to change the LTCH PPS labor-share at this time.

Accordingly, we are not proposing to update the labor-related share for the 2005 LTCH PPS rate year; it would remain at 72.885 percent. As is the case under the IPPS, once our research on the labor-related share is complete, any future revisions to the LTCH PPS labor-related share will be proposed and subject to public comment.

2. Proposed Adjustment for Cost-of-Living in Alaska and Hawaii

Under § 412.525(b), we make a cost-of-living adjustment (COLA) for LTCHs located in Alaska and Hawaii to account for the higher costs incurred in those States. For the 2005 LTCH PPS rate year, we are proposing to make a COLA to payments for LTCHs located in Alaska and Hawaii by multiplying the standard Federal payment rate by the appropriate factor listed in Table I. below. These factors are obtained from the U.S. Office of Personnel Management (OPM) and are currently used under the IPPS. In addition, in this proposed rule, we are proposing that if OPM releases revised COLA factors before March 1, 2004, we would use them for the development of payments and publish them in the LTCH PPS final rule.

TABLE I.—PROPOSED COST-OF-LIVING ADJUSTMENT FACTORS FOR ALASKA AND HAWAII HOSPITALS FOR THE 2005 LTCH PPS RATE YEAR

Alaska: All areas	1.25
Hawaii:	
Honolulu County	1.25
Hawaii County	1.165
Kauai County	1.2325
Maui County	1.2375
Kalawao County	1.2375

3. Proposed Adjustment for High-Cost Outliers

a. Background

Under § 412.525(a), we make an adjustment for additional payments for outlier cases that have extraordinarily high costs relative to the costs of most discharges. Providing additional payments for outliers strongly improves the accuracy of the LTCH PPS in determining resource costs at the patient and hospital level. These additional payments reduce the financial losses that would otherwise be caused by treating patients who require more costly care and, therefore, reduce the incentives to underserve these patients. We set the outlier threshold before the beginning of the applicable rate year so that total outlier payments are projected to equal 8 percent of total payments under the LTCH PPS. Outlier payments under the LTCH PPS are determined consistent with the IPPS outlier policy.

Under section 412.525(a), we make outlier payments for any discharges if the estimated cost of a case exceeds the adjusted LTCH PPS payment for the LTC–DRG plus a fixed-loss amount. The fixed-loss amount is the amount used to limit the loss that a hospital will incur under an outlier policy. This results in Medicare and the LTCH sharing financial risk in the treatment of extraordinarily costly cases. The LTCH's loss is limited to the fixed-loss amount and the percentage of costs above the marginal cost factor. We calculate the estimated cost of a case by multiplying the overall hospital cost-to-charge ratio by the Medicare allowable covered charge. In accordance with section 412.525(a), we pay outlier cases 80 percent of the difference between the estimated cost of the patient case and the outlier threshold (the sum of the adjusted Federal prospective payment for the LTC–DRG and the fixed-loss amount).

We determine a fixed-loss amount, that is, the maximum loss that a LTCH can incur under the LTCH PPS for a case with unusually high costs before the LTCH will receive any additional payments. We calculate the fixed-loss amount by simulating aggregate payments with and without an outlier policy. The fixed-loss amount would result in estimated total outlier payments being projected to be equal to 8 percent of projected total LTCH PPS payments.

Currently, under both the LTCH PPS and the IPPS, only a maximum cost-to-charge ratio threshold (ceiling) is applied to a hospital's cost-to-charge ratio and, as discussed in the June 9, 2003, high-cost outlier final rule (68 FR 34506–34507) for discharges occurring on or after August 8, 2003, a minimum cost-to-charge ratio threshold (floor) is no longer applicable. Thus, if a LTCH's cost-to-charge ratio is above the ceiling, the applicable statewide average cost-to-charge ratio is assigned to the LTCH. In addition, for LTCHs for which we are unable to compute a cost-to-charge ratio, we also assign the applicable statewide average cost-to-charge ratio. Currently, MedPAR claims data and cost-to-charge ratios based on the latest available cost report data from Hospital Cost Report Information System (HCRIS) and corresponding MedPAR claims data are used to establish a fixed-loss threshold amount under the LTCH PPS.

In the June 9, 2003, high-cost outlier final rule (68 FR 34507), consistent with the outlier policy changes for acute care hospitals under the IPPS discussed in that same final rule, we no longer assign the applicable statewide average cost-to-charge ratio when a LTCH's cost-to-charge ratio falls below the minimum cost-to-charge ratio threshold (floor). We made this policy change because, as is the case for acute care hospitals, we believe LTCHs could arbitrarily increase their charges in order to maximize outlier payments. Even though this arbitrary increase in charges should result in a lower cost-to-charge ratio in the future (due to the lag time in cost report settlement), previously when a LTCH's actual cost-to-charge ratio fell below the floor, the LTCH's cost-to-charge ratio was raised to the applicable statewide average cost-to-charge ratio. This application of the statewide average resulted in inappropriately higher outlier payments. Accordingly, for LTCH PPS discharges occurring on or after August 8, 2003, in making outlier payments under § 412.525 (and short-stay outlier payments under § 412.529), we apply the LTCH's actual cost-to-charge ratio to determine the cost of the case, even where the LTCH's actual cost-to-charge ratio falls below the floor.

Also, in the June 9, 2003, high-cost outlier final rule (68 FR 34507), consistent with the policy change for acute care hospitals under the IPPS, under § 412.525(a)(4), by cross-referencing § 412.84(i), we established that we will continue to apply the applicable statewide average cost-to-charge ratio when a LTCH's cost-to-charge ratio exceeds the maximum cost-to-charge ratio threshold (ceiling) by adopting the policy at § 412.84(i)(3)(ii). As we explained in that same final rule, cost-to-charge ratios above this range are probably due to faulty data reporting or entry. Therefore, these cost-to-charge ratios should not be used to identify and make payments for outlier cases because such data are clearly errors and should not be relied upon. In addition, we made a similar change to the short-stay outlier policy at § 412.529. Since cost-to-charge ratios are also used in determining short-stay outlier payments, the rationale for that change mirrors that for high-cost outliers.

b. Establishment of the Proposed Fixed-Loss Amount

In the June 6, 2003, final rule (68 FR 34144), for the 2004 LTCH PPS rate year, we used the March 2002 update of the FY 2001 MedPAR claims data to determine a fixed-loss threshold that would result in outlier payments projected to be equal to 8 percent of total payments, based on the policies described in that final rule, because these data were the best data available. We calculated cost-to-charge ratios for determining the fixed-loss amount based on the latest available cost report data in HCRIS and corresponding MedPAR claims data from FYs 1998, 1999, and 2000.

In that same final rule, in determining the fixed-loss amount for the 2004 LTCH PPS rate year (using the outlier policy under § 412.525(a) in effect on July 1, 2003), we used the current combined operating and capital cost-to-charge ratio floor and ceiling under the IPPS of 0.206 and 1.421, respectively (as explained in the IPPS final rule (67 FR 50125, August 1, 2002)). As we discussed in the June 9, 2003, high-cost outlier final rule (68 FR 34508), we concluded that it was not necessary to recalculate a new fixed-loss amount once the changes to the outlier policy discussed in that final rule became effective because the difference between the fixed-loss amount determined with or without the application of the floor would be negligible.

If a LTCH's cost-to-charge ratio was below this floor or above this ceiling, we assigned the applicable IPPS statewide average cost-to-charge ratio. We also assigned the applicable statewide average for LTCHs for which we are unable to compute a cost-to-charge ratio, such as for new LTCHs. Therefore, based on the methodology and data described above, in the June 6, 2003, final rule (68 FR 34144), for the 2004 LTCH PPS rate year, we established a fixed-loss amount of $19,590. Thus, during the 2004 LTCH PPS rate year, we pay an outlier case 80 percent of the difference between the estimated cost of the case and the outlier threshold (the sum of the adjusted Federal LTCH payment for the LTC–DRG and the fixed-loss amount of $19,590).

Also, in the June 6, 2003, final rule (68 FR 34145), we established that beginning with the 2004 LTCH PPS rate year, we will calculate a single fixed-loss amount for each LTCH PPS rate year based on the version of the GROUPER that is in effect as of the beginning of the LTCH PPS rate year (that is, July 1, 2003, for the 2004 LTCH PPS rate year). Therefore, for the 2004 LTCH PPS rate year, we established a single fixed-loss amount based on the Version 20.0 of the GROUPER, which was in effect at the start of the 2004 LTCH PPS rate year (July 1, 2003). As we noted above, the fixed-loss amount for the 2004 LTCH PPS rate year is $19,590.

In calculating the proposed fixed-loss amount for the 2005 LTCH PPS rate year, we applied the current outlier policy under § 412.525(a); that is, we assigned the applicable statewide average cost-to-charge ratio only to

LTCHs whose cost-to-charge ratios exceeded the ceiling (and not when they fell below the floor). Accordingly, we used the current IPPS combined operating and capital cost-to-charge ratio ceiling of 1.366 (as explained in the IPPS final rule (68 FR 45478, August 1, 2003)). We believed that using the current combined IPPS operating and capital cost-to-charge ratio ceiling for LTCHs is appropriate for the same reasons we stated above regarding the use of the current combined operating and capital cost-to-charge ratio ceiling under the IPPS.

In this proposed rule, for the 2005 LTCH PPS rate year, we used the December 2002 update of the FY 2002 MedPAR claims data to determine a proposed fixed-loss amount that would result in outlier payments projected to be equal to 8 percent of total payments, based on the policies described in this proposed rule, because these data are the best LTCH data available. We considered using claims data from the September 2003 update of the FY 2003 MedPAR to determine the proposed fixed-loss amount (and the budget neutrality offset discussed below in section IV.C.6.) for the 2005 LTCH PPS rate year. However, initial analysis has shown that the FY 2003 MedPAR data contain coding errors. As in the case with the FY 2002 MedPAR, we have learned that a large hospital chain of LTCHs has continued to consistently code diagnoses inaccurately on the claims it submitted, and these coding errors are reflected in the FY 2003 MedPAR data. The coding inaccuracies in the MedPAR claims data can cause significant skewing of the fixed-loss amount and would impact the determination of the budget neutrality offset. While we have corrected the coding inaccuracies in the FY 2002 MedPAR, we were unable to correct the coding errors in the FY 2003 MedPAR in time for publication of this proposed rule since the correction process requires extensive programming work. Accordingly, we are using the December 2002 update of the FY 2002 MedPAR claims data to determine a proposed fixed-loss amount for the 2005 LTCH PPS rate year for this proposed rule. We expect to be able to use the corrected FY 2003 MedPAR to calculate a revised fixed-loss amount for the final rule. Furthermore, as noted above, we determined the proposed fixed-loss amount based on the version of the GROUPER that would be in effect as of the beginning of the 2005 LTCH PPS rate year (July 1, 2004), that is, Version 21.0 of the LTCH PPS GROUPER (68 FR 45374–45385). We also computed cost-to-charge ratios for determining the proposed fixed-loss amount for the 2005 LTCH PPS rate year based on the latest available cost report data in HCRIS and corresponding MedPAR claims data from FYs 1999, 2000, and 2001. As we explained above, the current applicable IPPS statewide average cost-to-charge ratios were applied when a LTCH's cost-to-charge ratio exceeded the ceiling (1.366). In addition, we assigned the applicable statewide average to LTCHs for which we were unable to compute a cost-to-charge ratio. (Currently, the applicable IPPS statewide averages can be found in Tables 8A and 8B of the August 1, 2003, IPPS final rule (68 FR 45637–45638).)

Accordingly, based on the data and policies described above, we are proposing a fixed-loss amount of $21,864 for the 2005 LTCH PPS rate year. Thus, we would pay an outlier case 80 percent of the difference between the estimated cost of the case and the proposed outlier threshold (the sum of the adjusted proposed Federal LTCH payment for the LTC–DRG and the proposed fixed-loss amount of $21,864).

c. Reconciliation of Outlier Payments Upon Cost Report Settlement

In the June 9, 2003, high-cost outlier final rule (68 FR 34508–34512), we made changes to the LTCH outlier policy consistent with those made for acute care hospitals under the IPPS because, as we discussed in that same final rule, we became aware that payment vulnerabilities existed in the previous IPPS outlier policy. Because the LTCH PPS high-cost outlier and short-stay policies are modeled after the outlier policy in the IPPS, we believe they were susceptible to the same payment vulnerabilities and, therefore, also merited revision. Consistent with the change made for acute care hospitals under the IPPS at § 412.84(m), we established under § 412.525(a)(4)(ii), by cross-referencing § 412.84(m), that effective for LTCH PPS discharges occurring on or after August 8, 2003, any reconciliation of outlier payments may be made upon cost report settlement to account for differences between the actual cost-to-charge ratio and the estimated cost-to-charge ratio for the period during which the discharge occurs. As is the case with the changes made to the outlier policy for acute care hospitals under the IPPS, the instructions for implementing these regulations are discussed in further detail in Program Memorandum Transmittal A–03–058. In addition, in that same final rule (68 FR 34513), we established a similar change to the short-stay outlier policy at § 412.529(c)(5)(ii).

We also discussed in the June 9, 2003, IPPS high-cost outlier final rule (68 FR 34507–34512) that only using cost-to-charge ratios based on the latest settled cost report does not reflect any dramatic increases in charges during the payment year when making outlier payments. Because a LTCH has the ability to increase its outlier payments through a dramatic increase in charges and because of the lag time in the data used to calculate cost-to-charge ratios, in that same final rule (68 FR 34494–34515), consistent with the policy change for acute care hospitals under the IPPS at § 412.84(i)(2), we established that, for LTCH PPS discharges occurring on or after October 1, 2003, fiscal intermediaries will use more recent data when determining a LTCH's cost-to-charge ratio. Therefore, by cross-referencing § 412.84(i)(2) under § 412.525(a)(4)(iii), we established that fiscal intermediaries will use either the most recent settled cost report or the most recent tentative settled cost report, whichever is from the later period. In addition, in that same final rule, we established a similar change to the short-stay outlier policy at § 412.529(c)(5)(iii).

d. Application of Outlier Policy to Short-Stay Outlier Cases

As we discussed in the August 30, 2002, final rule (67 FR 56026), under some rare circumstances, a LTCH discharge could qualify as a short-stay outlier case (as defined under § 412.529 and discussed in section IV.B.4.b. of this preamble) and also as a high-cost outlier case. In such a scenario, a patient could be hospitalized for less than five-sixths of the geometric average length of stay for the specific LTC–DRG, and yet incur extraordinarily high treatment costs. If the costs exceeded the outlier threshold (that is, the short-stay outlier payment plus the fixed-loss amount), the discharge would be eligible for payment as a high-cost outlier. Thus, for a short-stay outlier case in the 2005 LTCH PPS rate year, the high-cost outlier payment would be 80 percent of the difference between the estimated cost of the case and the outlier threshold (the sum of the proposed fixed-loss amount of $21,864 and the amount paid under the short-stay outlier policy).

4. Proposed Adjustments for Special Cases

a. General

As discussed in the August 30, 2002, final rule (67 FR 55995), under section 123 of Pub. L. 106–113, the Secretary generally has broad authority in developing the PPS for LTCHs, including whether (and how) to provide for adjustments to reflect variations in the necessary costs of treatment among LTCHs.

Generally, LTCHs, as described in section 1886(d)(1)(B)(iv) of the Act, are distinguished from other inpatient hospital settings by maintaining an average inpatient length of stay of greater than 25 days. However, LTCHs may have cases that have stays of considerably less than the average length of stay and that receive significantly less than the full course of treatment for a specific LTC–DRG. As we explained in the August 30, 2002, final rule (67 FR 55995), such cases would be paid inappropriately if the hospital were to receive the full LTC–DRG payment. Below we discuss the payment methodology for these special cases as implemented in the August 30, 2002, final rule (67 FR 55955–56010).

b. Proposed Adjustment for Short-Stay Outlier Cases

A short-stay outlier case may occur when a beneficiary receives less than the full course of treatment at the LTCH. before being discharged. These patients may be discharged to another site of care or they may be discharged and not readmitted because they no longer require treatment. Furthermore, patients may expire early in their LTCH stay.

As noted above, generally LTCHs are defined by statute as having an average inpatient length of stay of greater than 25 days. We believe that a payment adjustment for short-stay outlier cases results in more appropriate payments, because these cases most likely would not receive a full course of treatment in such a short period of time and a full LTC–DRG payment may not always be appropriate. Payment-to-cost ratios simulated for LTCHs, for the cases described above, show that if LTCHs receive a full LTC–DRG payment for those cases, they would be significantly "overpaid" for the resources they have actually expended.

Under § 412.529, in general, we adjust the per discharge payment to the least of 120 percent of the cost of the case, 120 percent of the LTC–DRG specific *per diem* amount multiplied by the length of stay of that discharge, or the full LTC–DRG payment, for all cases with a length of stay up to and including five-sixths of the geometric average length of stay of the LTC–DRG.

As we noted in section IV.C.3. of this preamble, in the June 9, 2003, high-cost outlier final rule (68 FR 34494–34515), we revised the methodology for determining cost-to-charge ratios for acute care hospitals under the IPPS because we became aware that payment vulnerabilities existed in the previous IPPS outlier policy. As we also explained in that same final rule, because the LTCH PPS high-cost outlier and short-stay outlier policies are modeled after the outlier policy in the IPPS, we believe they were susceptible to the same payment vulnerabilities and, therefore, merited revision. Consistent with the policy established for acute care hospitals under the IPPS at § 412.84(i) and (m) in the June 9, 2003, high-cost outlier final rule (68 FR 34515), and similar to the policy change described above for LTCH PPS high-cost outlier payments at § 412.525(a)(4)(ii), we established under § 412.529(c)(5)(ii) that for discharges on or after August 8, 2003, short-stay outlier payments are subject to the provisions in the regulations at § 412.84(i)(1), (i)(3) and (i)(4), and (m). In addition, short-stay outlier payments are subject to the provisions in the regulations at § 412.84(i)(2) for discharges on or after October 1, 2003, in accordance with § 412.529(c)(5)(iii). Therefore, in the June 9, 2003, high-cost outlier final rule (68 FR 34548–34513), under § 412.529(c)(5)(ii), by cross-referencing proposed § 412.84(i)(2), we established that fiscal intermediaries will use either the most recent settled cost report or the most recent tentative settled cost report, whichever is from the later period, in determining a LTCH's cost-to-charge ratio.

In addition, by cross-referencing § 412.84(i), we established that the applicable statewide average cost-to-charge ratio is only applied when a LTCH's cost-to-charge ratio exceeds the ceiling. Thus, the applicable statewide average cost-to-charge ratio is no longer applied when a LTCH's cost-to-charge ratio falls below the floor. Furthermore, by cross-referencing § 412.84(i)(4), we established that any reconciliation of payments for short-stay outliers may be made upon cost report settlement to account for differences between the estimated cost-to-charge ratio and the actual cost-to-charge ratio for the period during which the discharge occurs. As noted above, in the discussion of the high-cost outlier policy in section IV.C.3. of this preamble, the instructions for implementing these regulations are discussed in further detail in Program Memorandum Transmittal A–03–058. In the June 6, 2003, final rule (68 FR 34146–34148), for certain hospitals that qualify as LTCHs under section 1886(d)(1)(B)(iv)(II) of the Act ("subclause (II)" LTCHs) as added by section 4417(b) of Pub. L. 105–33, and implemented in § 412.23(e)(2)(ii), we established a temporary adjustment to the short-stay outlier policy during the 5-year transition period. Under § 412.529(c)(4), effective for discharges from a "subclause (II)" LTCH occurring on or after July 1, 2003, the short-stay outlier percentage is 195 percent during the first year of the hospital's 5-year transition. For the second cost reporting period, the short-stay outlier percentage is 193 percent; for the third cost reporting period, the percentage is 165 percent; for the fourth cost reporting period, the percentage is 136 percent; and for the final cost reporting period of the 5-year transition (and future cost reporting periods), the short-stay outlier percentage is 120 percent, that is, the same as it is for all other LTCHs under the LTCH PPS.

As we discussed in the June 6, 2003, final rule (68 FR 34147), we established this formula with the expectation that an adjustment to short-stay outlier payments during the transition will result in reducing the difference between payments and costs for a "subclause (II)" LTCH for the period of July 1, 2003, through the end of the transition period, when the LTCH PPS will be fully phased-in.

As we stated in that same final rule, we also expect that during this 5-year period, "subclause (II)" LTCHs will make every attempt to adopt the type of efficiency enhancing policies that generally result from the implementation of prospective payment systems in other health care settings. We are not proposing any changes to the short-stay outlier policy in this proposed rule.

c. Proposed Extension of the Interrupted Stay Policy

At existing § 412.531(a), we define an "interruption of a stay" as a stay at a LTCH during which a Medicare inpatient is transferred upon discharge to an acute care hospital, an IRF, or a SNF for treatment or services that are not available in the LTCH and returns to the same LTCH within applicable fixed-day periods. (We also include transfers to swing beds under this interrupted stay policy for LTCH payment policy determinations, consistent with the SNF PPS payment policy. That is, a readmission to a LTCH from post-hospital SNF care being provided in a swing bed that is located either in the LTCH itself or in another onsite Medicare provider has the same policy consequence as a readmission to the LTCH from an onsite SNF (June 6, 2003, 68 FR 34149).)

As defined above, an interrupted stay is treated as one discharge from the

LTCH. The day-count of the applicable fixed-day period of an interrupted stay begins on the day of discharge from the LTCH (which is also the day of admission to the other site of care). For a discharge to an acute care hospital, the applicable fixed-day period is 9 days, for an IRF, 27 days, and for a SNF 45 days. The counting of the days begins on the day of discharge from the LTCH and ends on the 9th, 27th, or 45th day for an acute care hospital, an IRF, or a SNF, respectively, after the discharge.

If the patient is readmitted to the LTCH within the fixed-day threshold, return to the LTCH is considered part of the first admission and only a single LTCH PPS payment will be made. For example, if a LTCH patient is discharged to an acute hospital and is readmitted to the LTCH on any day up to and including the 9th day following the original day of discharge from the LTCH, one LTC–DRG payment will be made. If the patient is readmitted to the LTCH from the acute care hospital on the 10th day after the original discharge or later, Medicare will pay for the second admission as a separate stay with an additional LTC–DRG assignment. In implementing this policy, we provide that, in the event a Medicare inpatient is discharged from a LTCH and is readmitted and the stay qualifies as an interrupted stay, the provider should cancel the claim generated by the original stay in the LTCH and submit one claim for the entire stay. (For further details, see Medicare Program Memorandum Transmittal A–02–093, September 2002.)

On the other hand, if the patient stay exceeds the total fixed-day threshold outside of the LTCH at another facility before being readmitted, two separate payments would be made. One would be based on the principal diagnosis and length of stay for the first admission and the other based on the principal diagnosis and length of stay for the second admission. Depending upon their lengths of stay, both stays could result in payments as a short-stay outlier (§ 412.529), a full LTC–DRG, or even a high-cost outlier. Further, if the principal diagnosis is the same for both admissions, the hospital could receive two similar payments.

When we introduced the interrupted stay policy for LTCHs in the August 30, 2002, final rule (67 FR 56002–56006), we noted that we would consider expanding or revising the policy based on information received from the provider community or information gained from our ongoing monitoring activities. During the first year of the LTCH PPS, it has come to our attention, from both of these sources, that certain LTCHs are discharging patients during the course of their treatment for the sole purpose of receiving specific tests or procedures from another facility (that should have been furnished under arrangements by the LTCHs), and then readmitting the patient to the LTCH following the administration of the test or procedure. In other words, these patients do not stop receiving medical care that should be considered LTCH inpatient services during the period between their discharge from and readmission to the LTCH. On the contrary, they continue to receive care, often of a highly specialized type, from the other facility before being readmitted for further inpatient care at the LTCH. This sequence of care suggests that the original discharge from the LTCH may be motivated by financial considerations rather than by clinical judgment and, therefore, would be inappropriate.

Existing regulations at § 412.509(c) require a LTCH to furnish all necessary covered services for a Medicare beneficiary who is an inpatient of the hospital either directly or under arrangements (as defined in § 409.3). Under § 409.3, when services are furnished under arrangements, Medicare payments made to the provider that arranged for the services discharges the liability of the beneficiary or any other person to pay for those services. The "under arrangements" policy set forth in § 412.509 for LTCHs derives from the regulations at § 411.15(m), which implement section 1862(a)(14) of the Act. Section 1862(a) of the Act specifies the services for which no payment may be made under Medicare Part A and Part B. Section 1862(a)(14) of the Act specifies the exception for certain services to be furnished "under arrangements" by providers.

If a LTCH obtains, from another facility "under arrangements," a specific test or procedure for one of its inpatients that is not available on the LTCH's premises, as contemplated by § 412.509, a discharge and a subsequent readmission would be unnecessary and inappropriate. This is true even if it is necessary to transport the patient to another facility to receive the arranged-for service. Furthermore, no additional claim should be submitted to Medicare by the other entity that actually furnished the test or procedure because, under § 412.509(c), the LTCH must furnish all necessary covered services to the Medicare beneficiary who is an inpatient of the hospital either directly or under arrangements. In such a situation, generally, the LTCH would include the medically necessary test or procedure on its patient claim to Medicare (which could have an effect on the assignment of the LTC–DRG and thus the Medicare payment to the LTCH) and the LTCH would be responsible for paying the provider directly for the test or procedure.

Patient discharges from the LTCH for tests or procedures that should have been provided under arrangements, followed by LTCH readmission, result in an inappropriate increase in Medicare costs in three ways:

First, the Medicare payment associated with the LTC–DRG that would be assigned to the patient's stay will typically already include the costs of the test or procedure. (The August 30, 2002, LTCH PPS final rule (67 FR 55977–55985), includes an in-depth description of the derivation of LTC–DRGs from ICD–9–CM codes on Medicare claims and a discussion of the development and calculation of LTC–DRG relative weights.) Second, the intervening provider will bill Medicare separately for the test or procedure. Thus, if services that should have been furnished directly or under arrangements by the LTCH are instead unbundled and billed separately, Medicare would pay the other provider for the service that should have been paid for "under arrangements" by the LTCH under § 412.509.

Third, a discharge for outpatient services and a subsequent readmission to the LTCH is not currently covered under the interrupted stay policy at existing § 412.531. Section 412.531(a) only includes discharges from a LTCH to an acute care hospital, an IRF, and a SNF for treatment or services not available in the LTCH and subsequent readmission to the same LTCH. If a patient is discharged and readmitted to the LTCH following an outpatient test or procedure, under current policy, after making a LTCH PPS payment for the first discharge, there would be a second Medicare payment to the LTCH when the patient is finally discharged.

In order to address these concerns, we are proposing to revise the definition of an interruption of a stay under § 412.531 to add situations in which a patient is discharged from the LTCH and readmitted to the same LTCH within 3 days of the discharge (proposed revised § 412.531(a)(1)). We believe that if a patient is discharged from a LTCH for any reason and is then readmitted within 3 days, in general, the patient's original admitting diagnoses would not change significantly during those 3 days. Therefore, such a readmission would not constitute a new episode of care. We question whether a patient who was discharged and then returned to the same LTCH within 3 days should have been discharged in the first place. Since LTCHs are designed to treat patients with a high level of acuity and multicomorbidities, we believe that a 3-day period is a reasonable window during which necessary offsite medical care might be delivered, under arrangements, as contemplated under § 412.509, without an appreciable change in the original admitting diagnoses. Moreover, this 3-day period is consistent with the interrupted stay policy under the IRF PPS under which the maximum period of time that a patient could be away from the IRF is 3 days before a new patient assessment is required. Therefore, under our proposal, if a patient were discharged on Monday, and readmitted either on that Monday (the first day), Tuesday (the second day), or Wednesday (the third day), the subsequent readmission would not be considered a new admission and Medicare would pay the LTCH for only one discharge based on the combined length of stay for the period prior to and after the absence from the LTCH.

We are further proposing that, under the proposed revision of the interruption of stay policy for LTCHs, any treatment or medical services furnished to the individual during the 3-day (or less) absence from the LTCH could not be billed separately to the Medicare program or to the beneficiary, but would be paid as "under arrangements" services to the LTCH. We calculate payments under the LTCH PPS using base year costs that include the numerous tests and procedures typical of the complicated medical conditions that characterize LTCH patients, including those furnished by other providers. Therefore, we believe that a readmission to the LTCH that triggers the proposed 3-day interrupted stay policy should be treated as a continuation of the episode of care that occasioned the first admission. Further, we believe that the readmission to the LTCH within 3 days establishes the presumption that any treatment or services furnished during the intervening 3 (or less) days should have been provided by the LTCH "either directly or under arrangements" (§ 412.509(b)). The entire stay would generate one LTC–DRG payment under the LTCH PPS, which would be "payment in full for all inpatient hospital services, as defined in § 409.10." (§ 412.509(a)) Under § 409.10(a) inpatient hospital services means the following services furnished to an inpatient of a qualified hospital: (1) Bed and board; (2) nursing services and other related services; (3) use of hospital or CAH facilities; (4) medical social services; (5) drugs, biologicals, supplies, appliances, and equipment; (6) certain other diagnostic or therapeutic services; (7) medical or surgical services provided by certain interns or residents-in-training; and (8) transportation services, including transport by ambulance.

As explained above, we are proposing that a readmittance to the LTCH within 3 days after a discharge will result in one LTC–DRG payment for the entire stay. Since we are treating both parts of the stay as one episode of care, we are proposing that treatment or care provided during the "interruption" be considered to have occurred during that episode of care and that payment for such services are included in the LTC–DRG payment. We are also proposing to include the days of the 3-day interruption of stay in counting LTCH days to determine the total length of stay of the patient at the LTCH if medical treatment or care were provided during the 3 days because these services will be considered to have been paid for as part of the total LTCH stay (proposed § 412.531(b)(1)(iii)). We are further proposing that if a patient is discharged home, and within a 3-day period received no additional medical treatment or service, but is readmitted to the LTCH, the days away from the LTCH would not be included in the length of stay calculation. This is presently the day count methodology that we use in the existing interrupted stay policy at § 412.531(b)(1) as applied to acute care hospitals, IRFs, and SNFs.

We are proposing that this policy be applicable to all services or procedures provided to the patient either under Medicare Part A, or Part B, except for the services which are expressly excluded from bundling under section 1886(a)(1)(H)(i) of the Act and § 411.15(m), such as services furnished by physicians under § 415.102(a) and other specific health professionals. Failure to comply with this bundling requirement could lead to sanctions such as termination of the LTCH's Medicare provider agreement or civil money penalties (under section 1866(a)(1)(H)(i) of the Act).

Although we understand that, in good faith, a patient could be discharged from a LTCH, return home for a day or two, experience a setback, and then be readmitted to the LTCH, we believe that such a readmission to the LTCH should be considered an extension of the original hospitalization and that Medicare should not pay for two claims for what was, in effect, one episode of care. The proposed 3-day interrupted stay policy takes into account the profile of most LTCH patients, as typically very sick individuals with multicomorbidities. We believe that it is reasonable to presume that, should this type of patient be discharged and then readmitted to a LTCH with 3 days the readmission signifies a continuation of the original hospital stay and not a new episode of care. Furthermore, we are concerned about reports of LTCHs discharging and readmitting patients who are still undergoing active treatment rather than obtaining services for these patients "under arrangements" in accordance with section 1862(a)(14) of the Act and the regulations at § 412.509.

If the policy is finalized, we intend to collect data on any Medicare claims for outpatient services as well as inpatient services furnished during the time that the patients are away from the LTCH under the proposed 3-day interrupted stay policy. We would review data to determine whether we should expand the 3-day time period and we will consider proposing such a change in a future rule. Further, if it appears that additional patients are being discharged for the purpose of receiving tests or procedures at other Medicare settings, and then readmitted to the LTCH, in order for the LTCH to avoid paying for the procedure "under arrangements," we may find it appropriate for our Quality Improvement Organizations (QIO) to evaluate the medical basis for the original discharge. A patient discharge that is not clinically justifiable could constitute potential violation of the LTCH's conditions of participation in the Medicare program for inadequate discharge planning or an inappropriate discharge from the LTCH under § 482.43. Moreover, as noted above, if a separate bill is submitted by an entity other than the LTCH for services furnished during this period, this could also be a violation of the LTCH's provider agreement obligation regarding bundled services.

In proposing this policy, we are not attempting to restrict a LTCH from pursuing necessary or more appropriate clinical care from another facility. As we designed the PPS for LTCHs, the original interrupted stay policy was created for situations where sound clinical judgment could suggest a different treatment setting for LTCH patients: a patient requiring emergency surgery at an acute care hospital; a patient who would appear to benefit from a specific therapy regimen at an IRF; or a patient who had improved and, therefore, could be appropriately cared for at a SNF. The policy accounted for a readmission to the LTCH after the emergency care or in the event of a change in the patient's condition, that is, for sound clinical reasons. Fundamentally, the interrupted stay policy resulted from our determination to allow considerable latitude to medical personnel in this regard without untoward payment consequences for the Medicare program.

We are proposing a revision to the existing interrupted stay policy because we believe that 3 days in most instances represents an appropriate interval for establishing whether or not the reason for the patient's readmission is directly connected to the original episode of care and whether or not Medicare-covered services were obtained during the interruption that should have otherwise been provided "under arrangements" by the LTCH.

All inpatient services, under Medicare, fall within the purview of the requirement of section 1862(a)(14) of the Act, and, therefore, what we have proposed is not a departure from existing policy. Under section 1862(a)(14) of the Act, notwithstanding any other provision of this title, "no payment may be made under Part A or Part B for any expenses incurred for items or services which are other than physicians' services (as defined in regulations promulgated specifically for purposes of this paragraph), services described by section 1861(s)(2)(K) of the Act (certified nurse-midwife services, qualified psychologist services, and services of a certified registered nurse anesthetist) and which are furnished to an individual who is a patient of a hospital or critical access hospital by an entity other than the hospital or critical access hospital unless the services are furnished under arrangements (as defined in section 1861(w)(1) of the Act with the entity made by the hospital or critical access hospital." Section 1861(w)(1) of the Act states that "[t]he term 'arrangements' is limited to arrangements under which receipt of payment by the hospital, critical access hospital, skilled nursing facility, home health agency, or hospice program (whether in its own right or as agent), with respect to services for which an individual is entitled to have payment made under this title, discharges the liability of such individual or any other person to pay for the services." We believe the objective of these statutory provisions, which were implemented for inpatient acute care hospitals in regulations at § 411.15(m) and subsequently at § 412.509 for LTCHs, was to discharge financial liability for inpatients who may have received additional care off-premises and to assign payment responsibility for such care to the hospital that is being paid for that beneficiary's total care for that spell of illness. The total care delivered by the hospital may be provided "directly" or "under arrangements" with other facilities (§ 412.509(c)) and was included in Medicare's payment to the hospital. Over the years, we have often referred to this as the "prohibition against unbundling" for purposes of emphasizing that if a Medicare provider "unbundles" specific components of a beneficiary's total inpatient care (provided either "directly" or "under arrangements") and sends separate claims to Medicare for those tests or treatments, the provider would be acting in violation of the statute and applicable regulations. Since LTCHs treat patients with multicomorbidities who are often in need of a wide range of diagnostic and treatment modalities and lengthy hospitalizations, we believe that in this particular setting, this statutory requirement is particularly vulnerable to gaming. For that reason, we are taking this opportunity to clarify the existing general unbundling prohibition and to propose specific language on the unbundling prohibition as it applies to the interrupted stay policy under the LTCH PPS and are proposing to codify it in regulations. As noted above, we are concerned that LTCH patients, under active treatment, are being inappropriately discharged to other treatment sites, receiving tests or procedures related to one of the diagnoses for which the patient is being hospitalized and which otherwise should have been provided at the LTCH either directly or under arrangements under § 412.509 and then readmitted to the LTCH. Another claim is also being submitted to Medicare by the other treatment site for those tests or procedures. As stated earlier, under the LTCH PPS, payments associated with specific LTC–DRGs include all costs associated with rendering care to the type of patients treated in LTCHs and, therefore, additional Medicare payments for such services would be inappropriate.

We understand that during a particular hospitalization, a typical LTCH patient, with multicomorbidities, could suddenly require emergency care at an acute care hospital. This would be the case, for example, if a patient who was admitted to the LTCH with a principal diagnosis of chronic obstructive pulmonary disease and respirator dependence, with secondary diagnoses of hypertension, Type II diabetes mellitus, history of coronary artery disease, and history of bladder cancer suddenly exhibits symptoms consistent with a pneumothorax (lung collapse) and requires treatment that is beyond the scope of the LTCH. Services obtained at an acute care hospital, under the proposed policy would be considered related to the original diagnoses and submission of a separate claim by the acute hospital should be considered a violation of the unbundling requirement established by section 1862(a)(14) of the Act. Payment to the acute hospital for any services delivered would be the responsibility of the LTCH since the critical episode was directly related to the hospitalization at the LTCH. Conversely, if the same patient had instead suddenly suffered a myocardial infarction (heart attack) that requires a cardiac workup, evaluation, and possible implantation of a cardiac stent, it may be appropriate to discharge this patient for admission to an acute care facility for appropriate evaluation and the invasive cardiac procedure. Under these circumstances, the admission to the acute hospital was totally unrelated to the patient's diagnoses in the LTCH and arguably there may be no need to bundle the services. A discharge from the LTCH and a readmission following the procedure at the acute hospital in order to resume the treatment provided by the LTCH, for which the patient was originally hospitalized, could be entirely appropriate. (Notwithstanding the necessity of the discharge, under the proposed 3-day interrupted stay policy, there would be no additional LTC–DRG payment generated to the LTCH if the patient returns to the LTCH within the 3-day period.) It could be argued that in this type of a subsequent admission to the acute hospital, the acute care hospital should be able to submit a claim to Medicare for the procedure. (This payment to the acute hospital may be subject to the postacute care policy at § 412.4, depending upon the DRG to which it is assigned (68 FR 45404 and 45412, August 1, 2003).)

We are aware that there may be exceptions, and that in the example cited above, sound medical judgment could have dictated that the patient who needed the cardiac stent should first be discharged to the acute hospital and then readmitted to the LTCH within 3-days in order to continue necessary treatment at the LTCH. In such a case, notwithstanding our proposed 3-day interrupted stay policy, it is arguable that the implantation of the cardiac stent does not fall within the category of services that should be paid for by the LTCH under arrangements, and that the acute hospital should be able to submit a claim to Medicare.

Accordingly, while, arguably, it may be appropriate to attempt to limit the proposed unbundling requirement that services be provided under arrangement to those that are "related" to the admitting diagnoses of the LTCH patient, we have not been able to develop a methodology that would be administratively feasible and not subject to gaming, given the multiple comorbidities typical of LTCH patients. The prospective payment system for this particular setting was designed to capture all costs associated with treating these highly complicated cases and we believe that it will difficult to distinguish whether a particular critical episode can been seen as arising from one of the patient's many medical conditions for which the patient is presently at the LTCH. We are soliciting comments and suggestions that are consistent with the stated policy goals described above and that would be administratively feasible.

We understand that any policy that is adopted in the final regulation would need to be issued with detailed instructions to fiscal intermediaries on implementation procedures to ensure a correct and consistent interpretation of our policy objectives.

d. Onsite Discharges and Readmittances

Under § 412.532, generally, if more than 5 percent of all Medicare discharges during a cost reporting period are patients who are discharged to an onsite SNF, IRF, or psychiatric facility, or to an onsite acute care hospital and who are then directly readmitted to the LTCH, only one LTC–DRG payment will be made to the LTCH for these type of discharges and readmittances during the LTCH's cost reporting period. Therefore, payment for the entire stay will be paid either as one full LTC–DRG payment or a short-stay outlier, depending on the duration of the entire LTCH stay.

In applying the 5-percent threshold, we apply one threshold for discharges and readmittances with a co-located acute care hospital. There is also a separate 5-percent threshold for all discharges and readmittances with co-located SNFs, IRFs, and psychiatric facilities. In the case of a LTCH that is co-located with an acute care hospital, an IRF, or a SNF, the interrupted stay policy at § 412.531 applies until the 5-percent threshold is reached. However, once the applicable threshold is reached, all such discharges and readmittances to the applicable site(s) for that cost reporting period are paid as one discharge pursuant to § 412.532. This means that even if a discharged LTCH Medicare patient was readmitted to the LTCH following a stay in an acute care hospital of greater than 9 days, if the facilities share a common location and the 5-percent threshold were exceeded, the subsequent discharge from the LTCH will not represent a separate hospitalization for payment purposes. Only one LTC–DRG payment will be made for all such discharges during a cost reporting period to the acute care hospital, regardless of the length of stay at the acute care hospital, that are followed by readmittances to the onsite LTCH.

Similarly, if the LTCH has exceeded its 5-percent threshold for all discharges to an onsite IRF, SNF, or psychiatric hospital or unit, with readmittances to the LTCH, the subsequent LTCH discharge for patients from any of those sites for the entire cost reporting period will not be treated as a separate discharge for Medicare payment purposes. (As under the interrupted stay policy, payment to an acute care hospital under the IPPS, to an IRF under the IRF PPS, and to a SNF under the SNF PPS, will not be affected. Payments to the psychiatric facility also will not be affected.)

5. Other Payment Adjustments

As indicated earlier, we have broad authority under section 123 of Public Law 106–113, including whether (and how) to provide for adjustments to reflect variations in the necessary costs of treatment among LTCHs. Thus, in the August 30, 2002, final rule (67 FR 56014–56027), we discussed our extensive data analysis and rationale for not implementing an adjustment for geographic reclassification, rural location, treating a disproportionate share of low-income patients (DSH), or indirect medical education (IME) costs. In that same final rule, we stated that we would collect data and reevaluate the appropriateness of these adjustments in the future once more LTCH data become available after the LTCH PPS is implemented. Because the LTCH PPS has only been implemented for less than 2 years and the lag-time in data availability, sufficient new data have still not yet been generated that would enable us to conduct a comprehensive reevaluation of these payment adjustments. Nonetheless, we have reviewed the limited data that are available and found no evidence to support additional proposed policy changes. Therefore, in this proposed rule, we are not proposing an adjustment for geographic reclassification, rural location, DSH, or IME at this time. However, we will continue to collect and interpret new data as they become available in the future to determine if these data support proposing any additional payment adjustments.

6. Proposed Budget Neutrality Offset To Account for the Transition Methodology

Under § 412.533, we implemented a 5-year transition period from reasonable cost-based payment to prospective payment, during which a LTCH will be paid an increasing percentage of the LTCH PPS rate and a decreasing percentage of its payments under the reasonable cost-based payment methodology for each discharge. Furthermore, we allow a LTCH to elect to be paid based on 100 percent of the standard Federal rate in lieu of the blended methodology.

The standard Federal rate was determined as if all LTCHs will be paid based on 100 percent of the standard Federal rate. As stated earlier, we provide for a 5-year transition period that allows LTCHs to receive payments based partially on the reasonable cost-based methodology. In order to maintain budget neutrality as required by section 123(a)(1) of the Pub. L. 106–113 and § 412.523(d)(2) during the 5-year transition period, we reduce all LTCH Medicare payments (whether a LTCH elects payment based on 100 percent of the Federal rate or whether a LTCH is being paid under the transition blend methodology). Specifically, we reduce all LTCH Medicare payments during the 5-year transition by a factor that is equal to 1 minus the ratio of the estimated TEFRA reasonable cost-based payments that would have been made if the LTCH PPS had not been implemented, to the projected total Medicare program PPS payments (that is, payments made under the transition methodology and the option to elect payment based on 100 percent of the Federal rate).

In the June 6, 2003, final rule (68 FR 34512), based on the best available data, we projected that a certain percentage of LTCHs would elect to be paid based on 100 percent of the standard Federal rate rather than receive payment based on the transition blend methodology. As discussed in that same final rule, using the same methodology established in the August 30, 2002, final rule (67 FR 56034), this projection was based on our estimate that either: (1) a LTCH has already elected payment based on 100 percent of the Federal rate prior to the beginning of the 2004 LTCH PPS rate year (July 1, 2003); or (2) a LTCH will receive higher payments based on 100 percent of the standard Federal rate compared to the payments they would receive under the transition blend methodology. Similarly, we projected that the remaining LTCHs would choose to be paid based on the transition blend methodology at § 412.533 because those payments would be higher than if they were paid based on 100 percent of the standard Federal rate.

In the June 6, 2003, final rule (68 FR 34513), we projected that the full effect of the remaining 4 years of the transition period, including the election option, will result in a cost to the Medicare program of $310 million. Specifically, for the 2005 LTCH PPS rate year, we estimated that the cost of the transition would be $100 million. This cost would have necessitated an estimated budget neutrality offset of 4.6 percent (0.954) for payments to LTCHs in the 2005 rate year. Furthermore, in order to maintain budget neutrality, we indicated that, in the future, we would propose a budget neutrality offset for each of the remaining years of the transition period to account for the estimated payments for the respective fiscal year.

For the proposed 2005 LTCH PPS rate year, based on the best available data, we are projecting that approximately 69 percent of LTCHs would be paid based on 100 percent of the proposed standard Federal rate rather than receive payment under the transition blend methodology. Using the same methodology described in the August 30, 2002, final rule (67 FR 56034), this projection, which uses updated data and inflation factors, is based on our estimate that either—(1) a LTCH has already elected payment based on 100 percent of the Federal rate prior to the start of the 2005 LTCH PPS rate year (July 1, 2004); or (2) a LTCH would receive higher payments based on 100 percent of the proposed 2005 LTCH PPS rate year standard Federal rate compared to the payments it would receive under the transition blend methodology. Similarly, we are projecting that the remaining 31 percent of LTCHs would choose to be paid based on the applicable transition blend methodology (as set forth under § 412.533(a)) because they would receive higher payments than if they were paid based on 100 percent of the proposed 2005 LTCH PPS rate year standard Federal rate. The applicable transition blend percentage is applicable for a LTCH's entire cost reporting period beginning on or after October 1 (unless the LTCH elects payment based on 100 percent of the Federal rate).

In this proposed rule, based on the best available data and the proposed policy revisions described above, we project that the full effect of the remaining 4 years of the transition period (including the election option) would result in a cost to the Medicare program of $170 million as follows:

LTCH PPS rate year	Estimated cost (in millions)
2005	$80
2006	50
2007	30
2008	10

We note that although the transition period will have ended for most LTCHs by the 2008 LTCH PPS rate year, a small cost is projected for the 2008 LTCH PPS rate year (July 1, 2007, through June 30, 2008) because the applicable transition period percentages are based on a LTCH's individual cost reporting period and not the LTCH PPS rate year (July 1 through June 30). Specifically, LTCHs with cost reporting periods beginning July 1, 2006, through October 1, 2006 (during the 4th year of the transition period), where the applicable transition blend percentages are 20 percent based on reasonable cost and 80 percent based on the Federal rate (*see* § 412.533), will end during the first 3 months of the 2008 LTCH PPS rate year (July 1, 2007, through September 30, 2007). Therefore, a small cost is projected for the 2008 LTCH PPS rate year to account for those LTCHs that will still be receiving blended transition payments for a portion of the 2008 LTCH PPS rate year.

Accordingly, using the methodology established in the August 30, 2002, final rule (67 FR 56034) based on updated data and the proposed policies and rates discussed in this proposed rule, we are proposing a 3.0 percent reduction (0.970) to all LTCHs' payments for discharges occurring on or after July 1, 2004, and through June 30, 2005, to account for the estimated cost of the transition period methodology (including the option to elect payment based on 100 percent of the Federal rate) of the $80 million for the 2005 LTCH PPS rate year.

This offset of 3.0 percent has decreased relative to the estimate of 4.6 percent for several reasons. For this proposed rule, we have used data from more recent cost reports and were able to obtain data from more LTCHs (211 LTCHs as compared to 194 LTCHs in the June 6, 2003, final rule). In addition, in projecting the percentage of hospitals that would elect to be paid based on 100 percent of the proposed 2005 LTCH PPS rate year standard Federal rate, we used the Provider Specific File (PSF) in which LTCHs indicated whether they opted to be paid based on 100 percent of standard Federal rate or the transition blend methodology for the FY 2003 LTCH PPS payment year. However, based on information obtained from the PSF, we learned that, for those LTCHs that we projected would choose payment for FY 2003 based on 100 percent of the standard Federal rate (where payment based on the full Federal rate would be expected to be higher for those LTCHs than payment under the transition blend methodology), a significant number of those LTCHs chose to be paid under the transition blend methodology that is projected to result in payment lower than that using 100 percent of the standard Federal rate.

Similarly, a significant number of those LTCHs that we expected would choose payment under the transition blend methodology (where payment under the transition blend for those LTCHs would be expected to be higher than payment based on 100 percent of the standard Federal rate) chose to be paid using 100 percent of the standard Federal rate, which is projected to result in payment lower than that under the transition blend methodology. Since a number of LTCHs opted to be paid based on a methodology in which they would receive lower payments, we assume that the overall cost of $100 million to the Medicare program of the transition period would be less than what was projected in the June 6, 2003, final rule for the proposed 2005 LTCH PPS rate year. Thus, in the June 6, 2003, final rule, in estimating the $100 million cost to the transition, which would have necessitated a 4.6 percent reduction to all LTCHs' payments for the 2005 LTCH PPS rate year, we overstated our assumptions of the cost of the transition period. Accordingly, to account for the projected lower cost of the transition period due to those LTCHs that chose to be paid based on a methodology in which they would receive lower payments in FY 2003, for this proposed rule, we are proposing a 3.0 percent (0.970) reduction to all LTCHs' payments during the 2005 LTCH PPS rate year. We note that the proposed 0.970 transition period budget neutrality factor for the 2005 LTCH PPS rate year is 3 percentage points lower than the transition period budget neutrality factor for the 2004 LTCH PPS rate year (0.940). This smaller budget neutrality offset contributes to greater LTCH payment increases between the 2004 and 2005 LTCH PPS rate years compared to the increases seen between FY 2003 and the 2004 LTCH PPS rate year. We do not expect to see these large payment per discharge increases in future years as the majority of LTCHs will have transitioned fully to the LTCH PPS and, therefore, the transition period budget neutrality factor should remain more stable.

As noted above, in order to maintain budget neutrality, we indicated that we would propose a budget neutrality offset for each of the remaining years of the transition period to account for the estimated costs for the respective LTCH PPS rate years. In this proposed rule, based on the best available data, we are proposing the following budget neutrality offsets to the LTCH PPS during the remaining years of the transition period: 2.2 percent (0.978) for the 2006 LTCH PPS rate year, 1.1 percent (0.989) for the 2007 LTCH PPS rate year, and 0.1 percent (0.990) for the 2008 LTCH PPS rate year. As noted above, the small offset in the 2008 LTCH PPS rate year accounts for those LTCHs whose blended transition period payments will be concluding in the first 3 months of the 2008 LTCH PPS rate year (that is, July 1, 2007, through September 30, 2007).

As we discussed in the August 30, 2002, final rule (67 FR 56036), consistent with the statutory requirement for budget neutrality in section 123(a)(1) of Public Law 106–113, we intended for estimated aggregate payments under the LTCH PPS to equal the estimated aggregate payments that would be made if the LTCH PPS was not implemented. Our methodology for estimating payments for purposes of the budget neutrality calculations use the best available data at that time and necessarily reflect assumptions. As the LTCH PPS progresses, we are monitoring payment data and will evaluate the ultimate accuracy of the assumptions used in the budget neutrality calculations (for example, inflation factors, intensity of services provided, or behavioral response to the implementation of the LTCH PPS) described in the August 30, 2002, final rule (67 FR 56027–56037). To the extent these assumptions significantly differ from actual experience, the aggregate amount of actual payments may turn out to be significantly higher or lower than the estimates on which the budget neutrality calculations were based.

Section 123 of Pub. L. 106–113 and section 307 of Pub. L. 106–554 provide broad authority to the Secretary in developing the LTCH PPS, including the authority for appropriate adjustments. Under this broad authority, as implemented in the regulations at § 412.523(d)(3), we have provided for the possibility of making a one-time prospective adjustment to the LTCH PPS rates by October 1, 2006, so that the effect of any significant difference between actual payments and estimated payments for the first year of the LTCH PPS would not be perpetuated in the LTCH PPS rates for future years.

In the June 6, 2003, final rule (67 FR 34153), we estimated that total Medicare program payments for LTCH services over the next 5 LTCH PPS rate years would be $2.17 billion for the 2004 LTCH PPS rate year; $2.29 billion for the 2005 LTCH PPS rate year; $2.42 billion for the 2006 LTCH PPS rate year; $2.56 billion for the 2007 LTCH PPS rate year; and $2.71 billion for the 2008 LTCH PPS rate year.

Consistent with the methodology discussed in the June 6, 2003, final rule (68 FR 34138), in this proposed rule, based on the most recent available data, we estimate that total Medicare program payments for LTCH services for the next 5 LTCH PPS rate years would be as follows:

LTCH PPS rate year	Estimated payments ($ in billions)
2005	$2.33
2006	2.48
2007	2.64
2008	2.79
2009	2.96

As noted above, in accordance with the methodology established in the August 30, 2002, final rule (67 FR 56037), these estimates are based on the projection that 69 percent of LTCHs would elect to be paid based on 100 percent of the proposed 2005 LTCH PPS rate year standard Federal rate rather than the applicable transition blend, and our estimate of 2005 LTCH PPS rate year payments to LTCHs using our Office of the Actuary's most recent estimate of the excluded hospital with capital market basket of 2.9 percent for the 2005 LTCH PPS rate year, 3.2 percent for the 2006 LTCH PPS rate year, 3.1 percent for the 2007 LTCH PPS rate year, 3.0 percent for the 2008 LTCH PPS rate year, and 3.2 percent for the 2009 LTCH PPS rate year. We also took into account our Office of the Actuary's projection that there would be an increase in Medicare beneficiary enrollment of 2.1 percent in the 2005 LTCH PPS rate year, 2.4 percent in the 2006 LTCH PPS rate year, 2.1 percent in the 2007 LTCH PPS rate year, 2.0 percent in the 2008 LTCH PPS rate year, and 2.1 percent in the 2009 LTCH PPS rate year.

Because the LTCH PPS has only been implemented for less than 2 years, sufficient new data have not been generated that would enable us to conduct a comprehensive reevaluation of our budget neutrality calculations. Therefore, in this proposed rule, we are not proposing to make a one-time adjustment under § 412.523(d)(3) so that the effect of any significant difference between actual payments and estimated payments for the first year of the LTCH PPS is not perpetuated in the PPS rates for future years. However, we will continue to collect and interpret new data as the data become available in the future to determine if such an adjustment should be proposed.

7. Proposed Changes in the Procedure for Counting Days in the Average Length of Stay Calculation

Prior to the implementation of the PPS for LTCHs, Medicare paid LTCHs under the reasonable cost methodology subject to limitations on payments. Both the BBRA and BIPA required the development and implementation of a per discharge PPS for LTCHs based on DRGs for cost reporting periods beginning on or after October 1, 2002 (67 FR 55954, August 30, 2002).

Under the reasonable cost-based reimbursement system, the number of patient days that occurred during a cost reporting period and the costs associated with those days were reported on the hospital's cost report (Hospital and Hospital Health Care Complex Cost Report, CMS Form 2552–96), as were the number of patient discharges that occurred during that same period. This method of reporting and reimbursement did not require that all of the days of care to a patient be counted as occurring in the cost reporting period during which the patient was discharged. Under this method of reporting and reimbursement the days of care to a patient are counted in the cost reporting period in which it occurred.

With the FY 2003 implementation of the LTCH PPS, as in other discharge-based PPS'', such as those for acute care hospitals and for IRFs, all days of the patient's stay, even those occurring prior to the cost reporting period in which the discharge occurs are counted for payment purposes as occurring in the cost reporting period of the patient's discharge. An example of this distinction is as follows: A LTCH has a January 1 through December 31 cost reporting period; a Medicare patient is admitted on December 15 and discharged on February 5, 2004. Prior to the LTCH PPS, under the reasonable cost-based reimbursement system, costs and patient days occurring in December 2003 would be included in the January 1 through December 31, 2003, cost reporting period, even though the patient was not discharged until February of the next cost reporting period that began January 1, 2004. Those patient days occurring in January and February would be counted in the next cost reporting period (2004) in which the discharge occurred. Since the implementation of the LTCH PPS, for payment purposes, *all* patient days for this stay would be reported in the cost reporting period in which the discharge occurred. In the above example, therefore, all of the patient stay would be counted in the next cost reporting period which is the 2004 cost reporting period. Even if a LTCH is transitioning into fully Federal payments and a percentage of its payments is based upon what would have been paid under the former reasonable cost-based reimbursement system, under §§ 412.500 and 412.533, payment policy is governed by the LTCH PPS. At cost report settlement, payment is discharge-based. Therefore, once a LTCH is subject to the LTCH PPS, that is, for its first cost reporting period starting on or after October 1, 2002, the "days follow the discharge," which means that both days and costs are linked to the patient's discharge, even when the days occurred in a previous cost reporting period.

In the August 30, 2002, final rule (67 FR 55972), which established the policies of the LTCH PPS, we stated that "[t]he procedure by which a LTCH will be evaluated by its fiscal intermediary to determine whether it will qualify as a LTCH * * * is the same procedure currently employed under the TEFRA system." Currently, for determining whether a hospital meets the greater than 25 day average Medicare inpatient length of stay criterion, in the case of a Medicare patient who was admitted during one cost reporting period, but was discharged in a following cost reporting period, both covered and uncovered days are counted in the cost reporting period in which they occurred and not linked to the cost reporting period in which the patient is discharged.

Therefore, presently, for a LTCH with a January 1 through December 31 cost reporting period, if a patient was admitted on December 1, 2002, and discharged on January 15, 2003, patient days would be counted one way for payment purposes and another way for purposes of counting the average length of stay. For payment purposes, all 46 days of the stay and the costs associated with them would be reported during the cost reporting period that the discharge occurred, that is, January 1, 2003, through December 31, 2003. For purposes of determining whether a hospital meets the greater than 25 day length of stay criterion, under § 412.23(e)(2)(i), however, for the same patient, the 31 days in December would be counted as occurring during the January 1, 2002, to December 31, 2002, cost reporting period and the 15 days in January 2003 would be counted, along with the discharge, during the January 1, 2003, through December 31, 2003, cost reporting period.

We have received numerous inquiries from providers and fiscal intermediaries indicating that our two different ways of counting days under the LTCH PPS for payment and for average length of stay calculations have created considerable confusion. Therefore, in response to these inquiries and consistent with the payment system already in place for LTCHs as discussed above, in this proposed rule, we are proposing to revise § 412.23(e)(3)(i) of the regulations to specify that if a patient's stay includes days of care furnished during two or more separate consecutive cost reporting periods, the total days of a patient's stay would be reported in the cost reporting period during which the patient is discharged in calculating the average length of stay for hospitals that qualify as LTCHs under both § 412.23(e)(2)(i) and (ii). We are not proposing any changes to the formula of dividing the number of total days for Medicare patients by discharges for LTCHs in order to determine whether a hospital qualifies as a LTCH under § 412.23(e)(2)(i) or in the formula of dividing total days for all patients by discharges for LTCHs to qualify under § 412.23(e)(2)(ii).

In the August 1, 2003, final rule for the IPPS (68 FR 45464), we discussed the inability of the present cost report (Hospital and Hospital Health Care Complex Cost Report, CMS Form 2552–96) to capture total days for Medicare patients as required under §§ 412.23(e)(2) and (e)(3) for hospitals qualifying under § 412.23(e)(2)(i) and our present use of census data gathered from the Medicare provider analysis and review (MedPAR) files for this purpose. Prior to the October 1, 2002, implementation of the LTCH PPS, we relied on data from the most recently submitted hospital cost report in order to determine whether or not a hospital qualified as a LTCH. We would continue to utilize patient days and discharge data from MedPAR files for the qualification calculation under the proposed revised § 412.23(e)(3)(i) until the cost reporting form is revised to capture total days for Medicare inpatients.

As discussed earlier, for a hospital to qualify as a LTCH under § 412.23(e)(2)(i), it must demonstrate that the Medicare inpatients require care for an average Medicare inpatient length of stay of greater than 25 days for the hospital's most recent cost reporting period. Alternatively, for cost reporting periods beginning on or after August 5, 1997, a hospital that was first excluded from the PPS in 1986, and can demonstrate that at least 80 percent of its annual Medicare inpatient discharges in the 12-month cost reporting period ending in FY 1997 have a principal diagnosis that reflects a finding of neoplastic disease must have an average inpatient length of stay for all patients, including both Medicare and non-Medicare inpatients, of greater than 20 days (§ 412.23(e)(2)(ii)). As described above, under the previous reasonable cost-based reimbursement system to determine whether or not a hospital met this requirement, total days for all patients were divided by the total number of discharges that occurred during a cost reporting period. When we implemented the LTCH PPS on October 1, 2002, we limited this calculation to only Medicare patients for hospitals to qualify under § 412.23(e)(2)(i), but did not change the calculation for hospitals to qualify under § 412.23(e)(2)(ii). As we noted in the August 30, 2002, final rule, "[w]e believe that excluding non-Medicare patients in determining the average inpatient length of stay for purposes of subclause (I) would be more appropriate in identifying the hospitals that warrant exclusion under the general definition of LTCH in subclause (I). However in enacting subclause (II), the Congress provided an exception to the general definition of LTCH under subclause (I), and we have no reason to believe that the change in methodology for determining the average inpatient length of stay would better identify the hospitals that the Congress intended to exclude under subclause (II) (67 FR 55974). These hospitals will continue to have their greater than 20 days average length of stay calculated based on all days for all patients, whether Medicare or non-Medicare patients, and will continue to be determined based on the days of care provided during the cost reporting period and not based solely on the count of days for the patients discharged during the cost reporting period.

8. Clarification of the Requirements for a Satellite Facility or a Remote Location To Qualify as a LTCH and Proposed Changes to the Requirements for Certain Satellite Facilities and Remote Locations

a. Proposed Policy Change

In § 412.22(h)(1), we define a satellite as "a part of a hospital that provides inpatient services in a building also used by another hospital, or in one or more entire buildings located on the same campus as buildings used by another hospital." Satellite arrangements exist when a IPPS excluded hospital is either a freestanding hospital or a hospital-within-a-hospital under § 412.22(e) that establishes an additional location by sharing space in a building also used by another hospital, or in one or more entire buildings located on the same campus as buildings used by another hospital. A detailed discussion of our policies regarding Medicare payments for satellite facilities of hospitals excluded from the IPPS was set forth in the IPPS final rules published on July 30, 1999 (64 FR 41532–41534), and August 1, 2003 (67 FR 49982).

We established Medicare regulations regarding satellite facilities for several reasons. First, we believe that whenever a facility that is co-located with an acute care hospital is presented as part of another IPPS-excluded hospital, it is necessary to ensure that the facility is, in fact, organized and operated as part of the IPPS-excluded hospital and is not simply a unit of the acute hospital with which it is co-located. Although we recognize that the co-location of Medicare providers, in the form of satellite facilities, hospitals-within-hospitals, and excluded units, may have some legitimate advantages from the standpoint of clinical care as well as medical efficiency, we continue to believe that the physical proximity inherent in such arrangements also has considerable potential for Medicare program payment abuse in that it may facilitate patient shifting for reasons related to payment rather than clinical benefits. In existing regulations at § 412.22(e) for hospitals-within-hospitals (59 FR 45330, September 1, 1994), at § 412.23(h) for hospital satellites (64 FR 41532–41534, July 30, 1999, and 67 FR 49982, August 1, 2002), and § 412.25(e) for satellite facilities, we promulgated "separateness and control" requirements governing the relationships between these facilities and their host hospitals.

Research by the Urban Institute on the universe of LTCHs that was used in developing the LTCH PPS pointed to the considerable growth of new LTCHs (or LTCH beds, as in the case of satellite facilities) that were co-located with other Medicare providers. Our more recent data confirm that this trend has continued. Even though our existing regulations governing hospitals-within-hospitals and satellite facilities established certain functional boundaries between these entities and their hosts, we instituted a policy under the LTCH regulations at § 412.532 to discourage inappropriate patient discharges and readmissions among co-located Medicare providers (67 FR 56007–56010, August 30, 2002). Furthermore, in the June 6, 2003, LTCH PPS final rule (68 FR 34157), we noted that we are monitoring the movement of patients among onsite providers for the purpose of determining whether we should consider proposing further changes to LTCH coverage and payment policy.

LTCH hospitals-within-hospitals and LTCH satellite facilities are similar in that both are located on the same campus or in the same building as another hospital, and many of the same separateness and control regulations exist for both types of facilities. However, there is an important distinction between them. A LTCH that is co-located with another Medicare hospital (generally an acute care hospital) is itself a distinct hospital (§ 412.22(e)). Section 412.23(e)(1) requires a LTCH to have a provider agreement as described under 42 CFR Part 489 to participate as a hospital. A satellite facility of a LTCH, like all satellite facilities of hospitals excluded from the IPPS (§ 412.22(h)), is not itself a separate hospital, but a "part of a hospital that provides inpatient services in a building also used by another hospital * * *" Consistent with its status as another hospital, a hospital-within-a-hospital has its own Medicare provider number. A satellite facility shares the provider number of the parent hospital.

Because a satellite facility is not considered a separate hospital under Medicare, if a LTCH with a satellite facility is interested in "spinning off" the satellite facility and establishing the previous satellite facility as an independent LTCH, the satellite must first be separately licensed by the State. The facility must further demonstrate compliance with the Medicare conditions of participation (COPS) under part 482 and other requirements for establishing a provider agreement under parts 482 and 489 to participate under Medicare as a hospital (§ 412.23(e)(1)). (Compliance with the COPS may be either demonstrated by a State agency survey or based on accreditation as a hospital by the Joint Commission on Accreditation of Healthcare Organizations (JCAHO or the American Osteopathic Association (AOA) (section 1865 of the Act).) Second, if the newly established hospital meets the provider agreement requirements under 42 CFR part 489, it must demonstrate that it has an average Medicare inpatient length of stay of greater than 25 days (§ 412.23(e)(2)(i)) by providing data of a period of at least 5 months of the preceding 6-month period (§ 412.22(e)(3)(ii) and (iii)). The data used by the fiscal intermediary to calculate the average length of stay would be from discharges from the newly established hospital and not from discharges attributable to stays at the previous satellite facility for the period prior to its participation as a separate hospital.

Although we believe that these requirements, under existing § 412.23(e)(1) and (2), are clear and unambiguous, we have been informed that due to misinterpretation, in some circumstances, application of this policy has been inconsistent. Therefore, some facilities operating as LTCH satellite facilities have been inappropriately granted autonomous status that has resulted in the assignment of their own Medicare provider numbers as LTCHs without first obtaining provider agreements to participate in Medicare as hospitals, under § 412.23(e)(1). Apparently, in these cases, the satellite facilities were able to demonstrate that as *satellite facilities* of LTCHs, Medicare patients at their location had an average length of stay of greater than 25 days, in compliance with § 412.22(h)(2)(ii) which required satellite facilities of hospitals excluded from the IPPS to comply with specific requirements for their provider category. In other situations, we understand that fiscal intermediaries correctly refused to accept data from LTCH satellite facilities for purposes of qualification as an autonomous LTCH and instead required the satellites to satisfy criteria for designation as a hospital, under § 412.23(e)(1). In these cases, the fiscal intermediary evaluated average length of stay data dating from that hospital designation forward, as required by § 412.23(e)(2).

We believe consistency in the application of this policy is needed, in compliance with existing regulations at § 412.23(e)(1) and (e)(2). We are emphasizing that a LTCH satellite facility that is "a part of a hospital that provides inpatient services in a building also used by another hospital * * *" that is seeking to become an independent LTCH, must comply with the requirements set forth in the definition of a new LTCH in existing § 412.23(e)(4). Therefore, we are proposing to revise § 412.23(e)(4) to include a new paragraph (e)(4)(ii) that specifies that only data reflecting the average length of stay for Medicare patients in the newly established hospital will be utilized in the qualifying calculation at § 412.23(e)(2). Thus, we are proposing clarifying language that emphasizes that if a satellite facility is reorganized as a separately participating hospital under Medicare with or without a concurrent change of ownership, the new hospital cannot be paid under Medicare as a LTCH until it demonstrates that it has an average Medicare inpatient length of stay in excess of 25 days based on discharges occurring on or after its effective date of participation as a hospital and not based on discharges at the satellite facility site when it was part of another hospital (proposed § 412.23(e)(4)(ii)).

This proposed policy clarification would also be applicable to remote locations of LTCHs that are being voluntarily separated from the parent LTCHs or sold and are seeking status as independent LTCHs. A remote location of a hospital (as defined at § 413.65(a)(2)) is similar to a satellite facility because it does not participate in Medicare as a separate hospital, but only as an integral and subordinate part of another hospital. However, unlike a satellite facility, a remote location is not one that is in the same building or on the same campus as another hospital. (Because a remote location has no "host" hospital, it is not required to meet the separateness criteria as hospitals-within-hospitals in § 412.22(e) that would arise for satellite facilities that become independent LTCHs, as discussed above.) Since the hospital would not be a LTCH until the fiscal intermediary reviews its documentation and determines that it qualifies, during those initial months, the hospital would be paid under the IPPS.

We emphasize that notwithstanding the fact that satellite facilities of LTCHs are required to independently meet the average Medicare inpatient length of stay requirement of greater than 25 days under § 412.22(h)(2)(ii)(D), we are proposing to evaluate length of stay data only from discharges occurring after the facility has become a hospital. This is the case as the prerequisite to designation as a LTCH is a provider agreement under part 489 of chapter IV to participate *as a hospital* in the Medicare program (§ 412.23(e)(1)). The requirement that a satellite facility independently meets the length of stay criterion was never intended as an alternative method of qualifying as a separate excluded hospital. Under § 412.23(h)(2)(ii), satellite facilities of psychiatric, rehabilitation, and children's hospitals, as well as LTCHs, are required to meet specific requirements for their provider category because we believed that it was essential to ensure that satellite facilities of excluded hospitals actually delivered the specialized care for which Medicare was paying (§ 412.23(h)(2)(ii)). Furthermore, those regulations were designed to ensure that there is both an appropriate financial and administrative linkage between the satellite facility and the parent hospital, and a clear separation of the satellite facility from the host hospital. These policies are set forth in the July 30, 1999, IPPS final rule (64 FR 41534). In the case of a LTCH, we believe that our existing requirement that a satellite facility independently meet the greater than 25-day average Medicare inpatient length of stay requirement is consistent with the guiding principles of the LTCH PPS. We do not believe patients who do not require long-term hospital-level care should be admitted to either a LTCH or its satellite facility. In addition, we were concerned that, without requiring separate compliance, shorter lengths of stay at either the LTCH or its satellite facility could be balanced by longer stays at the other. By establishing these distinct standards for satellite facilities of excluded hospitals, we also wanted to safeguard against the possibility of these facilities functioning as a part of an acute care hospital. In the case of a LTCH, that result would be inconsistent with section 1886(d)(1)(B) of the Act, which provides for excluded rehabilitation and psychiatric units to be established in acute care hospitals, but not long-term care units.

There is another situation that must be distinguished from the scenario discussed above in which a LTCH is voluntarily separating from or selling its satellite facility or remote location with the intent of the satellite facility or remote location converting into an independent hospital and eventually a LTCH. Our recent provider-based regulations under § 413.65 require a remote location of a hospital that fails to meet certain requirements at § 413.65(e)(3) to seek status as a separate hospital if it is to continue functioning and being paid by Medicare. Satellite facilities of excluded hospitals, such as LTCHs, may also be affected by these new provider-based requirements and, in those cases, the following procedure would also be applicable.

Under the provider-based regulations, which became effective for the main providers as defined in § 413.65(a)(2), for cost reporting periods beginning on or after July 1, 2003, certain facilities that were formerly treated for payment purposes by Medicare as remote locations or satellite facilities of hospitals, are now precluded from continuing in that status because they do not meet the "common service area" location requirement for provider-based facilities under § 413.65(e)(3) (67 FR 50078, August 1, 2002). It has come to our attention that certain satellite facilities and remote locations of LTCHs are being affected by this preclusion. Due to the compulsory nature of this separation requirement, we are proposing an exception for these affected satellite facilities and remote locations of LTCHs that will allow them to utilize length of stay data from the 5 months of the previous 6 months prior to when they were compelled to separate from their main provider under § 413.65(e)(3) (proposed § 412.23(e)(4)(iii)).

We want to emphasize that the only distinction that we are proposing between requirements proposed under § 412.23(e)(4)(ii), for satellite facilities and remote locations that voluntarily separate from their parent LTCHs and requirements in proposed § 412.23(e)(4)(iii) that apply to satellite facilities and remote locations compelled by provider-based location requirements at § 413.65(e)(3) to terminate their link to their main providers, is that we are proposing to allow the latter group to utilize data gathered prior to establishing themselves as distinct hospitals. Furthermore, this distinction only exists for satellite facilities and remote locations of LTCHs that are affected by (§ 413.65(e)(3)) and which were in existence prior to the effective date of the provider-based location requirements (July 1, 2003). Under the regulations at § 413.65(e)(3), we would not permit these entities to be established more than 35 miles from the main providers after June 30, 2003. We would assign new Medicare provider numbers to former remote locations of LTCH hospitals or satellite facilities that fail the new location requirement in § 413.65(e)(3), but want to become new LTCHs, if the following conditions are satisfied in proposed § 412.23(e)(4)(iii):

- The facility meets all Medicare COPs in 42 CFR Part 482 and other participation requirements set forth in 42 CFR Part 489.
- The facility provides data to its fiscal intermediary indicating that during 5 of the immediate 6 months *preceding its separation from the main hospital,* it has independently met the greater than 25-day average length of stay requirement for its Medicare patients (§ 412.23(e)(3)).

b. Technical Correction

In the August 30, 2002, LTCH PPS final rule (67 FR 56053), we issued regulations at § 412.532(i) that require a LTCH or a satellite of a LTCH to notify its fiscal intermediary and CMS in writing of its co-location and any changes in co-location status. In § 412.532(i), we include a cross-reference to the Medicare regulations that contain the requirements for a satellite facility to be paid under Medicare. We made an unintentional error in specifying this cross-reference as paragraphs (h)(1) through (h)(4) of § 412.532. The correct cross-reference to the requirements for satellite facilities is § 412.22(h)(1) through (h)(4). Therefore, we are proposing to revise § 412.532(i) to include the correct cross-reference to § 412.22(h)(1) through (h)(4).

V. Computing the Proposed Adjusted Federal Prospective Payments for the 2005 LTCH PPS Rate Year

(If you choose to comment on issues in this section, please include the caption "COMPUTING THE PROPOSED ADJUSTED FEDERAL PROSPECTIVE PAYMENTS" at the beginning of your comments.)

In accordance with § 412.525 and as discussed in section IV.C. of this proposed rule, the proposed standard Federal rate is adjusted to account for differences in area wages by multiplying the labor-related share of the proposed standard Federal rate by the appropriate proposed LTCH PPS wage index (as shown in Tables 1 and 2 of the Addendum to this proposed rule). The proposed standard Federal rate is also adjusted to account for the higher costs of hospitals in Alaska and Hawaii by multiplying the nonlabor-related share of the proposed standard Federal rate by the appropriate proposed cost-of-living factor (shown in Table I in section IV.C.2. of this preamble). In this proposed rule, as discussed in section IV.B. of this preamble, we are proposing a standard Federal rate of $36,762.24 for the 2005 LTCH PPS rate year. We illustrate the methodology used to adjust the proposed Federal prospective payments in the following example:

During the 2005 LTCH PPS rate year, a Medicare patient is in a LTCH located in Chicago, Illinois (MSA 1600) with a proposed two-fifths wage index value of 1.0357 (*see* Table 1 in the Addendum to this proposed rule). The Medicare patient is classified into LTC–DRG 9 (Spinal Disorders and Injuries), which has a relative weight of 1.5025 (*see* Table 3 of the Addendum to this proposed rule). To calculate the LTCH's total adjusted proposed Federal prospective payment for this Medicare patient, we compute the wage-adjusted proposed Federal prospective payment amount by multiplying the unadjusted proposed standard Federal rate ($36,762.24) by the labor-related share (72.885 percent) and the proposed wage index value (1.0357). (We note that the LTCH in this example is in the second year of the wage index phase-in, thus, the two-fifths wage index value is applicable.) This wage-adjusted amount is then added to the nonlabor-related portion of the unadjusted proposed standard Federal rate (27.115 percent; adjusted for cost of living, if applicable) to determine the adjusted proposed Federal rate, which is then multiplied by the LTC–DRG relative weight (1.5025) to calculate the total adjusted proposed Federal prospective payment for the 2005 LTCH PPS rate year ($56,672.48). In addition, as discussed in section IV.C.6. of this preamble, for the 2005 LTCH PPS rate year, we are proposing to reduce the LTCH PPS payment by 3.0 percent for the budget neutrality offset to account for the costs of the transition methodology. The following illustrates the components of the calculations in this example:

Unadjusted Proposed Standard Federal Prospective Payment Rate	$36,762.24
Labor-Related Share	×0.72885
Labor-Related Portion of the Proposed Federal Rate	=$26,794.16
Proposed ⅖th Wage Index (MSA 1600)	×1.0357
Wage-Adjusted Labor Share of Proposed Federal Rate	=$27,750.71
Nonlabor-Related Portion of the Proposed Federal Rate ($36,762.24 × 0.27115)	+$ 9,968.08
Adjusted Proposed Federal Rate Amount	=$37,718.79
LTC–DRG 4 Relative Weight	×1.5025
Total Adjusted Proposed Federal Prospective Payment (Before the Proposed Budget Neutrality Offset)	=$56,672.48
Proposed Budget Neutrality Offset	×0.970
Total Proposed Federal Prospective Payment (Including the Proposed Budget Neutrality Offset)	=$54,972.31

VI. Transition Period

(If you choose to comment on issues in this section, please include the caption "TRANSITION PERIOD" at the beginning of your comments.)

To provide a stable fiscal base for LTCHs, under § 412.533, we implemented a 5-year transition period from reasonable cost-based reimbursement under the TEFRA system to a prospective payment based on industry-wide average operating and capital-related costs. Under the average pricing system, payment is not based on the experience of an individual hospital. As discussed in the August 30, 2002 final rule (67 FR 56038), we believe that a 5-year phase-in provides LTCHs time to adjust their operations and capital financing to the LTCH PPS, which is based on prospectively determined Federal payment rates. Furthermore, we believe that the 5-year phase-in of the LTCH PPS also allows LTCH personnel to develop proficiency with the LTC-DRG coding system, which will result in improvement in the quality of the data used for generating our annual determination of relative weights and payment rates.

In accordance with § 412.533, the transition period for all hospitals subject to the LTCH PPS begins with the hospital's first cost reporting period beginning on or after October 1, 2002, and extends through the hospital's last cost reporting period beginning before October 1, 2006. During the 5-year transition period, a LTCH's total payment under the LTCH PPS is based on two payment percentages—one based on reasonable cost-based (TEFRA) payments and the other based on the standard Federal prospective payment rate. The percentage of payment based on the LTCH PPS Federal rate increases by 20 percentage points each year, while the reasonable cost-based payment rate percentage decreases by 20 percentage points each year, for the next 3 fiscal years. For cost reporting periods beginning on or after October 1, 2006, Medicare payment to LTCHs will be determined entirely under the Federal PPS methodology. The blend percentages as set forth in § 412.533(a) are as follows:

Cost reporting periods beginning on or after	Federal rate percentage	Reasonable cost principles rate percentage
October 1, 2002	20	80
October 1, 2003	40	60
October 1, 2004	60	40
October 1, 2005	80	20
October 1, 2006	100	0

For cost reporting periods that begin on or after October 1, 2003, and before October 1, 2004 (FY 2004), the total payment for a LTCH is 60 percent of the amount calculated under reasonable cost principles for that specific LTCH and 40 percent of the Federal prospective payment amount. For cost reporting periods that begin on or after October 1, 2004, and before October 1, 2005 (FY 2005), the total payment for a LTCH will be 40 percent of the amount calculated under reasonable cost principles for that specific LTCH and 60 percent of the Federal prospective payment amount. As we noted in the June 6, 2003, final rule (68 FR 34155), the change in the effective date of the annual LTCH PPS rate update from October 1 to July 1 has no effect on the LTCH PPS transition period as set forth in § 412.533(a). That is, LTCHs paid under the transition blend under § 412.533(a) will receive those blend percentages for the entire 5-year transition period (unless they elect payments based on 100 percent of the Federal rate). Furthermore, LTCHs paid under the transition blend will receive the appropriate blend percentages of the Federal and reasonable cost-based rate for their entire cost reporting period as prescribed in § 412.533(a)(1) through (a)(5).

The reasonable cost-based rate percentage is a LTCH specific amount that is based on the amount that the LTCH would have been paid (under TEFRA) if the PPS were not implemented. Medicare fiscal intermediaries will continue to compute the LTCH reasonable cost-based payment amount according to § 412.22(b) of the regulations and sections 1886(d) and (g) of the Act.

In implementing the PPS for LTCHs, one of our goals is to transition hospitals to full prospective payments as soon as appropriate. Therefore, under § 412.533(c), we allow a LTCH, which is subject to a blended rate, to elect payment based on 100 percent of the Federal rate at the start of any of its cost reporting periods during the 5-year transition period rather than incrementally shifting from reasonable cost-based payments to prospective payments. Once a LTCH elects to be paid based on 100 percent of the Federal rate, it will not be able to revert to the transition blend. For cost reporting periods that began on or after December 1, 2002, and for the remainder of the 5-year transition period, a LTCH must notify its fiscal intermediary in writing of its election on or before the 30th day prior to the start of the LTCH's next cost reporting period. For example, a LTCH with a cost reporting period that begins on May 1, 2004, must notify its fiscal intermediary in writing of an election before April 1, 2004.

Under § 412.533(c)(2)(i), the notification by the LTCH to make the election must be made in writing to the Medicare fiscal intermediary. Under §§ 412.533(c)(2)(ii) and (c)(2)(iii), the intermediary must receive the request on or before the specified date (that is, on or before the 30th day before the applicable cost reporting period begins for cost reporting periods beginning on or after December 1, 2002 through September 30, 2006), regardless of any postmarks or anticipated delivery dates.

Notifications received, postmarked, or delivered by other means after the specified date will not be accepted. If the specified date falls on a day that the postal service or other delivery sources are not open for business, the LTCH will be responsible for allowing sufficient time for the delivery of the request before the deadline. If a LTCH's notification is not received timely, payment will be based on the transition period blend percentages.

VII. Payments to New LTCHs

(If you choose to comment on issues in this section, please include the caption "PAYMENTS TO NEW LTCHs" at the beginning of your comments.)

Under § 412.23(e)(4), for purposes of Medicare payment under the LTCH PPS, we define a new LTCH as a provider of inpatient hospital services that otherwise meets the qualifying criteria for LTCHs, set forth in § 412.23(e)(1) and (e)(2), under present or previous ownership (or both), and its first cost reporting period as a LTCH begins on or after October 1, 2002. We also specify in § 412.500 that the LTCH PPS is applicable to hospitals with a cost reporting period that began on or after October 1, 2002. (In section I.B.3. of this proposed rule, we clarify existing policy for the time frame for calculating the average length of stay of a new LTCH as it relates to a satellite facility or remote location of a LTCH that voluntarily seeks to become a separate LTCH. We are also proposing a policy for the time frame for calculating the average length of stay as it relates to a remote location of a hospital that fails to meet certain requirements at § 413.65 and is required to seek status as a separate LTCH.)

As we discussed in the August 30, 2002, final rule (67 FR 56040), this definition of new LTCHs should not be confused with those LTCHs first paid under the TEFRA payment system for discharges occurring on or after October 1, 1997, described in section 1886(b)(7)(A) of the Act, as added by section 4416 of Public Law 105–33. As stated in § 413.40(f)(2)(ii), for cost reporting periods beginning on or after October 1, 1997, the payment amount for a "new" (post-FY 1998) LTCH is the lower of the hospital's net inpatient operating cost per case or 110 percent of the national median target amount payment limit for hospitals in the same class for cost reporting periods ending during FY 1996, updated to the applicable cost reporting period (*see* 62 FR 46019, August 29, 1997). Under the LTCH PPS, those "new" LTCHs that meet the definition of "new" under § 413.40(f)(2)(ii) and that have their first cost reporting period as a LTCH beginning prior to October 1, 2002, will be paid under the transition methodology described in § 412.533.

As noted above and in accordance with § 412.533(d), new LTCHs will not participate in the 5-year transition from reasonable cost-based reimbursement to prospective payment. As we discussed in the August 30, 2002, final rule (67 FR 56040), the transition period is intended to provide existing LTCHs time to adjust to payment under the new system. Since these new LTCHs with cost reporting periods beginning on or after October 1, 2002, would not have received payment under reasonable cost-based reimbursement for the delivery of LTCH services prior to the effective date of the LTCH PPS, we do not believe that those new LTCHs require a transition period in order to make adjustments to their operations and capital financing, as will LTCHs that have been paid under the reasonable cost-based methodology.

VIII. Method of Payment

(If you choose to comment on issues in this section, please include the caption "METHOD OF PAYMENT" at the beginning of your comments.)

Under § 412.513, a Medicare LTCH patient is classified into a LTC–DRG based on the principal diagnosis, up to eight additional (secondary) diagnoses, and up to six procedures performed during the stay, as well as age, sex, and discharge status of the patient. The LTC–DRG is used to determine the Federal prospective payment that the LTCH will receive for the Medicare-covered Part A services the LTCH furnished during the Medicare patient's stay. Under § 412.541(a), the payment is based on the submission of the discharge bill. The discharge bill also provides data to allow for reclassifying the stay from payment at the full LTC–DRG rate to payment for a case as a short-stay outlier (under § 412.529) or as an interrupted stay (under § 412.531), or to determine if the case will qualify for a high-cost outlier payment (under § 412.525(a)).

Accordingly, the ICD–9–CM codes and other information used to determine if an adjustment to the full LTC–DRG payment is necessary (for example, length of stay or interrupted stay status) are recorded by the LTCH on the Medicare patient's discharge bill and submitted to the Medicare fiscal intermediary for processing. The payment represents payment in full, under § 412.521(b), for inpatient operating and capital-related costs, but not for the costs of an approved medical education program, bad debts, blood clotting factors, anesthesia services by hospital-employed nonphysician anesthetists or obtained under arrangement, or the costs of photocopying and mailing medical records requested by a QIO, which are costs paid outside the LTCH PPS.

As under the previous reasonable cost-based payment system, under § 412.541(b) a LTCH may elect to be paid using the periodic interim payment (PIP) method described in § 413.64(h) and may be eligible to receive accelerated payments as described in § 413.64(g).

For those LTCHs that are paid during the 5-year transition based on the blended transition methodology in § 412.533(a) for cost reporting periods that began on or after October 1, 2002, and before October 1, 2006, the PIP amount is based on the transition blend. For those LTCHs that are paid based on 100 percent of the standard Federal rate, the PIP amount is based on the estimated prospective payment for the year rather than on the estimated reasonable cost-based reimbursement. We exclude high-cost outlier payments that are paid upon submission of a discharge bill from the PIP amounts. In addition, Part A costs that are not paid for under the LTCH PPS, including Medicare costs of an approved medical education program, bad debts, blood clotting factors, anesthesia services by hospital-employed nonphysician anesthetists or obtained under arrangement, and the costs of photocopying and mailing medical records requested by a QIO, are subject to the interim payment provisions (§ 412.541(c)).

Under § 412.541(d), LTCHs with unusually long lengths of stay and that are not receiving payment under the PIP method may bill on an interim basis (60 days after an admission and at intervals of at least 60 days after the date of the first interim bill) and should include any high-cost outlier payment determined as of the last day for which the services have been billed.

IX. Monitoring

(If you choose to comment on issues in this section, please include the caption "MONITORING" at the beginning of your comments.)

In the August 30, 2002, final rule (67 FR 56014), we discussed our intent to develop a monitoring system that will assist us in evaluating the LTCH PPS. Specifically, we discussed the monitoring of the various policies that we believe would provide equitable payment for stays that reflect less than the full course of treatment and reduce the incentives for inappropriate admissions, transfers, or premature discharges of patients that are present in a discharge-based prospective payment system. We also stated our intent to collect and interpret data on changes in average lengths of stay under the LTCH PPS for specific LTC–DRGs and the impact of these changes on the Medicare program. We stated that if our data indicates that changes might be warranted, we may revisit these issues and consider proposing revisions to these policies in the future. To this end, we have designed system features utilizing MedPAR data that will enable CMS and the fiscal intermediary to track beneficiary movement to and from a LTCH and to and from another Medicare provider. As we discussed in the June 6, 2003, final rule (68 FR 34157), the MedPAC has endorsed this monitoring activity and is pursuing an independent research initiative that will evaluate all aspects of LTCHs, including the accuracy of data reporting, provision of equivalent services by other providers, growth in the number of LTCHs, and clinical outcomes. We are particularly concerned with the recent significant growth in the number of LTCHs. Since the implementation of LTCH PPS we have observed a growth of nearly 50 percent in the number of LTCHs, and that growth is almost exclusively in the number of LTCH that are hospitals within hospitals. We intend to focus our monitoring on this growth and the potential for gaming the IPPS by the co-located acute care hospital and the LTCH PPS by the LTC hospital within a hospital. Based on the outcome of that monitoring activity we may need to address either the criteria for qualifying for LTCH PPS payments for hospitals within hospitals, the payment rates for patients that are discharged from acute care hospitals and admitted to a co-located LTCH or other policy issues that may arise as a result of our monitoring activity.

Also, in the June 6, 2003, final rule (68 FR 34157), we explained that, given that the only unique requirement that distinguishes a LTCH from other acute care hospitals is an average inpatient length of stay of greater than 25 days, we continue to be concerned about the extent to which LTCH services and patients differ from those services and patients treated in other Medicare covered settings (for example, SNFs and IRFs) and how the LTCH PPS will affect the access, quality, and costs across the health care continuum. Thus, we will monitor trends in the supply and utilization of LTCHs and Medicare's costs in LTCHs relative to other Medicare providers. For example, we may conduct medical record reviews of Medicare patients to monitor changes in service use (for example, ventilator use) over a LTCH episode of care and to assess patterns in the average length of stay at the facility level.

We also are collecting data on patients staying for periods of 6 months or longer in LTCHs and may involve QIOs in evaluating whether or not such extensive stays may be indicative of LTCH patients who could be more appropriately served at a SNF.

Existing policy at § 412.509(c) provides that the LTCH must "furnish all necessary covered services to the Medicare beneficiary who is an inpatient of the hospital either directly or under arrangements." In this proposed rule we are proposing to expand our interrupted stay policy, at § 412.531, to include LTCH discharges and readmissions within a period of 3 days.

We believe that such behavior by certain LTCHs may constitute gaming of the Medicare system, circumventing existing Medicare policy, and generating unnecessary Medicare payments. Therefore, we are proposing an expansion of our interrupted stay policy at § 412.531 to address this situation. (See section IV.C.4.c. of this proposed rule for additional information regarding the proposed expansion of our interrupted stay policy.)

X. Collection of Information Requirements

(If you choose to comment on issues in this section, please include the caption "COLLECTION OF INFORMATION REQUIREMENTS" at the beginning of your comments.)

Under the Paperwork Reduction Act (PRA) of 1995, we are required to provide 60-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 PRA 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.

Therefore, we are soliciting public comments on each of these issues for the information collection requirements discussed below.

The following information collection requirements and associated burdens are subject to the PRA:

§ 412.23 Excluded Hospitals: Classifications

Section 412.23(e)(3) proposes revisions to the procedure for calculating the average length of stay for purposes of qualifying as a LTCH, so that the "days follow discharge." Therefore, the total number of inpatient days for Medicare patients under paragraph (e)(2)(i), and the total number of days for all patients (both Medicare and non-Medicare) under paragraph (e)(2)(ii), would be divided by the discharges for the hospital's most recent cost reporting period. If the days of a stay involve admission during one cost reporting period and discharge in a second consecutive cost reporting period, the total days of the stay are considered to have occurred in the cost reporting period during which the patient was discharged. Since this data was not captured on the cost reporting form, for cost reporting periods beginning on or after October 1, 2002, CMS retrieved data for the average length of stay calculation from MedPAR files for use by the fiscal intermediaries. If the days-follow-the-discharge policy is finalized, it may be possible to revise the cost reporting form and, thus, enable fiscal intermediaries to use the Medicare cost report for this calculation, as they did prior to the implementation of the LTCH PPS. We are presently analyzing whether use of the MedPAR for this purpose or revising the cost reporting form to capture all inpatient days for Medicare patients would be more appropriate. If we revert to using the cost report for this purpose, the task would require one calculation annually by fiscal intermediaries for each hospital: the division of the number of days by the number of discharges. We estimate that it would take approximately 5 minutes for each of the fiscal intermediaries to evaluate whether each of the 300 facilities meet the average length of stay requirement for a total one-time burden of 25 hours.

Section 412.23(e)(4)(ii) states that except as specified in paragraph (e)(4)(iii) of this section, a satellite facility (as defined in § 412.22(h)) or a remote location of a hospital (as defined in § 412.65(a)(2)) that voluntarily reorganizes as a separate Medicare participating hospital, with or without a concurrent change in ownership, and that seeks to qualify as a new long-term care hospital for Medicare payment purposes must demonstrate through documentation that it meets the average length of stay requirement specified under paragraphs (e)(2)(i) or (e)(2)(ii) of this section.

The burden associated with this requirement is the time required to maintain documentation to demonstrate that a satellite facility or a remote location of a hospital has an average length of stay as specified by this section. Since this requirement is a voluntary decision that is made by each facility, we do not know the number of facilities and remote locations that will seek to become new LTCHs. However, the information to be documented is currently being collected and maintained on each facility's cost report; therefore, this information collection requirement is currently approved under OMB control number 0938–0050.

Section 412.23(e)(4)(iii) states that satellite facilities and remote locations of hospitals that became subject to the provider-based status rules under § 412.65 as of July 1, 2003, that become separately participating hospitals, and that seek to qualify as long-term care hospitals for Medicare payment purposes may submit to the fiscal intermediary discharge data gathered during 5 months of the immediate 6 months preceding the facility's separation from the main hospital for calculation of the greater than 25-day average Medicare inpatient length of stay requirement specified under paragraph (e)(2) of this section.

The burden associated with this requirement is the time required of the satellite facilities and remote locations of hospitals that became subject to the provider-based status rules under as of July 1, 2003, to submit discharge data to the fiscal intermediary. We estimate that it will take approximately 5 minutes for each of the 300 facilities to submit the required information for a total one-time burden of 25 hours.

We have submitted a copy of this proposed rule to OMB for its review of the information collection requirements described above. These requirements are not effective until they have been approved by OMB.

If you comment on any of these information collection and record keeping requirements, please mail copies directly to the following:

Centers for Medicare & Medicaid Services, Office of Strategic Operations and Regulatory Affairs, Regulations Development and Issuances Group, Attn: Dawn Willinghan, CMS–1263–P, Room C5–14–03, 7500 Security Boulevard, Baltimore, MD 21244–1850; and

Office of Information and Regulatory Affairs, Office of Management and Budget, Room 10235, New Executive Office Building, Washington, DC 20503, Attn: Brenda Aguilar, CMS Desk Officer.

Comments submitted to OMB may also be emailed to the following address: email: *baguilar@omb.eop.gov;* or faxed to OMB at (202) 395–6974.

XI. Regulatory Impact Analysis

(If you choose to comment on issues in this section, please include the caption "REGULATORY IMPACT ANALYSIS" at the beginning of your comments.)

A. Introduction

We have examined the impact of this proposed rule as required by Executive

Order 12866 (September 1993, Regulatory Planning and Review), the Regulatory Flexibility Act (RFA) (September 16, 1980, Pub. L. 96–354), section 1102(b) of the Social Security Act (the Act), the Unfunded Mandates Reform Act of 1995 (UMRA) (Pub. L. 104–4), and Executive Order 13132.

1. Executive Order 12866

Executive Order 12866 (as amended by Executive Order 13258, which merely assigns responsibility of duties) 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 one year). In this proposed rule, we are using the most recent estimate of the LTCH PPS market basket and updated wage index values to estimate proposed payments for the 2005 LTCH PPS rate year. Based on the best available data for 211 LTCHs, we estimate that the proposed 2.9 percent increase in the standard Federal rate for the 2005 LTCH PPS rate year, in conjunction with the proposed decrease in the budget neutrality offset to account for the transition methodology (discussed in section IV.C.6. of this preamble), would result in an increase in payments from the 2004 LTCH PPS rate year of $118 million for the 211 LTCHs. (Section IV.C.6. of this preamble includes an estimate of Medicare program payments for LTCH services.) Because the combined distributional effects and costs to the Medicare program are greater than $100 million, this proposed rule is considered a major economic rule, as defined above.

2. Regulatory Flexibility Act (RFA)

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 government agencies. Most hospitals and most other providers and suppliers are small entities, either by nonprofit status or by having revenues of $26 million or less in any 1 year. For purposes of the RFA, all hospitals are considered small entities according to the Small Business Administration's latest size standards with total revenues of $26 million or less in any 1 year (for further information, see the Small Business Administration's regulation at 65 FR 69432, November 17, 2000). Because we lack data on individual hospital receipts, we cannot determine the number of small proprietary LTCHs. Therefore, we assume that all LTCHs are considered small entities for the purpose of the analysis that follows. Medicare fiscal intermediaries are not considered to be small entities. Individuals and States are not included in the definition of a small entity.

The provisions of this proposed rule represent a 5.4 percent increase in estimated payments in the 2005 LTCH PPS rate year (as shown in Table II below). We do not expect an incremental increase of 5.4 percent to the Medicare payment rates to have a significant effect on the overall revenues of most LTCHs. In addition, LTCHs also provide services to (and generate revenue from) patients other than Medicare beneficiaries. Accordingly, we certify that this proposed rule would not have a significant impact on a substantial number of small entities, in accordance with RFA.

3. Impact on Rural Hospitals

Section 1102(b) of the Social Security Act requires us to prepare a regulatory impact analysis if a proposed or final 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. As discussed in detail below, the rates and policies set forth in this proposed rule would not have a substantial impact on the 8 rural hospitals for which data were available that have fewer than 100 beds and that are located in rural areas.

4. Unfunded Mandates

Section 202 of the UMRA requires that agencies assess anticipated costs and benefits before issuing any rule that may result in expenditure in any one year by State, local, or tribal governments, in the aggregate, or by the private sector, of $110 million or more. This proposed rule would not mandate any requirements for State, local, or tribal governments, nor would it result in expenditures by the private sector of $110 million or more in any one year.

5. Federalism

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.

We have examined this proposed rule under the criteria set forth in Executive Order 13132 and have determined that, based on the 20 State and local LTCHs in our database, this proposed rule would not have any significant impact on the rights, roles, and responsibilities of State, local, or tribal governments or preempt State law.

B. Anticipated Effects of Proposed Payment Rate Changes

We discuss the impact of the proposed payment rate changes in this proposed rule below in terms of their fiscal impact on the Medicare budget and on LTCHs.

1. Budgetary Impact

Section 123(a)(1) of Medicare, Medicaid and State Child Health Insurance Program (SCHIP) Balanced Budget Refinement Act of 1999 (BBRA) (Pub. L. 106–113) requires us to set the proposed payment rates contained in this proposed rule such that total payments under the LTCH PPS are projected to equal the amount that would have been paid if this PPS had not been implemented. However, as discussed in greater detail in the August 30, 2002, final rule (67 FR 56033–56036), the FY 2003 standard Federal rate ($34,956.15) was calculated as though all LTCHs will be paid based on 100 percent of the standard Federal rate in FY 2003. As discussed in section IV.C.6. of this proposed rule, we would apply a proposed budget neutrality offset to payments to account for the monetary effect of the 5-year transition period and the policy to permit LTCHs to elect to be paid based on 100 percent of the proposed standard Federal rate rather than a blend of proposed Federal prospective payments and reasonable cost-based payments during the transition. The amount of the proposed offset is equal to 1 minus the ratio of the estimated reasonable cost-based payments that would have been made if the LTCH PPS had not been implemented, to the projected total Medicare program payments that would be made under the transition methodology and the option to elect payment based on 100 percent of the Federal prospective payment rate.

2. Impact on Providers

The basic methodology for determining a LTCH PPS payment is set forth in the regulations at § 412.515 through § 412.525. In addition to the basic LTC–DRG payment (standard Federal rate × LTC–DRG relative weight), we make adjustments for differences in area wage levels, cost-of-living adjustment for Alaska and Hawaii, and short-stay outliers. In addition, LTCHs may also receive high-cost outlier payments for those cases that qualify under the threshold established each rate year. Section 412.533 provides for a 5-year transition to fully prospective payments from payment based on reasonable cost-based methodology. During the 5-year transition period, payments to LTCHs are based on an increasing percentage of the LTCH PPS Federal rate and a decreasing percentage of payment based on reasonable cost-based methodology. Section 412.533(c) provides for a one-time opportunity for LTCHs to elect payments based on 100 percent of the LTCH PPS Federal rate.

In order to understand the impact of the changes to the LTCH PPS discussed in this proposed rule on different categories of LTCHs for the 2005 LTCH PPS rate year, it is necessary to estimate payments per discharge under the LTCH PPS rates and factors for the 2004 LTCH PPS rate year (*see* the June 6, 2003, final rule; 68 FR 34122–34190) and payments per discharge that would be made under the LTCH PPS rates and factors for the 2005 LTCH PPS rate year as discussed in the preamble of this proposed rule. We also evaluated the percent change in payments per discharge of estimated 2004 LTCH PPS rate year payments to estimated 2005 LTCH PPS rate year payments for each category of LTCHs.

Hospital groups were based on characteristics provided in the Online Survey Certification and Reporting (System) (OSCAR) data and FYs 1999 through 2001 cost report data. Hospitals with incomplete characteristics were grouped into the "unknown" category. Hospital groups include:

• Location: Large Urban/Other Urban/ Rural;
• Participation Date;
• Ownership Control;
• Census Region;
• Bed Size.

To estimate the impacts among the various categories of providers during the transition period, it is imperative that reasonable cost-based methodology payments and prospective payments contain similar inputs. More specifically, in the impact analysis showing the impact reflecting the applicable transition blend percentages of proposed prospective payments and reasonable cost-based methodology payments and the option to elect payment based on 100 percent of the proposed Federal rate (Table III below), we estimated payments only for those providers for whom we are able to calculate payments based on reasonable cost-based methodology. For example, if we did not have at least 2 years of historical cost data for a LTCH, we were unable to determine an update to the LTCH's target amount to estimate payment under reasonable cost-based methodology.

Using LTCH cases from the FY 2002 MedPAR file and cost data from FYs 1996 through 2001 to estimate payments under the current reasonable cost-based principles, we have both case-mix and cost data for 211 LTCHs. Thus, for the impact analyses reflecting the applicable transition blend percentages of proposed prospective payments and reasonable cost-based methodology payments and the option to elect payment based on 100 percent of the proposed Federal rate (*see* Table II below), we used data from 211 LTCHs. While currently there are approximately 300 LTCHs, the most recent growth is predominantly in for-profit LTCHs that provide respiratory and ventilator-dependent patient care. We believe that the discharges from the MedPAR data for the 211 LTCHs in our database provide sufficient representation in the LTC–DRGs containing discharges for patients who received respiratory and ventilator-dependent care. However, using cases from the FY 2002 MedPAR file, we had case-mix data for 272 LTCHs. Cost data to determine current payments under reasonable cost-based methodology payments are not needed to simulate payments based on 100 percent of the proposed Federal rate. Therefore, for the impact analyses reflecting fully phased-in prospective payments (see Table III below), we used data from 272 LTCHs.

These impacts reflect the estimated "losses" or "gains" among the various classifications of providers for the 2004 LTCH PPS rate year (July 1, 2003, through June 30, 2004) compared to the 2005 LTCH PPS rate year (July 1, 2004, through June 30, 2005). Prospective payments for the 2004 LTCH rate year were based on the standard Federal rate of $35,726.18 and the hospital's estimated case-mix based on FY 2002 claims data. Prospective payments for the 2005 LTCH PPS rate year were based on the proposed standard Federal rate of $36,762.24 and the same FY 2002 claims data.

3. Calculation of Prospective Payments

To estimate payments under the LTCH PPS, we simulated payments on a case-by-case basis by applying the existing payment policy for short-stay outliers (as described in section IV.C.4.b. of this proposed rule) and the existing adjustments for area wage differences (as described in section IV.C.1. of this proposed rule) and for the cost-of-living for Alaska and Hawaii (as described in section IV.C.2. of this proposed rule). Additional payments would also be made for high-cost outlier cases (as described in section IV.C.3. of this proposed rule). As noted in section IV.C.5. of this proposed rule, we are not making adjustments for rural location, geographic reclassification, indirect medical education costs, or a disproportionate share of low-income patients.

We adjusted for area wage differences for estimated 2004 LTCH PPS rate year payments by computing a weighted average of a LTCH's applicable wage index during the period from July 1, 2003, through June 30, 2004, because some providers may experience a change in the wage index phase-in percentage during that period. For cost reporting periods beginning on or after October 1, 2002, and before September 30, 2003, the labor portion of the Federal rate is adjusted by one-fifth of the applicable "LTCH PPS wage index" (that is, the FY 2004 IPPS wage index data without geographic reclassification, under sections 1886(d)(8) and (d)(10)) of the Act. For cost reporting periods beginning on or after October 1, 2003, and before September 30, 2004, the labor portion of the Federal rate is adjusted by two-fifths of the applicable LTCH PPS wage index. Therefore, a provider with a cost reporting period that began October 1, 2003, will have 3 months of payments under the one-fifth wage index value and 9 months of payment under the two-fifths wage index value. For this provider, we computed a blended wage index of 25 percent (3 months/12 months) of the one-fifth wage index value and 75 percent (9 months/12 months) of the two-fifths wage index value. Similarly, we adjusted for area wage differences for estimated 2005 LTCH PPS rate year payments by computing a weighted average of a LTCH's applicable wage index during the period from July 1, 2004, through June 30, 2005, because some providers may experience a change in the wage index phase-in percentage during that period. For cost reporting periods beginning on or after October 1, 2003, and before September 30, 2004, the labor portion of the Federal rate is adjusted by two-fifths of the applicable LTCH PPS wage index. For cost reporting periods beginning on or after October 1, 2004, and before September 30, 2005, the labor portion of the Federal rate is adjusted by three-fifths of the applicable LTCH PPS wage index. The applicable proposed LTCH

PPS wage index values for the 2005 LTCH PPS rate year are shown in Tables 1 and 2 of the Addendum to this proposed rule.

We also calculated payments using the applicable transition blend percentages. During the 2004 LTCH PPS rate year, based on the transition blend percentages set forth in § 412.533(a), some providers may experience a change in the transition blend percentage during the period from July 1, 2003, through June 30, 2004. That is, during the period from July 1, 2003, through June 30, 2004, a provider with a cost reporting period beginning on October 1, 2002 (which is paid under the 80/20 transition blend (80 percent of payments based on reasonable cost-based methodology and 20 percent of payments under the LTCH PPS), beginning October 1, 2002) had 3 months (July 1, 2003, through September 30, 2003) under the 80/20 blend and 9 months (October 1, 2003, through June 30, 2004) of payment under the 60/40-transition blend (60 percent of payments based on reasonable cost-based methodology and 40 percent of payments under the LTCH PPS). (The 60 percent/40 percent blend would continue until the provider's cost reporting period beginning on October 1, 2004.)

Similarly, during the 2005 LTCH PPS rate year, based on the transition blend percentages set forth in § 412.533(a), some providers may experience a change in the transition blend percentage during the period from July 1, 2004, through June 30, 2005. That is, during the period from July 1, 2004, through June 30, 2005, a provider with a cost reporting period beginning on October 1, 2003 (which is paid under the 60/40 transition blend), had 3 months (July 1, 2004, through September 30, 2004) under the 60/40 blend and 9 months (October 1, 2004, through June 30, 2005) of payment under the 40/60-transition blend (40 percent of payments based on reasonable cost-based methodology and 60 percent of payments under the LTCH PPS). (The 40 percent/60 percent blend would continue until the provider's cost reporting period beginning on October 1, 2005.)

In estimating blended transition payments, we estimated payments based on reasonable cost-based methodology in accordance with the methodology in section 1886(b) of the Act. We compared the estimated blended transition payment to the LTCH's estimated payment if it would elect payment based on 100 percent of the Federal rate. If we estimated that a LTCH would be paid more based on 100 percent of the Federal rate, we assumed that it would elect to bypass the transition methodology and to receive immediate prospective payments.

Then we applied the 6.0 percent budget neutrality reduction to payments to account for the effect of the 5-year transition methodology and election of payment based on 100 percent of the Federal rate on Medicare program payments established in the June 6, 2003, final rule (68 FR 34153) to each LTCH's estimated payments under the LTCH PPS for the 2004 LTCH PPS rate year. Similarly, we applied the proposed 3.0 percent budget neutrality reduction to payment to account for the effect of the 5-year transition methodology and election of payment based on 100 percent of the proposed Federal rate on Medicare program payments (*see* section IV.C.6. of this proposed rule) to each LTCH's estimated payments under the LTCH PPS for the 2005 LTCH PPS rate year. The impact based on our projection of whether a LTCH would be paid based on the transition blend methodology or would elect payment based on 100 percent of the Federal rate is shown below in Table II.

In Table III below, we also show the impact if the LTCH PPS were fully implemented; that is, as if there were an immediate transition to fully Federal prospective payments under the LTCH PPS for the 2004 LTCH PPS rate year and the 2005 LTCH PPS rate year. Accordingly, the 6.0 percent budget neutrality reduction to account for the 5-year transition methodology on LTCHs' Medicare program payments for the 2004 LTCH PPS rate year and the proposed 3.0 percent budget neutrality reduction to account for the 5-year transition methodology on LTCHs' Medicare program payments established for the 2005 LTCH PPS rate year were not applied to LTCHs' estimated payments under the PPS.

Tables II and III below illustrate the aggregate impact of the payment system among various classifications of LTCHs.

- The first column, LTCH Classification, identifies the type of LTCH.
- The second column lists the number of LTCHs of each classification type.
- The third column identifies the number of long-term care cases.
- The fourth column shows the estimated payment per discharge for the 2004 LTCH PPS rate year.
- The fifth column shows the estimated payment per discharge for the 2005 LTCH PPS rate year.
- The sixth column shows the percent change of 2004 LTCH PPS rate year compared to the 2005 LTCH PPS rate year.

TABLE II.—PROJECTED IMPACT REFLECTING APPLICABLE TRANSITION BLEND PERCENTAGES OF PROPOSED PROSPECTIVE PAYMENTS AND REASONABLE COST-BASED (TEFRA) PAYMENTS AND OPTION TO ELECT PAYMENT BASED ON 100 PERCENT OF THE FEDERAL RATE [1]

[2004 LTCH PPS Rate Year Payments Compared to Proposed 2005 LTCH Prospective Payment System Rate Year]

LTCH classification	Number of LTCHs	Number of LTCH cases	Average 2004 LTCH PPS rate year payment per case [2]	Average proposed 2005 LTCH prospective payment system rate year payment per case [3]	Percent change
All Providers	211	81,431	26,672.42	28,120.97	5.4
By location:					
Rural	8	2,476	21,055.14	22,167.94	5.3
Urban	203	78,955	26,848.58	28,307.66	5.4
Large	108	45,078	27,001.83	28,594.50	5.9
Other	95	33,877	26,644.66	27,925.98	4.8
By Participation Date:					
After October 1993	148	52,146	27,162.64	28,566.47	5.2
Before October 1983	16	7,985	20,472.43	22,910.93	11.9

TABLE II.—PROJECTED IMPACT REFLECTING APPLICABLE TRANSITION BLEND PERCENTAGES OF PROPOSED PROSPECTIVE PAYMENTS AND REASONABLE COST-BASED (TEFRA) PAYMENTS AND OPTION TO ELECT PAYMENT BASED ON 100 PERCENT OF THE FEDERAL RATE [1]—Continued

[2004 LTCH PPS Rate Year Payments Compared to Proposed 2005 LTCH Prospective Payment System Rate Year]

LTCH classification	Number of LTCHs	Number of LTCH cases	Average 2004 LTCH PPS rate year payment per case [2]	Average proposed 2005 LTCH prospective payment system rate year payment per case [3]	Percent change
October 1983—September 1993	45	20,824	27,561.37	28,734.45	4.3
Unknown	2	476	38,085.50	39,877.49	4.7
By Ownership Control:					
Voluntary	54	21,723	24,589.76	26,297.41	6.9
Proprietary	149	57,690	27,484.50	28,863.61	5.0
Government	8	2,018	25,876.08	26,520.63	2.5
By Census Region:					
New England	12	9,603	20,505.41	23,280	13.5
Middle Atlantic	11	4,253	27,252.20	28,405.28	4.2
South Atlantic	22	7,439	31,663.08	32,403.26	2.3
East North Central	40	10,781	29,094.38	30,485.73	4.8
East South Central	12	3,678	28,447.45	29,194.17	2.6
West North Central	14	3,653	27,235.20	29,108.58	6.9
West South Central	71	32,839	25,375.16	26,629.22	4.9
Mountain	17	3,610	27,193.75	28,510.11	4.8
Pacific	12	5,575	31,274.04	33,135.55	6.0
By Bed Size:					
Beds: 0–24	18	2,342	27,880.61	29,462.25	5.7
Beds: 25–49	97	24,920	27,199.38	28,666.55	5.4
Beds: 50–74	33	11,778	27,470.38	28,694.19	4.5
Beds: 75–124	32	13,657	27,374.27	28,554.40	4.3
Beds: 125–199	22	19,130	25,168.06	26,784.95	6.4
Beds: 200+	9	9,604	26,030.39	27,720.14	6.5
Unknown	0	0	0	0	0.0

[1] These calculations take into account that some providers may experience a change in the blend percentage changes during the 2004 and 2005 LTCH PPS rate years. For example, during the period of July 1, 2003, through June 30, 2004, a provider with a cost reporting period beginning October 1 would have 3 months (July 1, 2003, through September 30, 2003) of payments under the 80/20 blend and 9 months (October 1, 2003, through June 30, 2004) of payment under the 60/40 blend.

[2] Average payment per case for the 12-month period of July 1, 2003, through June 30, 2004.

[3] Average payment per case for the 12-month period of July 1, 2004, through June 30, 2005.

TABLE III.—PROJECTED IMPACT REFLECTING THE FULLY PHASED-IN PROPOSED PROSPECTIVE PAYMENTS

[2004 LTCH PPS Rate Year Payments Compared to Proposed 2005 LTCH Prospective Payment System Rate Year Payments]

LTCH classification	Number of LTCHs	Number of LTCH cases	Average 2004 LTCH PPS rate year payment per case [1]	Average proposed 2005 LTCH prospective payment system rate year payment per case [2]	Percent change
All Providers	272	96,104	26,955.97	27,499.11	2.0
By Location:					
Rural	20	7,114	21,361.01	21,774.57	1.9
Urban	252	88,990	27,403.24	27,956.74	2.0
Large	129	49,215	27,624.32	28,325.67	2.5
Other	123	39,775	27,129.69	27,500.24	1.4
By Participation Date:					
After October 1993	200	64,968	27,376.79	27,878.10	1.8
Before October 1983	17	8,038	21,542.46	23,435.89	8.8
October 1983—September 1993	48	21,622	27,615.27	27,797.35	0.7
Unknown	7	1,476	28,255.89	28,575.78	1.1
By Ownership Control:					
Voluntary	62	23,427	25,183.86	26,444.67	5.0
Proprietary	169	62,914	27,937.26	28,371.37	1.6
Government	20	6,998	25,497.90	24,712.39	–3.1
By Census Region:					
New England	14	9,835	21,856.33	24,089.72	10.2
Middle Atlantic	18	5,454	26,816.54	27,386.99	2.1
South Atlantic	27	8,028	32,480.27	31,363.84	–3.4

TABLE III.—PROJECTED IMPACT REFLECTING THE FULLY PHASED-IN PROPOSED PROSPECTIVE PAYMENTS—Continued

[2004 LTCH PPS Rate Year Payments Compared to Proposed 2005 LTCH Prospective Payment System Rate Year Payments]

LTCH classification	Number of LTCHs	Number of LTCH cases	Average 2004 LTCH PPS rate year payment per case [1]	Average proposed 2005 LTCH prospective payment system rate year payment per case [2]	Percent change
East North Central	53	13,354	29,429.54	29,810.95	1.3
East South Central	15	4,169	30,028.46	29,916.90	−0.4
West North Central	17	4,355	28,596.20	29,832.89	4.3
West South Central	94	40,775	25,234.32	25,781.35	2.2
Mountain	21	4,335	26,659.53	27,096.15	1.6
Pacific	13	5,799	31,278.68	31,601.47	1.0
By Bed Size:					
Beds: 0–24	23	3,105	27,760.33	28,478.85	2.6
Beds: 25–49	115	29,060	28,131.57	28,808.02	2.4
Beds: 50–74	33	11,778	27,599.01	28,175.22	2.1
Beds: 75–124	34	14,270	28,116.29	27,657.35	−1.6
Beds: 125–199	24	19,451	25,851.29	26,930.75	4.2
Beds: 200+	10	9,657	26,826.41	27,405.20	2.2
Unknown	33	8,783	22,623.37	23,020.17	1.8

[1] Average payment per case for the 12-month period of July 1, 2003, through June 30, 2004.
[2] Average payment per case for the 12-month period of July 1, 2004, through June 30, 2005.

4. Results

We have prepared the following summary of the impact (as shown in Table II) of the LTCH PPS set forth in this proposed rule.

a. Location

The majority of LTCHs are in urban areas. Approximately 4 percent of the LTCHs are identified as being located in a rural area, and approximately 3 percent of all LTCH cases are treated in these rural hospitals. Impact analysis in Table II shows that the percent change in estimated payments per discharge for the 2004 LTCH PPS rate year compared to the 2005 LTCH PPS rate year for rural LTCHs would be 5.3 percent, and would be 5.4 percent for urban LTCHs. Large urban LTCHs are projected to experience a 5.9 percent increase in payments per discharge from the 2004 LTCH PPS rate year compared to the 2005 LTCH PPS rate year, while other urban LTCHs projected to experience a 4.8 percent increase in payments per discharge from the 2004 LTCH PPS rate year compared to the 2005 LTCH PPS rate year. (*See* Table II.)

b. Participation Date

LTCHs are grouped by participation date into three categories: (1) Before October 1983; (2) between October 1983 and September 1993; and (3) after October 1993. We did not have sufficient OSCAR data on two LTCHs, which we labeled as an "Unknown" category. The majority, approximately 64 percent, of the LTCH cases are in hospitals that began participating after October 1993 and are projected to experience a 5.2 percent increase in payments per discharge from the 2004 LTCH PPS rate year compared to the 2005 LTCH PPS rate year. Approximately 10 percent of the cases are in LTCHs that began participating in Medicare before October 1983 and are projected to experience a 11.9 percent increase in payments per discharge from the 2004 LTCH PPS rate year compared to the 2005 LTCH PPS rate year. This relatively large increase in payments for the 2005 LTCH PPS rate year may be attributable to the fact that many of these LTCHs that began participating in Medicare prior to October 1983 are located in the New England census region (as explained below). In addition to the update in the standard Federal rate, these LTCHs are experiencing increases in payments because of an increasing wage index adjustment, which is two-fifths of the applicable LTCH PPS wage index for cost reporting periods beginning on or after October 1, 2003, and three-fifths of the applicable wage index for cost reporting periods beginning on or after October 1, 2004. In addition, as we discuss in section IV.C.6. of the preamble of this proposed rule, we are proposing a 3.0 percent budget neutrality reduction (0.970) to payments in the 2005 LTCH PPS rate year to account for the effect of the 5-year transition methodology. The proposed 0.970 transition period budget neutrality factor for the 2005 LTCH PPS rate year is 3 percentage points lower than the transition period budget neutrality factor for the 2004 LTCH PPS rate year (0.940). This smaller budget neutrality offset contributes to greater LTCH payment increases between the 2004 and 2005 LTCH PPS rate years compared to the increases seen between FY 2003 and the 2004 LTCH PPS rate year. We do not expect to see these large payment per discharge increases in future years as the majority of LTCHs will have transitioned fully to the LTCH PPS and, therefore, the transition period budget neutrality factor should remain more stable.

LTCHs that began participating between October 1983 and September 1993 are projected to experience a 4.3 percent increase in payments per discharge from the 2004 LTCH PPS rate year compared to the 2005 LTCH PPS rate year. (*See* Table II.)

c. Ownership Control

LTCHs are grouped into three categories based on ownership control type—(1) voluntary; (2) proprietary; and (3) government.

Approximately 4 percent of LTCHs are government run and we expect that they would "gain" from the changes based on our projection that they would experience a 2.5 percent increase in payments per discharge from the 2004 LTCH PPS rate year compared to the 2005 LTCH PPS rate year. Voluntary and proprietary LTCHs are projected to experience a 6.9 percent and 5.0 percent increase in payments per discharge from the 2004 LTCH PPS rate year compared to the 2005 LTCH PPS rate year, respectively. (*See* Table II.)

d. Census Region

LTCHs located in all regions are expected to experience an increase in payments per discharge from the 2004 LTCH PPS rate year compared to the 2005 LTCH PPS rate year. Specifically, of the nine census regions, we expect that LTCHs in the New England region would experience the largest percent increase in payments per discharge from the 2004 LTCH PPS rate year compared to the 2005 LTCH PPS rate year (13.5 percent). As explained above, under section B.4.b. (Participation Date), this relatively large increase in payments for the 2005 LTCH PPS rate year may be attributable to the update in the standard Federal rate, and the fact that these LTCHs are experiencing increases in payments because of an increasing wage index adjustment, which is two-fifths of the applicable LTCH PPS wage index for cost reporting periods beginning on or after October 1, 2003, and three-fifths of the applicable wage index for cost reporting periods beginning on or after October 1, 2004. In addition, as we discuss in section IV.C.6. of the preamble of this proposed rule, we are proposing a 3.0 percent budget neutrality reduction (0.970) to payments in the 2005 LTCH PPS rate year to account for the effect of the 5-year transition methodology. The proposed 0.970 transition period budget neutrality factor for the 2005 LTCH PPS rate year is 3 percentage points lower than the transition period budget neutrality factor for the 2004 LTCH PPS rate year (0.940). This smaller budget neutrality offset contributes to greater LTCH payment increases between the 2004 and 2005 LTCH PPS rate years compared to the increases seen between FY 2003 and the 2004 LTCH PPS rate year. We do not expect to see these large payment per discharge increases in future years as the majority of LTCHs will have transitioned fully to the LTCH PPS and, therefore, the transition period budget neutrality factor should remain more stable.

We expect LTCHs in the South Atlantic region would experience the smallest percent increase in payments per discharge from the 2004 LTCH PPS rate year compared to the 2005 LTCH PPS rate year (2.3 percent). (*See* Table II.)

e. Bed Size

LTCHs were grouped into six categories based on bed size—0–24 beds, 25–49 beds, 50–74 beds, 75–124 beds, 125–199 beds, and 200+ beds.

The percent increase in payments per discharge from the 2004 LTCH PPS rate year compared to the 2005 LTCH PPS rate year are projected to increase for all bed size categories.

Most LTCHs were in bed size categories where the percent increase in payments per discharge from the 2004 LTCH PPS rate year compared to the 2005 LTCH PPS rate year is estimated to be greater than 5.4 percent. LTCHs with 200 or more beds have the highest estimated percent change in payments per discharge from the 2004 LTCH PPS rate year compared to the 2005 LTCH PPS rate year (6.5 percent), while LTCHs with 75–124 beds have the lowest projected increase in the percent change in payments per discharge from the 2004 LTCH PPS rate year compared to the 2005 LTCH PPS rate year (4.3 percent). (*See* Table II.)

5. Effect on the Medicare Program

Based on actuarial projections, we estimate that Medicare spending (total Medicare program payments) for LTCH services over the next 5 years will be as follows:

LTCH PPS rate year	Estimated payments ($ in billions)
2005	$2.33
2006	2.48
2007	2.64
2008	2.79
2009	2.96

These estimates are based on the current estimate of increase in the excluded hospital with capital market basket of 2.9 percent for the 2005 LTCH PPS rate year, 3.2 percent for the 2006 LTCH PPS rate year, 3.1 percent for the 2007 LTCH PPS rate year, 3.0 percent for the 2008 LTCH PPS rate year, and 3.2 percent for the 2009 LTCH PPS rate year. We estimate that there would be an increase in Medicare beneficiary enrollment of 2.1 percent in the 2005 LTCH PPS rate year, 2.4 percent in the 2006 LTCH PPS rate year, 2.1 percent in 2007 LTCH PPS rate year, 2.0 percent in the 2008 LTCH PPS rate year, 2.1 percent in the 2009 LTCH PPS rate year, and an estimated increase in the total number of LTCHs.

Consistent with the statutory requirement for budget neutrality, we intend for estimated aggregate payments under the LTCH PPS in FY 2003 to equal the estimated aggregate payments that will be made if the LTCH PPS were not implemented. Our methodology for estimating payments for purposes of the budget neutrality calculations uses the best available data and necessarily reflects assumptions. As we collect data from LTCHs, we will monitor payments and evaluate the ultimate accuracy of the assumptions used to calculate the budget neutrality calculations (that is, inflation factors, intensity of services provided, or behavioral response to the implementation of the LTCH PPS).

Section 123 of BBRA and section 307 of BIPA provide the Secretary with extremely broad authority in developing the LTCH PPS, including the authority for appropriate adjustments. In accordance with this broad authority, we may discuss in a future proposed rule a possible one-time prospective adjustment to the LTCH PPS rates to maintain budget neutrality so that the effect of the difference between actual payments and estimated payments for the first year of LTCH PPS is not perpetuated in the PPS rates for future years. Because the LTCH PPS was only recently implemented, we do not yet have sufficient complete data to determine whether such an adjustment is warranted.

6. Effect on Medicare Beneficiaries

Under the LTCH PPS, hospitals receive payment based on the average resources consumed by patients for each diagnosis. We do not expect any changes in the quality of care or access to services for Medicare beneficiaries under the LTCH PPS, but we expect that paying prospectively for LTCH services will enhance the efficiency of the Medicare program.

C. Impact of Proposed Policy Changes

1. Proposed Requirements for Satellite Facilities and Remote Locations of Hospitals To Qualify as Long-Term Care Hospitals

Under section I.B.3. of the preamble of this proposed rule, we discuss our proposal to clarify the procedures under which a satellite facility or a remote location of a hospital must meet the statutory and regulatory requirements to qualify as a distinct LTCH. Specifically, we are proposing to present in regulations the procedure for determining the period from which the fiscal intermediaries will use discharge data in calculating the average Medicare inpatient length of stay requirement for a new, separately participating hospital that seeks classification as a LTCH.

In this proposed rule, we are restating in regulations our existing policy that a satellite facility or remote location of a hospital (except for those that are subject to the location requirement under the provider-based rules at § 413.65) that voluntarily reorganizes itself as a separate hospital and meets the provider agreement requirements of 42 CFR part 489 and the Medicare conditions of participation under 42 CFR part 482 would have its average

Medicare inpatient length of stay calculated based on discharges that occur after the satellite facility or remote location is established as a separate participating hospital.

The policy that we are proposing to incorporate in the regulations is already in existence. Therefore, complying with the proposed regulation amendments would pose no additional burden on LTCHs.

We are proposing to incorporate in regulations that govern requirements for LTCHs a provision that the average Medicare inpatient length of stay for satellite facilities and remote locations of hospitals that became subject to the revised location-based provider-based requirements on July 1, 2003, that reorganize as separate participating hospitals, and that seek classification as LTCHs, would continue to be based on discharge data during the 5 months of the immediate 6 months preceding the facility's separation from the main hospital. This proposed amendment to the regulation text would incorporate procedures that are already established under the regulations governing provider-based entities, but whose implementation applicable to LTCH classifications were not expounded in the specific regulations governing LTCHs. The proposed regulations apply only to those facilities or locations that became subject to the revised provider-based location rules on July 1, 2003, and that seek classification as LTCHs for Medicare payment purposes. Therefore, we are unable to quantify how many or when a facility or location would seek LTCH classification.

These proposed amendments to the regulations would not impose any additional requirements on providers. The data used in the calculation of the average length of stay are already being collected. The existing procedure for application of the discharge data in calculating the average length of stay in both circumstances is consistent with existing statutory and regulatory requirements.

2. Proposed Change in Policy on Interruption of a Stay in a LTCH

Under section IV.C.4.c. of the preamble of this proposed rule, we are proposing to expand the definition of an interruption of a stay to include an interruption in which the patient is discharged from the LTCH, and returns to the LTCH within 3 days of the original discharge. We have found, through monitoring activities and other sources, that certain LTCHs are discharging patients during the course of their treatment for the sole purpose of the patient receiving specific tests or procedures and then readmitting the patient following the administration of the test or procedure. We believe these situations are resulting in improper increases in Medicare costs through separate billings for services that are already included in the LTC–DRG payment made to the LTCH. The proposed regulation change would prevent these inappropriate Medicare payments. However, we do not have sufficient data at this time to quantify either the number of providers that would be affected by the proposed change nor the savings to the Medicare program.

3. Proposed Change in Procedure for Counting Covered and Noncovered Days in a Stay That Crosses Two Consecutive Cost Reporting Periods

Under section I.B.2. of the preamble to this proposed rule, we are proposing to specify the procedure for calculating a hospital's inpatient average length of stay for purposes of classification as a LTCH when covered and noncovered days of the stay involve admission in one cost reporting period and discharge in a second consecutive cost reporting period. Under this circumstance, we are proposing to count the total number of days of the stay in the cost reporting period during which the inpatient was discharged. We are proposing this revised procedure to make it consistent with reporting and payment procedures already in place for discharge-based payment systems that link patient days to discharges.

The proposed regulation imposes no additional requirements on providers. The discharge data are already being collected and the proposed revision would merely change the procedure for reporting it.

D. Executive Order 12866

In accordance with the provisions of Executive Order 12866, this proposed rule was reviewed by the Office of Management and Budget.

List of Subjects in 42 CFR Part 412

Administrative practice and procedure, Health facilities, Medicare, Puerto Rico, Reporting and recordkeeping requirements.

In accordance with the discussion in this preamble, the Centers for Medicare & Medicaid Services is proposing to amend 42 CFR chapter IV, part 412, as set forth below:

PART 412—PROSPECTIVE PAYMENT SYSTEMS FOR INPATIENT HOSPITAL SERVICES

1. The authority citation for part 412 continues to read as follows:

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

2. Section 412.23 is amended by—

A. Revising paragraphs (e)(3)(i) and (e)(3)(ii).

B. In paragraph (e)(3)(iii), removing the phrase "required Medicare average length of stay," and adding in its place the phrase "required average length of stay,".

C. Revising paragraph (e)(4).

The revisions and additions read as follows:

§ 412.23 Excluded hospitals: classifications.

* * * * *

(e) *Long-term care hospitals.* * * *

(3) *Calculation of average length of stay.* (i) Subject to the provisions of paragraphs (e)(3)(ii) and (e)(3)(iii) of this section, the average Medicare inpatient length of stay specified under paragraph (e)(2)(i) of this section is calculated by dividing the total number of covered and noncovered days of stay of Medicare inpatients (less leave or pass days) by the number of total Medicare discharges for the hospital's most recent complete cost reporting period. The average inpatient length of stay specified under paragraph (e)(2)(ii) of this section is calculated by dividing the total number of days for all patients, including both Medicare and non-Medicare inpatients (less leave or pass days) by the number of total discharges for the hospital's most recent complete cost reporting period. If the days of a stay of an inpatient involve an admission during one cost reporting period and a discharge in a second consecutive cost reporting period, the total number of days of the stay are considered to have occurred in the cost reporting period during which the inpatient was discharged.

(ii) If a change in a hospital's average length of stay specified under paragraph (e)(2)(i) or paragraph (e)(2)(ii) of this section is indicated, the calculation is made by the same method for the period of at least 5 months of the immediately preceding 6-month period.

* * * * *

(4) *Rules applicable to new long-term care hospitals*—(i) *Definition.* For purposes of payment under the long-term care hospital prospective payment system under subpart O of this part, a new long-term care hospital is a provider of inpatient hospital services that meets the qualifying criteria in paragraphs (e)(1) and (e)(2) of this section and, under present or previous ownership (or both), its first cost reporting period as a LTCH begins on or after October 1, 2002.

(ii) *Satellite facilities and remote locations of hospitals seeking to become new long-term care hospitals.* Except as specified in paragraph (e)(4)(iii) of this section, a satellite facility (as defined in § 412.22(h)) or a remote location of a hospital (as defined in § 413.65(a)(2)) that voluntarily reorganizes as a separate Medicare participating hospital, with or without a concurrent change in ownership, and that seeks to qualify as a new long-term care hospital for Medicare payment purposes must demonstrate through documentation that it meets the average length of stay requirement as specified under paragraphs (e)(2)(i) or (e)(2)(ii) of this section based on discharges that occur on or after the effective date of its participation under Medicare as a separate hospital.

(iii) *Provider-based facility or organization identified as a satellite facility and remote location of a hospital prior to July 1, 2003.* Satellite facilities and remote locations of hospitals that became subject to the provider-based status rules under § 413.65 as of July 1, 2003, that become separately participating hospitals, and that seek to qualify as long-term care hospitals for Medicare payment purposes may submit to the fiscal intermediary discharge data gathered during 5 months of the immediate 6 months preceding the facility's separation from the main hospital for calculation of the average length of stay specified under paragraph (e)(2)(i) or paragraph (e)(2)(ii) of this section.

* * * * *

3. Section 412.531 is amended by—

A. Revising paragraph (a).

B. Revising paragraph (b)(1).

The revisions and additions read as follows:

§ 412.531 Special payment provisions when an interruption of a stay occurs in a long-term care hospital.

(a) *Interruption of a stay defined.* "Interruption of a stay" means—

(1) A stay at a long-term care hospital during which a Medicare inpatient is discharged from the long-term care hospital and returns to the same long-term care hospital within 3 consecutive days under conditions other than those specified in paragraph (a)(2)(i) through (a)(2)(iii) of this section. The duration of the interruption of the stay of 3 consecutive days begins with the date of discharge from the long-term care hospital and ends at midnight of the third day.

(2) A stay in a long-term care hospital during which a Medicare inpatient is discharged from the long-term care hospital to an acute care hospital, an IRF, or a SNF and returns to the same long-term care hospital within the applicable fixed day period specified in paragraphs (a)(2)(i) through (a)(2)(iii) of this section.

(i) For a discharge to an acute care hospital, the applicable fixed day period is 9 days. The counting of the days begins on the date of discharge from the long-term care hospital and ends on the 9th date after the discharge.

(ii) For a discharge to an IRF, the applicable fixed day period is 27 days. The counting of the days begins on the day of discharge from the long-term care hospital and ends on the 27th day after discharge.

(iii) For a discharge to a SNF, the applicable fixed day period is 45 days. The counting of the days begins on the day of discharge from the long-term care hospital and ends on the 45th day after the discharge.

(b) *Methods of determining payments.* (1) In determining payments, the following provisions apply:

(i) For purposes of determining a Federal prospective payment, any stay in a long-term care hospital that involves an interruption of the stay will be paid as a single discharge from the long-term care hospital. CMS will make only one LTC–DRG payment for all portions of a long-term care stay that involves an interruption of stay.

(ii) Except as specified in paragraph (b)(1)(iii) of this section, the number of days that a beneficiary spends away from the long-term care hospital during a 3-day interruption of stay, as defined in paragraph (a)(1) of this section, is not included in determining the length of stay of the patient at the long-term care hospital when there is no medical care or treatment that is considered a covered service delivered to the beneficiary.

(iii) The number of days that a beneficiary spends away from a long-term care hospital during an interruption of stay defined under paragraph (a)(1) of this section during which the beneficiary receives medical care or treatment that is considered a covered service and returns to the long-term care hospital within 3 consecutive days or less after a discharge is counted in determining the length of stay of the patient at the long-term care hospital.

(iv) In accordance with § 412.509, CMS will not make any payment other than the LTC–DRG payment as specified under paragraph (b)(1)(i) of this section for covered services that should have been furnished by the long-term care hospital during a 3-day interruption of stay, as defined in paragraph (a)(1) of this section.

(v) In accordance with § 412.513(b), payment will be based on the patient's LTC–DRG that would be determined by the principal diagnosis, which is the condition established after study to be chiefly responsible for occasioning the first admission of the patient to the hospital for care.

* * * * *

§ 412.532 [Amended]

4. In § 412.532(i), the reference "paragraphs (h)(1) through (h)(4) of this section" is revised to read "§ 412.22(h)(1) through (h)(4)".

(Catalog of Federal Domestic Assistance Program No. 93.773, Medicare—Hospital Insurance.)

Dated: December 14, 2003.

Thomas A. Scully,

Administrator, Centers for Medicare & Medicaid Services.

Dated: January 21, 2004.

Tommy G. Thompson,

Secretary.

Addendum

This addendum contains the tables referred to throughout the preamble to this proposed rule. The tables presented below are as follows:

Table 1.—Long-Term Care Hospital Proposed Wage Index for Urban Areas for Discharges Occurring from July 1, 2004 through June 30, 2005;

Table 2.—Long-Term Care Hospital Proposed Wage Index for Rural Areas for Discharges Occurring from July 1, 2004 through June 30, 2005;

Table 3.—FY 2004 LTC–DRG Relative Weights, Geometric Mean Length of Stay, and Short-Stay Five-Sixths Average Length of Stay for Discharges Occurring from July 1, 2004 through September 30, 2004.

(**Note:** This is the same information provided in Table 11 of the August 1, 2003, IPPS final rule (68 FR 45650–45658), which has been reprinted here for convenience.)

TABLE 1.—LONG-TERM CARE HOSPITAL PROPOSED WAGE INDEX FOR URBAN AREAS FOR DISCHARGES OCCURRING FROM JULY 1, 2004 THROUGH JUNE 30, 2005

MSA	Urban area (constituent counties)	Full wage index [1]	1/5th wage index [2]	2/5ths wage index [3]	3/5ths wage index [4]
0040	Abilene, TX	0.7627	0.9525	0.9051	0.8576
	Taylor, TX				
0060	Aguadilla, PR	0.4306	0.8861	0.7722	0.6584
	Aguada, PR				
	Aguadilla, PR				
	Moca, PR				
0080	Akron, OH	0.9246	0.9849	0.9698	0.9548
	Portage, OH				
	Summit, OH				
0120	Albany, GA	1.0863	1.0173	1.0345	1.0518
	Dougherty, GA				
	Lee, GA				
0160	Albany-Schenectady-Troy, NY	0.8489	0.9698	0.9396	0.9093
	Albany, NY				
	Montgomery, NY				
	Rensselaer, NY				
	Saratoga, NY				
	Schenectady, NY				
	Schoharie, NY				
0200	Albuquerque, NM	0.9300	0.9860	0.9720	0.9580
	Bernalillo, NM				
	Sandoval, NM				
	Valencia, NM				
0220	Alexandria, LA	0.8019	0.9604	0.9208	0.8811
	Rapides, LA				
0240	Allentown-Bethlehem-Easton, PA	0.9721	0.9944	0.9888	0.9833
	Carbon, PA				
	Lehigh, PA				
	Northampton, PA				
0280	Altoona, PA	0.8806	0.9761	0.9522	0.9284
	Blair, PA				
0320	Amarillo, TX	0.8986	0.9797	0.9594	0.9392
	Potter, TX				
	Randall, TX				
0380	Anchorage, AK	1.2216	1.0443	1.0886	1.1330
	Anchorage, AK				
0440	Ann Arbor, MI	1.1074	1.0215	1.0430	1.0644
	Lenawee, MI				
	Livingston, MI				
	Washtenaw, MI				
0450	Anniston, AL	0.8090	0.9618	0.9236	0.8854
	Calhoun, AL				
0460	Appleton-Oshkosh-Neenah, WI	0.9035	0.9807	0.9614	0.9421
	Calumet, WI				
	Outagamie, WI				
	Winnebago, WI				
0470	Arecibo, PR	0.4155	0.8831	0.7662	0.6493
	Arecibo, PR				
	Camuy, PR				
	Hatillo, PR				
0480	Asheville, NC	0.9720	0.9944	0.9888	0.9832
	Buncombe, NC				
	Madison, NC				
0500	Athens, GA	0.9818	0.9964	0.9927	0.9891
	Clarke, GA				
	Madison, GA				
	Oconee, GA				
0520	Atlanta, GA	1.0130	1.0026	1.0052	1.0078
	Barrow, GA				
	Bartow, GA				
	Carroll, GA				
	Cherokee, GA				
	Clayton, GA				
	Cobb, GA				
	Coweta, GA				
	DeKalb, GA				
	Douglas, GA				
	Fayette, GA				
	Forsyth, GA				
	Fulton, GA				

TABLE 1.—LONG-TERM CARE HOSPITAL PROPOSED WAGE INDEX FOR URBAN AREAS FOR DISCHARGES OCCURRING FROM JULY 1, 2004 THROUGH JUNE 30, 2005—Continued

MSA	Urban area (constituent counties)	Full wage index [1]	1/5th wage index [2]	2/5ths wage index [3]	3/5ths wage index [4]
	Gwinnett, GA				
	Henry, GA				
	Newton, GA				
	Paulding, GA				
	Pickens, GA				
	Rockdale, GA				
	Spalding, GA				
	Walton, GA				
0560	Atlantic-Cape May, NJ	1.0795	1.0159	1.0318	1.0477
	Atlantic, NJ				
	Cape May, NJ				
0580	Auburn-Opelika, AL	0.8494	0.9699	0.9398	0.9096
	Lee, AL				
0600	Augusta-Aiken, GA–SC	0.9625	0.9925	0.9850	0.9775
	Columbia, GA				
	McDuffie, GA				
	Richmond, GA				
	Aiken, SC				
	Edgefield, SC				
0640	Austin-San Marcos, TX	0.9609	0.9922	0.9844	0.9765
	Bastrop, TX				
	Caldwell, TX				
	Hays, TX				
	Travis, TX				
	Williamson, TX				
0680	Bakersfield, CA	0.9810	0.9962	0.9924	0.9886
	Kern, CA				
0720	Baltimore, MD	0.9919	0.9984	0.9968	0.9951
	Anne Arundel, MD				
	Baltimore, MD				
	Baltimore City, MD				
	Carroll, MD				
	Harford, MD				
	Howard, MD				
	Queen Anne's, MD				
0733	Bangor, ME	0.9904	0.9981	0.9962	0.9942
	Penobscot, ME				
0743	Barnstable-Yarmouth, MA	1.2956	1.0591	1.1182	1.1774
	Barnstable, MA				
0760	Baton Rouge, LA	0.8406	0.9681	0.9362	0.9044
	Ascension, LA				
	East Baton Rouge, LA				
	Livingston, LA				
	West Baton Rouge, LA				
0840	Beaumont-Port Arthur, TX	0.8424	0.9685	0.9370	0.9054
	Hardin, TX				
	Jefferson, TX				
	Orange, TX				
0860	Bellingham, WA	1.1757	1.0351	1.0703	1.1054
	Whatcom, WA				
0870	Benton Harbor, MI	0.8871	0.9774	0.9548	0.9323
	Berrien, MI				
0875	Bergen-Passaic, NJ	1.1692	1.0338	1.0677	1.1015
	Bergen, NJ				
	Passaic, NJ				
0880	Billings, MT	0.8961	0.9792	0.9584	0.9377
	Yellowstone, MT				
0920	Biloxi-Gulfport-Pascagoula, MS	0.9029	0.9806	0.9612	0.9417
	Hancock, MS				
	Harrison, MS				
	Jackson, MS				
0960	Binghamton, NY	0.8428	0.9686	0.9371	0.9057
	Broome, NY				
	Tioga, NY				
1000	Birmingham, AL	0.9212	0.9842	0.9685	0.9527
	Blount, AL				
	Jefferson, AL				
	St. Clair, AL				
	Shelby, AL				
1010	Bismarck, ND	0.7965	0.9593	0.9186	0.8779

TABLE 1.—LONG-TERM CARE HOSPITAL PROPOSED WAGE INDEX FOR URBAN AREAS FOR DISCHARGES OCCURRING FROM JULY 1, 2004 THROUGH JUNE 30, 2005—Continued

MSA	Urban area (constituent counties)	Full wage index [1]	1/5th wage index [2]	2/5ths wage index [3]	3/5ths wage index [4]
	Burleigh, ND				
	Morton, ND				
1020	Bloomington, IN	0.8662	0.9732	0.9465	0.9197
	Monroe, IN				
1040	Bloomington-Normal, IL	0.8832	0.9766	0.9533	0.9299
	McLean, IL				
1080	Boise City, ID	0.9209	0.9842	0.9684	0.9525
	Ada, ID				
	Canyon, ID				
1123	Boston-Worcester-Lawrence-Lowell-Brockton, MA–NH (NH Hospitals).	1.1233	1.0247	1.0493	1.0740
	Bristol, MA				
	Essex, MA				
	Middlesex, MA				
	Norfolk, MA				
	Plymouth, MA				
	Suffolk, MA				
	Worcester, MA				
	Hillsborough, NH				
	Merrimack, NH				
	Rockingham, NH				
	Strafford, NH				
1125	Boulder-Longmont, CO	1.0049	1.0010	1.0020	1.0029
	Boulder, CO				
1145	Brazoria, TX	0.8137	0.9627	0.9255	0.8882
	Brazoria, TX				
1150	Bremerton, WA	1.0580	1.0116	1.0232	1.0348
	Kitsap, WA				
1240	Brownsville-Harlingen-San Benito, TX	1.0303	1.0061	1.0121	1.0182
	Cameron, TX				
1260	Bryan-College Station, TX	0.9019	0.9804	0.9608	0.9411
	Brazos, TX				
1280	Buffalo-Niagara Falls, NY	0.9604	0.9921	0.9842	0.9762
	Erie, NY				
	Niagara, NY				
1303	Burlington, VT	0.9704	0.9941	0.9882	0.9822
	Chittenden, VT				
	Franklin, VT				
	Grand Isle, VT				
1310	Caguas, PR	0.4158	0.8832	0.7663	0.6495
	Caguas, PR				
	Cayey, PR				
	Cidra, PR				
	Gurabo, PR				
	San Lorenzo, PR				
1320	Canton-Massillon, OH	0.9071	0.9814	0.9628	0.9443
	Carroll, OH				
	Stark, OH				
1350	Casper, WY	0.9095	0.9819	0.9638	0.9457
	Natrona, WY				
1360	Cedar Rapids, IA	0.8874	0.9775	0.9550	0.9324
	Linn, IA				
1400	Champaign-Urbana, IL	0.9907	0.9981	0.9963	0.9944
	Champaign, IL				
1440	Charleston-North Charleston, SC	0.9332	0.9866	0.9733	0.9599
	Berkeley, SC				
	Charleston, SC				
	Dorchester, SC				
1480	Charleston, WV	0.8880	0.9776	0.9552	0.9328
	Kanawha, WV				
	Putnam, WV				
1520	Charlotte-Gastonia-Rock Hill, NC–SC	0.9760	0.9952	0.9904	0.9856
	Cabarrus, NC				
	Gaston, NC				
	Lincoln, NC				
	Mecklenburg, NC				
	Rowan, NC				
	Stanly, NC				
	Union, NC				
	York, SC				

TABLE 1.—LONG-TERM CARE HOSPITAL PROPOSED WAGE INDEX FOR URBAN AREAS FOR DISCHARGES OCCURRING FROM JULY 1, 2004 THROUGH JUNE 30, 2005—Continued

MSA	Urban area (constituent counties)	Full wage index [1]	1/5th wage index [2]	2/5ths wage index [3]	3/5ths wage index [4]
1540	Charlottesville, VA	1.0025	1.0005	1.0010	1.0015
	Albemarle, VA				
	Charlottesville City, VA				
	Fluvanna, VA				
	Greene, VA				
1560	Chattanooga, TN–GA	0.9086	0.9817	0.9634	0.9452
	Catoosa, GA				
	Dade, GA				
	Walker, GA				
	Hamilton, TN				
	Marion, TN				
1580	Cheyenne, WY	0.8796	0.9759	0.9518	0.9278
	Laramie, WY				
1600	Chicago, IL	1.0892	1 0178	1.0357	1.0535
	Cook, IL				
	DeKalb, IL				
	DuPage, IL				
	Grundy, IL				
	Kane, IL				
	Kendall, IL				
	Lake, IL				
	McHenry, IL				
	Will, IL				
1620	Chico-Paradise, CA	1.0193	1.0039	1.0077	1.0116
	Butte, CA				
1640	Cincinnati, OH–KY–IN	0.9413	0.9883	0.9765	0.9648
	Dearborn, IN				
	Ohio, IN				
	Boone, KY				
	Campbell, KY				
	Gallatin, KY				
	Grant, KY				
	Kenton, KY				
	Pendleton, KY				
	Brown, OH				
	Clermont, OH				
	Hamilton, OH				
	Warren, OH				
1660	Clarksville-Hopkinsville, TN–KY	0.8244	0.9649	0.9298	0.8946
	Christian, KY				
	Montgomery, TN				
1680	Cleveland-Lorain-Elyria, OH	0.9671	0.9934	0.9868	0.9803
	Ashtabula, OH				
	Cuyahoga, OH				
	Geauga, OH				
	Lake, OH				
	Lorain, OH				
	Medina, OH				
1720	Colorado Springs, CO	0.9833	0.9967	0.9933	0.9900
	El Paso, CO				
1740	Columbia, MO	0.8695	0.9739	0.9478	0.9217
	Boone, MO				
1760	Columbia, SC	0.8902	0.9780	0.9561	0.9341
	Lexington, SC				
	Richland, SC				
1800	Columbus, GA–AL	0.8694	0.9739	0.9478	0.9216
	Russell, AL				
	Chattahoochee, GA				
	Harris, GA				
	Muscogee, GA				
1840	Columbus, OH	0.9648	0.9930	0.9859	0.9789
	Delaware, OH				
	Fairfield, OH				
	Franklin, OH				
	Licking, OH				
	Madison, OH				
	Pickaway, OH				
1880	Corpus Christi, TX	0.8521	0.9704	0.9408	0.9113
	Nueces, TX				
	San Patricio, TX				

TABLE 1.—LONG-TERM CARE HOSPITAL PROPOSED WAGE INDEX FOR URBAN AREAS FOR DISCHARGES OCCURRING FROM JULY 1, 2004 THROUGH JUNE 30, 2005—Continued

MSA	Urban area (constituent counties)	Full wage index [1]	1/5th wage index [2]	2/5ths wage index [3]	3/5ths wage index [4]
1890	Corvallis, OR	1.1516	1.0303	1.0606	1.0910
	Benton, OR				
1900	Cumberland, MD–WV (WV Hospital)	0.8200	0.9640	0.9280	0.8920
	Allegany, MD				
	Mineral, WV				
1920	Dallas, TX	0.9974	0.9995	0.9990	0.9984
	Collin, TX				
	Dallas, TX				
	Denton, TX				
	Ellis, TX				
	Henderson, TX				
	Hunt, TX				
	Kaufman, TX				
	Rockwall, TX				
1950	Danville, VA	0.9035	0.9807	0.9614	0.9421
	Danville City, VA				
	Pittsylvania, VA				
1960	Davenport-Moline-Rock Island, IA–IL	0.8985	0.9797	0.9594	0.9391
	Scott, IA				
	Henry, IL				
	Rock Island, IL				
2000	Dayton-Springfield, OH	0.9518	0.9904	0.9807	0.9711
	Clark, OH				
	Greene, OH				
	Miami, OH				
	Montgomery, OH				
2020	Daytona Beach, FL	0.9078	0.9816	0.9631	0.9447
	Flagler, FL				
	Volusia, FL				
2030	Decatur, AL	0.8828	0.9766	0.9531	0.9297
	Lawrence, AL				
	Morgan, AL				
2040	Decatur, IL	0.8161	0.9632	0.9264	0.8897
	Macon, IL				
2080	Denver, CO	1.0837	1.0167	1.0335	1.0502
	Adams, CO				
	Arapahoe, CO				
	Denver, CO				
	Douglas, CO				
	Jefferson, CO				
2120	Des Moines, IA	0.9106	0.9821	0.9642	0.9464
	Dallas, IA				
	Polk, IA				
	Warren, IA				
2160	Detroit, MI	1.0101	1.0020	1.0040	1.0061
	Lapeer, MI				
	Macomb, MI				
	Monroe, MI				
	Oakland, MI				
	St. Clair, MI				
	Wayne, MI				
2180	Dothan, AL	0.7741	0.9548	0.9096	0.8645
	Dale, AL				
	Houston, AL				
2190	Dover, DE	0.9805	0.9961	0.9922	0.9883
	Kent, DE				
2200	Dubuque, IA	0.8886	0.9777	0.9554	0.9332
	Dubuque, IA				
2240	Duluth-Superior, MN–WI	1.0171	1.0034	1.0068	1.0103
	St. Louis, MN				
	Douglas, WI				
2281	Dutchess County, NY	1.0934	1.0187	1.0374	1.0560
	Dutchess, NY				
2290	Eau Claire, WI	0.9064	0.9813	0.9626	0.9438
	Chippewa, WI				
	Eau Claire, WI				
2320	El Paso, TX	0.9196	0.9839	0.9678	0.9518
	El Paso, TX				
2330	Elkhart-Goshen, IN	0.9783	0.9957	0.9913	0.9870
	Elkhart, IN				

TABLE 1.—LONG-TERM CARE HOSPITAL PROPOSED WAGE INDEX FOR URBAN AREAS FOR DISCHARGES OCCURRING FROM JULY 1, 2004 THROUGH JUNE 30, 2005—Continued

MSA	Urban area (constituent counties)	Full wage index [1]	1/5th wage index [2]	2/5ths wage index [3]	3/5ths wage index [4]
2335	Elmira, NY	0.8377	0.9675	0.9351	0.9026
	Chemung, NY				
2340	Enid, OK	0.8559	0.9712	0.9424	0.9135
	Garfield, OK				
2360	Erie, PA	0.8601	0.9720	0.9440	0.9161
	Erie, PA				
2400	Eugene-Springfield, OR	1.1456	1.0291	1.0582	1.0874
	Lane, OR				
2440	Evansville-Henderson, IN–KY (in hospitals)	0.8429	0.9686	0.9372	0.9057
	Posey, IN				
	Vanderburgh, IN				
	Warrick, IN				
	Henderson, KY				
2520	Fargo-Moorhead, ND–MN	0.9797	0.9959	0.9919	0.9878
	Clay, MN				
	Cass, ND				
2560	Fayetteville, NC	0.8986	0.9797	0.9594	0.9392
	Cumberland, NC				
2580	Fayetteville-Springdale-Rogers, AR	0.8396	0.9679	0.9358	0.9038
	Benton, AR				
	Washington, AR				
2620	Flagstaff, AZ–UT	1.1333	1.0267	1.0533	1.0800
	Coconino, AZ				
	Kane, UT				
2640	Flint, MI	1.0858	1.0172	1.0343	1.0515
	Genesee, MI				
2650	Florence, AL	0.7747	0.9549	0.9099	0.8648
	Colbert, AL				
	Lauderdale, AL				
2655	Florence, SC	0.8709	0.9742	0.9484	0.9225
	Florence, SC				
2670	Fort Collins-Loveland, CO	1.0108	1.0022	1.0043	1.0065
	Larimer, CO				
2680	Ft. Lauderdale, FL	1.0163	1.0033	1.0065	1.0098
	Broward, FL				
2700	Fort Myers-Cape Coral, FL	0.9816	0.9963	0.9926	0.9890
	Lee, FL				
2710	Fort Pierce-Port St. Lucie, FL	1.0008	1.0002	1.0003	1.0005
	Martin, FL				
	St. Lucie, FL				
2720	Fort Smith, AR–OK	0.8424	0.9685	0.9370	0.9054
	Crawford, AR				
	Sebastian, AR				
	Sequoyah, OK				
2750	Fort Walton Beach, FL	0.8966	0.9793	0.9586	0.9380
	Okaloosa, FL				
2760	Fort Wayne, IN	0.9585	0.9917	0.9834	0.9751
	Adams, IN				
	Allen, IN				
	De Kalb, IN				
	Huntington, IN				
	Wells, IN				
	Whitley, IN				
2800	Forth Worth-Arlington, TX	0.9359	0.9872	0.9744	0.9615
	Hood, TX				
	Johnson, TX				
	Parker, TX				
	Tarrant, TX				
2840	Fresno, CA	1.0094	1.0019	1.0038	1.0056
	Fresno, CA				
	Madera, CA				
2880	Gadsden, AL	0.8206	0.9641	0.9282	0.8924
	Etowah, AL				
2900	Gainesville, FL	0.9693	0.9939	0.9877	0.9816
	Alachua, FL				
2920	Galveston-Texas City, TX	0.9279	0.9856	0.9712	0.9567
	Galveston, TX				
2960	Gary, IN	0.9410	0.9882	0.9764	0.9646
	Lake, IN				
	Porter, IN				

TABLE 1.—LONG-TERM CARE HOSPITAL PROPOSED WAGE INDEX FOR URBAN AREAS FOR DISCHARGES OCCURRING FROM JULY 1, 2004 THROUGH JUNE 30, 2005—Continued

MSA	Urban area (constituent counties)	Full wage index [1]	1/5th wage index [2]	2/5ths wage index [3]	3/5ths wage index [4]
2975	Glens Falls, NY	0.8475	0.9695	0.9390	0.9085
	Warren, NY				
	Washington, NY				
2980	Goldsboro, NC	0.8622	0.9724	0.9449	0.9173
	Wayne, NC				
2985	Grand Forks, ND–MN	0.8636	0.9727	0.9454	0.9182
	Polk, MN				
	Grand Forks, ND				
2995	Grand Junction, CO	0.9633	0.9927	0.9853	0.9780
	Mesa, CO				
3000	Grand Rapids-Muskegon-Holland, MI	0.9469	0.9894	0.9788	0.9681
	Allegan, MI				
	Kent, MI				
	Muskegon, MI				
	Ottawa, MI				
3040	Great Falls, MT	0.8809	0.9762	0.9524	0.9285
	Cascade, MT				
3060	Greeley, CO	0.9372	0.9874	0.9749	0.9623
	Weld, CO				
3080	Green Bay, WI	0.9461	0.9892	0.9784	0.9677
	Brown, WI				
3120	Greensboro-Winston-Salem-High Point, NC	0.9166	0.9833	0.9666	0.9500
	Alamance, NC				
	Davidson, NC				
	Davie, NC				
	Forsyth, NC				
	Guilford, NC				
	Randolph, NC				
	Stokes, NC				
	Yadkin, NC				
3150	Greenville, NC	0.9098	0.9820	0.9639	0.9459
	Pitt, NC				
3160	Greenville-Spartanburg-Anderson, SC	0.9335	0.9867	0.9734	0.9601
	Anderson, SC				
	Cherokee, SC				
	Greenville, SC				
	Pickens, SC				
	Spartanburg, SC				
3180	Hagerstown, MD	0.9172	0.9834	0.9669	0.9503
	Washington, MD				
3200	Hamilton-Middletown, OH	0.9214	0.9843	0.9686	0.9528
	Butler, OH				
3240	Harrisburg-Lebanon-Carlisle, PA	0.9164	0.9833	0.9666	0.9498
	Cumberland, PA				
	Dauphin, PA				
	Lebanon, PA				
	Perry, PA				
3283	Hartford, CT	1.1555	1.0311	1.0622	1.0933
	Litchfield, CT				
	Middlesex, CT				
	Tolland, CT				
3285	Hattiesburg, MS	0.7307	0.9461	0.8923	0.8384
	Forrest, MS				
	Lamar, MS				
3290	Hickory-Morganton-Lenoir, NC	0.9242	0.9848	0.9697	0.9545
	Alexander, NC				
	Burke, NC				
	Caldwell, NC				
	Catawba, NC				
3320	Honolulu, HI	1.1098	1.0220	1.0439	1.0659
	Honolulu, HI				
3350	Houma, LA	0.7748	0.9550	0.9099	0.8649
	Lafourche, LA				
	Terrebonne, LA				
3360	Houston, TX	0.9834	0.9967	0.9934	0.9900
	Chambers, TX				
	Fort Bend, TX				
	Harris, TX				
	Liberty, TX				
	Montgomery, TX				

TABLE 1.—LONG-TERM CARE HOSPITAL PROPOSED WAGE INDEX FOR URBAN AREAS FOR DISCHARGES OCCURRING FROM JULY 1, 2004 THROUGH JUNE 30, 2005—Continued

MSA	Urban area (constituent counties)	Full wage index [1]	1/5th wage index [2]	2/5ths wage index [3]	3/5ths wage index [4]
	Waller, TX				
3400	Huntington-Ashland, WV–KY–OH	0.9595	0.9919	0.9838	0.9757
	Boyd, KY				
	Carter, KY				
	Greenup, KY				
	Lawrence, OH				
	Cabell, WV				
	Wayne, WV				
3440	Huntsville, AL	0.9245	0.9849	0.9698	0.9547
	Limestone, AL				
	Madison, AL				
3480	Indianapolis, IN	0.9916	0.9983	0.9966	0.9950
	Boone, IN				
	Hamilton, IN				
	Hancock, IN				
	Henricks, IN				
	Johnson, IN				
	Madison, IN				
	Marion, IN				
	Morgan, IN				
	Shelby, IN				
3500	Iowa City, IA	0.9548	0.9910	0.9819	0.9729
	Johnson, IA				
3520	Jackson, MI	0.8986	0.9797	0.9594	0.9392
3560	Jackson, MS	0.8357	0.9671	0.9343	0.9014
	Hinds, MS				
	Madison, MS				
	Rankin, MS				
3580	Jackson, TN	0.8984	0.9797	0.9594	0.9390
	Madison, TN				
	Chester, TN				
3600	Jacksonville, FL	0.9529	0.9906	0.9812	0.9717
	Clay, FL				
	Duval, FL				
	Nasssau, FL				
	St. Johns, FL				
3605	Jacksonville, NC	0.8544	0.9709	0.9418	0.9126
	Onslow, NC				
3610	Jamestown, NY	0.7762	0.9552	0.9105	0.8657
	Chautauqua, NY				
3620	Janesville-Beloit, WI	0.9282	0.9856	0.9713	0.9569
	Rock, WI				
3640	Jersey City, NJ	1.1115	1.0223	1.0446	1.0669
	Hudson, NJ				
3660	Johnson City-Kingsport-Bristol, TN–VA	0.8253	0.9651	0.9301	0.8952
	Carter, TN				
	Hawkins, TN				
	Sullivan, TN				
	Unicoi, TN				
	Washington, TN				
	Bristol City, VA				
	Scott, VA				
	Washington, VA				
3680	Johnstown, PA	0.8158	0.9632	0.9263	0.8895
	Cambria, PA				
	Somerset, PA				
3700	Jonesboro, AR	0.7794	0.9559	0.9118	0.8676
	Craighead, AR				
3710	Joplin, MO	0.8681	0.9736	0.9472	0.9209
	Jasper, MO				
	Newton, MO				
3720	Kalamazoo-Battlecreek, MI	1.0500	1.0100	1.0200	1.0300
	Calhoun, MI				
	Kalamazoo, MI				
	Van Buren, MI				
3740	Kankakee, IL	1.0419	1.0084	1.0168	1.0251
	Kankakee, IL				
3760	Kansas City, KS–MO	0.9715	0.9943	0.9886	0.9829
	Johnson, KS				
	Leavenworth, KS				

TABLE 1.—LONG-TERM CARE HOSPITAL PROPOSED WAGE INDEX FOR URBAN AREAS FOR DISCHARGES OCCURRING FROM JULY 1, 2004 THROUGH JUNE 30, 2005—Continued

MSA	Urban area (constituent counties)	Full wage index[1]	1/5th wage index[2]	2/5ths wage index[3]	3/5ths wage index[4]
	Miami, KS				
	Wyandotte, KS				
	Cass, MO				
	Clay, MO				
	Clinton, MO				
	Jackson, MO				
	Lafayette, MO				
	Platte, MO				
	Ray, MO				
3800	Kenosha, WI	0.9761	0.9952	0.9904	0.9857
	Kenosha, WI				
3810	Killeen-Temple, TX	0.9159	0.9832	0.9664	0.9495
	Bell, TX				
	Coryell, TX				
3840	Knoxville, TN	0.8820	0.9764	0.9528	0.9292
	Anderson, TN				
	Blount, TN				
	Knox, TN				
	Loudon, TN				
	Sevier, TN				
	Union, TN				
3850	Kokomo, In	0.9045	0.9809	0.9618	0.9427
	Howard, IN				
	Tipton, IN				
3870	La Crosse, WI–MN	0.9247	0.9849	0.9699	0.9548
	Houston, MN				
	La Crosse, WI				
3880	Lafayette, LA	0.8189	0.9638	0.9276	0.8913
	Acadia, LA				
	Lafayette, LA				
	St. Landry, LA				
	St. Martin, LA				
3920	Lafayette, IN	0.8584	0.9717	0.9434	0.9150
	Clinton, IN				
	Tippecanoe, IN				
3960	Lake Charles, LA	0.7841	0.9568	0.9136	0.8705
	Calcasieu, LA				
3980	Lakeland-Winter Haven, FL	0.8811	0.9762	0.9524	0.9287
	Polk, FL				
4000	Lancaster, PA	0.9282	0.9856	0.9713	0.9569
	Lancaster, PA				
4040	Lansing-East Lansing, MI	0.9714	0.9943	0.9886	0.9828
	Clinton, MI				
	Eaton, MI				
	Ingham, MI				
4080	Laredo, TX	0.8091	0.9618	0.9236	0.8855
	Webb, TX				
4100	Las Cruces, NM	0.8688	0.9738	0.9475	0.9213
	Dona Ana, NM				
4120	Las Vegas, NV–AZ	1.1528	1.0306	1.0611	1.0917
	Mohave, AZ				
	Clark, NV				
	Nye, NV				
4150	Lawrence, KS	0.8677	0.9735	0.9471	0.9206
	Douglas, KS				
4200	Lawton, OK	0.8267	0.9653	0.9307	0.8960
	Comanche, OK				
4243	Lewiston-Auburn, ME	0.9383	0.9877	0.9753	0.9630
	Androscoggin, ME				
4280	Lexington, KY	0.8685	0.9737	0.9474	0.9211
	Bourbon, KY				
	Clark, KY				
	Fayette, KY				
	Jessamine, KY				
	Madison, KY				
	Scott, KY				
	Woodford, KY				
4320	Lima, OH	0.9522	0.9904	0.9809	0.9713
	Allen, OH				
	Auglaize, OH				

TABLE 1.—LONG-TERM CARE HOSPITAL PROPOSED WAGE INDEX FOR URBAN AREAS FOR DISCHARGES OCCURRING FROM JULY 1, 2004 THROUGH JUNE 30, 2005—Continued

MSA	Urban area (constituent counties)	Full wage index [1]	1/5th wage index [2]	2/5ths wage index [3]	3/5ths wage index [4]
4360	Lincoln, NE	1.0033	1.0007	1.0013	1.0020
	Lancaster, NE				
4400	Little Rock-North Little Rock, AR	0.8923	0.9785	0.9569	0.9354
	Faulkner, AR				
	Lonoke, AR				
	Pulaski, AR				
	Saline, AR				
4420	Longview-Marshall, TX	0.9113	0.9823	0.9645	0.9468
	Gregg, TX				
	Harrison, TX				
	Upshur, TX				
4480	Los Angeles-Long Beach, CA	1.1795	1.0359	1.0718	1.1077
	Los Angeles, CA				
4520	Louisville, KY–IN[1]	0.9242	0.9848	0.9697	0.9545
	Clark, IN				
	Floyd, IN				
	Harrison, IN				
	Scott, IN				
	Bullitt, KY				
	Jefferson, KY				
	Oldham, KY				
4600	Lubbock, TX	0.8272	0.9654	0.9309	0.8963
	Lubbock, TX				
4640	Lynchburg, VA	0.9134	0.9827	0.9654	0.9480
	Amherst, VA				
	Bedford, VA				
	Bedford City, VA				
	Campbell, VA				
	Lynchburg City, VA				
4680	Macon, GA	0.8953	0.9791	0.9581	0.9372
	Bibb, GA				
	Houston, GA				
	Jones, GA				
	Peach, GA				
	Twiggs, GA				
4720	Madison, WI	1.0264	1.0053	1.0106	1.0158
	Dane, WI				
4800	Mansfield, OH	0.9180	0.9836	0.9672	0.9508
	Crawford, OH				
	Richland, OH				
4840	Mayaguez, PR	0.4795	0.8959	0.7918	0.6877
	Anasco, PR				
	Cabo Rojo, PR				
	Hormigueros, PR				
	Mayaguez, PR				
	Sabana Grande, PR				
	San German, PR				
4880	McAllen-Edinburg-Mission, TX	0.8381	0.9676	0.9352	0.9029
	Hidalgo, TX				
4890	Medford-Ashland, OR	1.0772	1.0154	1.0309	1.0463
	Jackson, OR				
4900	Melbourne-Titusville-Palm Bay, FL	0.9776	0.9955	0.9910	0.9866
	Brevard, FL				
4920	Memphis, TN–AR–MS	0.9009	0.9802	0.9604	0.9405
	Crittenden, AR				
	DeSoto, MS				
	Fayette, TN				
	Shelby, TN				
	Tipton, TN				
4940	Merced, CA	0.9690	0.9938	0.9876	0.9814
	Merced, CA				
5000	Miami, FL	0.9894	0.9979	0.9958	0.9936
	Dade, FL				
5015	Middlesex-Somerset-Hunterdon, NJ	1.1366	1.0273	1.0546	1.0820
	Hunterdon, NJ				
	Middlesex, NJ				
	Somerset, NJ				
5080	Milwaukee-Waukesha, WI	0.9988	0.9998	0.9995	0.9993
	Milwaukee, WI				
	Ozaukee, WI				

TABLE 1.—LONG-TERM CARE HOSPITAL PROPOSED WAGE INDEX FOR URBAN AREAS FOR DISCHARGES OCCURRING FROM JULY 1, 2004 THROUGH JUNE 30, 2005—Continued

MSA	Urban area (constituent counties)	Full wage index [1]	1/5th wage index [2]	2/5ths wage index [3]	3/5ths wage index [4]
	Washington, WI				
	Waukesha, WI				
5120	Minneapolis-St. Paul, MN–WI	1.1001	1.0200	1.0400	1.0601
	Anoka, MN				
	Carver, MN				
	Chisago, MN				
	Dakota, MN				
	Hennepin, MN				
	Isanti, MN				
	Ramsey, MN				
	Scott, MN				
	Sherburne, MN				
	Washington, MN				
	Wright, MN				
	Pierce, WI				
	St. Croix, WI				
5140	Missoula, MT	0.8718	0.9744	0.9487	0.9231
	Missoula, MT				
5160	Mobile, AL	0.7994	0.9599	0.9198	0.8796
	Baldwin, AL				
	Mobile, AL				
5170	Modesto, CA	1.1275	1.0255	1.0510	1.0765
	Stanislaus, CA				
5190	Monmouth-Ocean, NJ	1.0956	1.0191	1.0382	1.0574
	Monmouth, NJ				
	Ocean, NJ				
5200	Monroe, LA	0.7922	0.9584	0.9169	0.8753
	Ouachita, LA				
5240	Montgomery, AL	0.7907	0.9581	0.9163	0.8744
	Autauga, AL				
	Elmore, AL				
	Montgomery, AL				
5280	Muncie, IN	0.8775	0.9755	0.9510	0.9265
	Delaware, IN				
5330	Myrtle Beach, SC	0.9112	0.9822	0.9645	0.9467
	Horry, SC				
5345	Naples, FL	0.9790	0.9958	0.9916	0.9874
	Collier, FL				
5360	Nashville, TN	0.9855	0.9971	0.9942	0.9913
	Cheatham, TN				
	Davidson, TN				
	Dickson, TN				
	Robertson, TN				
	Rutherford TN				
	Sumner, TN				
	Williamson, TN				
	Wilson, TN				
5380	Nassau-Suffolk, NY	1.3140	1.0628	1.1256	1.1884
	Nassau, NY				
	Suffolk, NY				
5483	New Haven-Bridgeport-Stamford-Waterbury, CT	1.2385	1.0477	1.0954	1.1431
	Danbury, CT				
	Fairfield, CT				
	New Haven, CT				
5523	New London-Norwich, CT	1.1631	1.0326	1.0652	1.0979
	New London, CT				
5560	New Orleans, LA	0.9174	0.9835	0.9670	0.9504
	Jefferson, LA				
	Orleans, LA				
	Plaquemines, LA				
	St. Bernard, LA				
	St. Charles, LA				
	St. James, LA				
	St. John The Baptist, LA				
	St. Tammany, LA				
5600	New York, NY	1.4018	1.0804	1.1607	1.2411
	Bronx, NY				
	Kings, NY				
	New York, NY				
	Putnam, NY				

TABLE 1.—LONG-TERM CARE HOSPITAL PROPOSED WAGE INDEX FOR URBAN AREAS FOR DISCHARGES OCCURRING FROM JULY 1, 2004 THROUGH JUNE 30, 2005—Continued

MSA	Urban area (constituent counties)	Full wage index [1]	1/5th wage index [2]	2/5ths wage index [3]	3/5ths wage index [4]
	Queens, NY				
	Richmond, NY				
	Rockland, NY				
	Westchester, NY				
5640	Newark, NJ	1.1518	1.0304	1.0607	1.0911
	Essex, NJ				
	Morris, NJ				
	Sussex, NJ				
	Union, NJ				
	Warren, NJ				
5660	Newburgh, NY–PA	1.1509	1.0302	1.0604	1.0905
	Orange, NY				
	Pike, PA				
5720	Norfolk-Virginia Beach-Newport News, VA–NC	0.8619	0.9724	0.9448	0.9171
	Currituck, NC				
	Chesapeake City, VA				
	Gloucester, VA				
	Hampton City, VA				
	Isle of Wight, VA				
	James City, VA				
	Mathews, VA				
	Newport News City, VA				
	Norfolk City, VA				
	Poquoson City, VA				
	Portsmouth City, VA				
	Suffolk City, VA				
	Virginia Beach City, VA				
	Williamsburg City, VA				
	York, VA				
5775	Oakland, CA	1.4921	1.0984	1.1968	1.2953
	Alameda, CA				
	Contra Costa, CA				
5790	Ocala, FL	0.9728	0.9946	0.9891	0.9837
	Marion, FL				
5800	Odessa-Midland, TX	0.9327	0.9865	0.9731	0.9596
	Ector, TX				
	Midland, TX				
5880	Oklahoma City, OK	0.8984	0.9797	0.9594	0.9390
	Canadian, OK				
	Cleveland, OK				
	Logan, OK				
	McClain, OK				
	Oklahoma, OK				
	Pottawatomie, OK				
5910	Olympia, WA	1.0963	1.0193	1.0385	1.0578
	Thurston, WA				
5920	Omaha, NE–IA	0.9745	0.9949	0.9898	0.9847
	Pottawattamie, IA				
	Cass, NE				
	Douglas, NE				
	Sarpy, NE				
	Washington, NE				
5945	Orange County, CA	1.1372	1.0274	1.0549	1.0823
	Orange, CA				
5960	Orlando, FL	0.9654	0.9931	0.9862	0.9792
	Lake, FL				
	Orange, FL				
	Osceola, FL				
	Seminole, FL				
5990	Owensboro, KY	0.8374	0.9675	0.9350	0.9024
	Daviess, KY				
6015	Panama City, FL	0.8202	0.9640	0.9281	0.8921
	Bay, FL				
6020	Parkersburg-Marietta, WV–OH	0.8039	0.9608	0.9216	0.8823
	Washington, OH				
	Wood, WV				
6080	Pensacola, FL	0.8707	0.9741	0.9483	0.9224
	Escambia, FL				
	Santa Rosa, FL				
6120	Peoria-Pekin, IL	0.8734	0.9747	0.9494	0.9240

TABLE 1.—LONG-TERM CARE HOSPITAL PROPOSED WAGE INDEX FOR URBAN AREAS FOR DISCHARGES OCCURRING FROM JULY 1, 2004 THROUGH JUNE 30, 2005—Continued

MSA	Urban area (constituent counties)	Full wage index [1]	1/5th wage index [2]	2/5ths wage index [3]	3/5ths wage index [4]
	Peoria, IL				
	Tazewell, IL				
	Woodford, IL				
6160	Philadelphia, PA–NJ	1.0883	1.0177	1.0353	1.0530
	Burlington, NJ				
	Camden, NJ				
	Gloucester, NJ				
	Salem, NJ				
	Bucks, PA				
	Chester, PA				
	Delaware, PA				
	Montgomery, PA				
	Philadelphia, PA				
6200	Phoenix-Mesa, AZ	1.0129	1.0026	1.0052	1.0077
	Maricopa, AZ				
	Pinal, AZ				
6240	Pine Bluff, AR	0.7865	0.9573	0.9146	0.8719
	Jefferson, AR				
6280	Pittsburgh, PA	0.8901	0.9780	0.9560	0.9341
	Allegheny, PA				
	Beaver, PA				
	Butler, PA				
	Fayette, PA				
	Washington, PA				
	Westmoreland, PA				
6323	Pittsfield, MA	1.0276	1.0055	1.0110	1.0166
	Berkshire, MA				
6340	Pocatello, ID	0.9042	0.9808	0.9617	0.9425
	Bannock, ID				
6360	Ponce, PR	0.4708	0.8942	0.7883	0.6825
	Guayanilla, PR				
	Juana Diaz, PR				
	Penuelas, PR				
	Ponce, PR				
	Villalba, PR				
	Yauco, PR				
6403	Portland, ME	0.9949	0.9990	0.9980	0.9969
	Cumberland, ME				
	Sagadahoc, ME				
	York, ME				
6440	Portland-Vancouver, OR–WA	1.1213	1.0243	1.0485	1.0728
	Clackamas, OR				
	Columbia, OR				
	Multnomah, OR				
	Washington, OR				
	Yamhill, OR				
	Clark, WA				
6483	Providence-Warwick-Pawtucket, RI	1.0977	1.0195	1.0391	1.0586
	Bristol, RI				
	Kent, RI				
	Newport, RI				
	Providence, RI				
	Washington, RI				
6520	Provo-Orem, UT	0.9976	0.9995	0.9990	0.9986
	Utah, UT				
6560	Pueblo, CO	0.8778	0.9756	0.9511	0.9267
	Pueblo, CO				
6580	Punta Gorda, FL	0.9510	0.9902	0.9804	0.9706
	Charlotte, FL				
6600	Racine, WI	0.8814	0.9763	0.9526	0.9288
	Racine, WI				
6640	Raleigh-Durham-Chapel Hill, NC	0.9959	0.9992	0.9984	0.9975
	Chatham, NC				
	Durham, NC				
	Franklin, NC				
	Johnston, NC				
	Orange, NC				
	Wake, NC				
6660	Rapid City, SD	0.8806	0.9761	0.9522	0.9284
	Pennington, SD				

TABLE 1.—LONG-TERM CARE HOSPITAL PROPOSED WAGE INDEX FOR URBAN AREAS FOR DISCHARGES OCCURRING FROM JULY 1, 2004 THROUGH JUNE 30, 2005—Continued

MSA	Urban area (constituent counties)	Full wage index [1]	1/5th wage index [2]	2/5ths wage index [3]	3/5ths wage index [4]
6680	Reading, PA	0.9133	0.9827	0.9653	0.9480
	Berks, PA				
6690	Redding, CA	1.1352	1.0270	1.0541	1.0811
	Shasta, CA				
6720	Reno, NV	1.0682	1.0136	1.0273	1.0409
	Washoe, NV				
6740	Richland-Kennewick-Pasco, WA	1.0609	1.0122	1.0244	1.0365
	Benton, WA				
	Franklin, WA				
6760	Richmond-Petersburg, VA	0.9349	0.9870	0.9740	0.9609
	Charles City County, VA				
	Chesterfield, VA				
	Colonial Heights City, VA				
	Dinwiddie, VA				
	Goochland, VA				
	Hanover, VA				
	Henrico, VA				
	Hopewell City, VA				
	New Kent, VA				
	Petersburg City, VA				
	Powhatan, VA				
	Prince George, VA				
	Richmond City, VA				
6780	Riverside-San Bernardino, CA	1.1341	1.0268	1.0536	1.0805
	Riverside, CA				
	San Bernardino, CA				
6800	Roanoke, VA	0.8700	0.9740	0.9480	0.9220
	Botetourt, VA				
	Roanoke, VA				
	Roanoke City, VA				
	Salem City, VA				
6820	Rochester, MN	1.1739	1.0348	1.0696	1.1043
	Olmsted, MN				
6840	Rochester, NY	0.9430	0.9886	0.9772	0.9658
	Genesee, NY				
	Livingston, NY				
	Monroe, NY				
	Ontario, NY				
	Orleans, NY				
	Wayne, NY				
6880	Rockford, IL	0.9666	0.9933	0.9866	0.9800
	Boone, IL				
	Ogle, IL				
	Winnebago, IL				
6895	Rocky Mount, NC	0.9076	0.9815	0.9630	0.9446
	Edgecombe, NC				
	Nash, NC				
6920	Sacramento, CA	1.1845	1.0369	1.0738	1.1107
	El Dorado, CA				
	Placer, CA				
	Sacramento, CA				
6960	Saginaw-Bay City-Midland, MI	1.0032	1.0006	1.0013	1.0019
	Bay, MI				
	Midland, MI				
	Saginaw, MI				
6980	St. Cloud, MN	0.9506	0.9901	0.9802	0.9704
	Benton, MN				
	Stearns, MN				
7000	St. Joseph, MO	0.9757	0.9951	0.9903	0.9854
	Andrew, MO				
	Buchanan, MO				
7040	St. Louis, MO–IL	0.9033	0.9807	0.9613	0.9420
	Clinton, IL				
	Jersey, IL				
	Madison, IL				
	Monroe, IL				
	St. Clair, IL				
	Franklin, MO				
	Jefferson, MO				
	Lincoln, MO				

TABLE 1.—LONG-TERM CARE HOSPITAL PROPOSED WAGE INDEX FOR URBAN AREAS FOR DISCHARGES OCCURRING FROM JULY 1, 2004 THROUGH JUNE 30, 2005—Continued

MSA	Urban area (constituent counties)	Full wage index [1]	1/5th wage index [2]	2/5ths wage index [3]	3/5ths wage index [4]
	St. Charles, MO				
	St. Louis, MO				
	St. Louis City, MO				
	Warren, MO				
7080	Salem, OR	1.0482	1.0096	1.0193	1.0289
	Marion, OR				
	Polk, OR				
7120	Salinas, CA	1.4339	1.0868	1.1736	1.2603
	Monterey, CA				
7160	Salt Lake City-Ogden, UT	0.9913	0.9983	0.9965	0.9948
	Davis, UT				
	Salt Lake, UT				
	Weber, UT				
7200	San Angelo, TX	0.8535	0.9707	0.9414	0.9121
	Tom Green, TX				
7240	San Antonio, TX	0.8870	0.9774	0.9548	0.9322
	Bexar, TX				
	Comal, TX				
	Guadalupe, TX				
	Wilson, TX				
7320	San Diego, CA	1.1147	1.0229	1.0459	1.0688
	San Diego, CA				
7360	San Francisco, CA	1.4514	1.0903	1.1806	1.2708
	Marin, CA				
	San Francisco, CA				
	San Mateo, CA				
7400	San Jose, CA	1.4626	1.0925	1.1850	1.2776
	Santa Clara, CA				
7440	San Juan-Bayamon, PR	0.4909	0.8982	0.7964	0.6945
	Aguas Buenas, PR				
	Barceloneta, PR				
	Bayamon, PR				
	Canovanas, PR				
	Carolina, PR				
	Catano, PR				
	Ceiba, PR				
	Comerio, PR				
	Corozal, PR				
	Dorado, PR				
	Fajardo, PR				
	Florida, PR				
	Guaynabo, PR				
	Humacao, PR				
	Juncos, PR				
	Los Piedras, PR				
	Loiza, PR				
	Luguillo, PR				
	Manati, PR				
	Morovis, PR				
	Naguabo, PR				
	Naranjito, PR				
	Rio Grande, PR				
	San Juan, PR				
	Toa Alta, PR				
	Toa Baja, PR				
	Trujillo Alto, PR				
	Vega Alta, PR				
	Vega Baja, PR				
	Yabucoa, PR				
7460	San Luis Obispo-Atascadero-Paso Robles, CA	1.1429	1.0286	1.0572	1.0857
	San Luis Obispo, CA				
7480	Santa Barbara-Santa Maria-Lompoc, CA	1.0441	1.0088	1.0176	1.0265
	Santa Barbara, CA				
7485	Santa Cruz-Watsonville, CA	1.2942	1.0588	1.1177	1.1765
	Santa Cruz, CA				
7490	Santa Fe, NM	1.0653	1.0131	1.0261	1.0392
	Los Alamos, NM				
	Santa Fe, NM				
7500	Santa Rosa, CA	1.2877	1.0575	1.1151	1.1726
	Sonoma, CA				

TABLE 1.—LONG-TERM CARE HOSPITAL PROPOSED WAGE INDEX FOR URBAN AREAS FOR DISCHARGES OCCURRING FROM JULY 1, 2004 THROUGH JUNE 30, 2005—Continued

MSA	Urban area (constituent counties)	Full wage index [1]	1/5th wage index [2]	2/5ths wage index [3]	3/5ths wage index [4]
7510	Sarasota-Bradenton, FL	0.9964	0.9993	0.9986	0.9978
	Manatee, FL				
	Sarasota, FL				
7520	Savannah, GA	0.9472	0.9894	0.9789	0.9683
	Bryan, GA				
	Chatham, GA				
	Effingham, GA				
7560	Scranton-Wilkes-Barre-Hazleton, PA	0.8412	0.9682	0.9365	0.9047
	Columbia, PA				
	Lackawanna, PA				
	Luzerne, PA				
	Wyoming, PA				
7600	Seattle-Bellevue-Everett, WA	1.1562	1.0312	1.0625	1.0937
	Island, WA				
	King, WA				
	Snohomish, WA				
7610	Sharon, PA	0.7751	0.9550	0.9100	0.8651
	Mercer, PA				
7620	Sheboygan, WI	0.8624	0.9725	0.9450	0.9174
	Sheboygan, WI				
7640	Sherman-Denison, TX	0.9700	0.9940	0.9880	0.9820
	Grayson, TX				
7680	Shreveport-Bossier City, LA	0.9083	0.9817	0.9633	0.9450
	Bossier, LA				
	Caddo, LA				
	Webster, LA				
7720	Sioux City, IA–NE	0.8993	0.9799	0.9597	0.9396
	Woodbury, IA				
	Dakota, NE				
7760	Sioux Falls, SD	0.9309	0.9862	0.9724	0.9585
	Lincoln, SD				
	Minnehaha, SD				
7800	South Bend, IN	0.9821	0.9964	0.9928	0.9893
	St. Joseph, IN				
7840	Spokane, WA	1.0901	1.0180	1.0360	1.0541
	Spokane, WA				
7880	Springfield, IL	0.8944	0.9789	0.9578	0.9366
	Menard, IL				
	Sangamon, IL				
7920	Springfield, MO	0.8457	0.9691	0.9383	0.9074
	Christian, MO				
	Greene, MO				
	Webster, MO				
8003	Springfield, MA	1.0543	1.0109	1.0217	1.0326
	Hampden, MA				
	Hampshire, MA				
8050	State College, PA	0.8740	0.9748	0.9496	0.9244
	Centre, PA				
8080	Steubenville-Weirton, OH–WV (WV Hospitals)	0.8398	0.9680	0.9359	0.9039
	Jefferson, OH				
	Brooke, WV				
	Hancock, WV				
8120	Stockton-Lodi, CA	1.0404	1.0081	1.0162	1.0242
	San Joaquin, CA				
8140	Sumter, SC	0.8243	0.9649	0.9297	0.8946
	Sumter, SC				
8160	Syracuse, NY	0.9412	0.9882	0.9765	0.9647
	Cayuga, NY				
	Madison, NY				
	Onondaga, NY				
	Oswego, NY				
8200	Tacoma, WA	1.1116	1.0223	1.0446	1.0670
	Pierce, WA				
8240	Tallahassee, FL	0.8520	0.9704	0.9408	0.9112
	Gadsden, FL				
	Leon, FL				
8280	Tampa-St. Petersburg-Clearwater, FL	0.9103	0.9821	0.9641	0.9462
	Hernando, FL				
	Hillsborough, FL				
	Pasco, FL				

TABLE 1.—LONG-TERM CARE HOSPITAL PROPOSED WAGE INDEX FOR URBAN AREAS FOR DISCHARGES OCCURRING FROM JULY 1, 2004 THROUGH JUNE 30, 2005—Continued

MSA	Urban area (constituent counties)	Full wage index [1]	1/5th wage index [2]	2/5ths wage index [3]	3/5ths wage index [4]
	Pinellas, FL				
8320	Terre Haute, IN	0.8325	0.9665	0.9330	0.8995
	Clay, IN				
	Vermillion, IN				
	Vigo, IN				
8360	Texarkana, AR–Texarkana, TX	0.8150	0.9630	0.9260	0.8890
	Miller, AR				
	Bowie, TX				
8400	Toledo, OH	0.9381	0.9876	0.9752	0.9629
	Fulton, OH				
	Lucas, OH				
	Wood, OH				
8440	Topeka, KS	0.9108	0.9822	0.9643	0.9465
	Shawnee, KS				
8480	Trenton, NJ	1.0517	1.0103	1.0207	1.0310
	Mercer, NJ				
8520	Tucson, AZ	0.8981	0.9796	0.9592	0.9389
	Pima, AZ				
8560	Tulsa, OK	0.9185	0.9837	0.9674	0.9511
	Creek, OK				
	Osage, OK				
	Rogers, OK				
	Tulsa, OK				
	Wagoner, OK				
8600	Tuscaloosa, AL	0.8212	0.9642	0.9285	0.8927
	Tuscaloosa, AL				
8640	Tyler, TX	0.9404	0.9881	0.9762	0.9642
	Smith, TX				
8680	Utica-Rome, NY	0.8403	0.9681	0.9361	0.9042
	Herkimer, NY				
	Oneida, NY				
8720	Vallejo-Fairfield-Napa, CA	1.3377	1.0675	1.1351	1.2026
	Napa, CA				
	Solano, CA				
8735	Ventura, CA	1.1064	1.0213	1.0426	1.0638
	Ventura, CA				
8750	Victoria, TX	0.8184	0.9637	0.9274	0.8910
	Victoria, TX				
8760	Vineland-Millville-Bridgeton, NJ	1.0405	1.0081	1.0162	1.0243
	Cumberland, NJ				
8780	Visalia-Tulare-Porterville, CA	0.9794	0.9959	0.9918	0.9876
	Tulare, CA				
8800	Waco, TX	0.8394	0.9679	0.9358	0.9036
	McLennan, TX				
8840	Washington, DC–MD–VA–WV	1.0904	1.0181	1.0362	1.0542
	District of Columbia, DC				
	Calvert, MD				
	Charles, MD				
	Frederick, MD				
	Montgomery, MD				
	Prince Georges, MD				
	Alexandria City, VA				
	Arlington, VA				
	Clarke, VA				
	Culpeper, VA				
	Fairfax, VA				
	Fairfax City, VA				
	Falls Church City, VA				
	Fauquier, VA				
	Fredericksburg City, VA				
	King George, VA				
	Loudoun, VA				
	Manassas City, VA				
	Manassas Park City, VA				
	Prince William, VA				
	Spotsylvania, VA				
	Stafford, VA				
	Warren, VA				
	Berkeley, WV				
	Jefferson, WV				

TABLE 1.—LONG-TERM CARE HOSPITAL PROPOSED WAGE INDEX FOR URBAN AREAS FOR DISCHARGES OCCURRING FROM JULY 1, 2004 THROUGH JUNE 30, 2005—Continued

MSA	Urban area (constituent counties)	Full wage index [1]	1/5th wage index [2]	2/5ths wage index [3]	3/5ths wage index [4]
8920	Waterloo-Cedar Falls, IA	0.8366	0.9673	0.9346	0.9020
	Black Hawk, IA				
8940	Wausau, WI	0.9692	0.9938	0.9877	0.9815
	Marathon, WI				
8960	West Palm Beach-Boca Raton, FL	0.9798	0.9960	0.9919	0.9879
	Palm Beach, FL				
9000	Wheeling, WV–OH	0.7494	0.9499	0.8998	0.8496
	Belmont, OH				
	Marshall, WV				
	Ohio, WV				
9040	Wichita, KS	0.9238	0.9848	0.9695	0.9543
	Butler, KS				
	Harvey, KS				
	Sedgwick, KS				
9080	Wichita Falls, TX	0.8341	0.9668	0.9336	0.9005
	Archer, TX				
	Wichita, TX				
9140	Williamsport, PA	0.8158	0.9632	0.9263	0.8895
	Lycoming, PA				
9160	Wilmington-Newark, DE–MD	1.0882	1.0176	1.0353	1.0529
	New Castle, DE				
	Cecil, MD				
9200	Wilmington, NC	0.9563	0.9913	0.9825	0.9738
	New Hanover, NC				
	Brunswick, NC				
9260	Yakima, WA	1.0372	1.0074	1.0149	1.0223
	Yakima, WA				
9270	Yolo, CA	0.9204	0.9841	0.9682	0.9522
	Yolo, CA				
9280	York, PA	0.9119	0.9824	0.9648	0.9471
	York, PA				
9320	Youngstown-Warren, OH	0.9214	0.9843	0.9686	0.9528
	Columbiana, OH				
	Mahoning, OH				
	Trumbull, OH				
9340	Yuba City, CA	1.0196	1.0039	1.0078	1.0118
	Sutter, CA				
	Yuba, CA				
9360	Yuma, AZ	0.8895	0.9779	0.9558	0.9337
	Yuma, AZ				

[1] Wage index calculated using the same wage data used to compute the wage index used by acute care hospitals under the IPPS for Federal FY 2004 (that is, fiscal year 2000 audited acute care hospital inpatient wage data) without regard to reclassification under section 1886(d)(8) or section 1886(d)(10) of the Act.

[2] One-fifth of the proposed full wage index value, applicable for a LTCH's cost reporting period beginning on or after October 1, 2002 through September 30, 2003 (Federal FY 2203). That is, for a LTCH's cost reporting period that began during Federal FY 2003 and located in Chicago, Illinois (MSA 1600), the proposed 1/5th wage index value is computed as (1.0892 + 4)/5 = 1.0178. For further details on the 5-year phase-in of the wage index, see section IV.C.1.of this proposed rule.

[3] Two-fifths of the proposed full wage index value, applicable for a LTCH's cost reporting period beginning on or after October 1, 2003 through September 30, 2004 (Federal FY 2004). That is, for a LTCH's cost reporting period that begins during Federal FY 2004 and located in Chicago, Illinois (MSA 1600), the proposed 2/5ths wage index value is computed as ((2*1.0892) + 3))/5 = 1.0357. For further details on the 5-year phase-in of the wage index, see section IV.C.1. of this proposed rule.

[4] Three-fifths of the proposed full wage index value, applicable for a LTCH's cost reporting period beginning on or after October 1, 2004 through September 30, 2005 (Federal FY 2005). That is, for a LTCH's cost reporting period that begins during Federal FY 2004 and located in Chicago, Illinois (MSA 1600), the proposed 3/5ths wage index value is computed as ((3*1.0892) + 2))/5 = 1.0535. For further details on the 5-year phase-in of the wage index, see section IV.C.1. of this proposed rule.

TABLE 2.—LONG-TERM CARE HOSPITAL PROPOSED WAGE INDEX FOR RURAL AREAS FOR DISCHARGES OCCURRING FROM JULY 1, 2004 THROUGH JUNE 30, 2005

Nonurban area	Full wage index [1]	⅕th wage index [2]	⅖ths wage index [3]	⅗ths wage index [4]
Alabama	0.7492	0.9498	0.8997	0.8495
Alaska	1.1886	1.0377	1.0754	1.1132
Arizona	0.9270	0.9854	0.9708	0.9562
Arkansas	0.7734	0.9547	0.9094	0.8640
California	1.0027	1.0005	1.0011	1.0016
Colorado	0.9328	0.9866	0.9731	0.9597
Connecticut	1.2183	1.0437	1.0873	1.1310
Delaware	0.9557	0.9911	0.9823	0.9734

TABLE 2.—LONG-TERM CARE HOSPITAL PROPOSED WAGE INDEX FOR RURAL AREAS FOR DISCHARGES OCCURRING FROM JULY 1, 2004 THROUGH JUNE 30, 2005—Continued

Nonurban area	Full wage index [1]	⅕th wage index [2]	⅖ths wage index [3]	⅗ths wage index [4]
Florida	0.8870	0.9774	0.9548	0.9322
Georgia	0.8595	0.9719	0.9438	0.9157
Hawaii	0.9958	0.9992	0.9983	0.9975
Idaho	0.8974	0.9795	0.9590	0.9384
Illinois	0.8254	0.9651	0.9302	0.8952
Indiana	0.8824	0.9765	0.9530	0.9294
Iowa	0.8416	0.9683	0.9366	0.9050
Kansas	0.8034	0.9607	0.9214	0.8820
Kentucky	0.7973	0.9595	0.9189	0.8784
Louisiana	0.7458	0.9492	0.8983	0.8475
Maine	0.8812	0.9762	0.9525	0.9287
Maryland	0.9125	0.9825	0.9650	0.9475
Massachusetts	1.0432	1.0086	1.0173	1.0259
Michigan	0.8884	0.9777	0.9554	0.9330
Minnesota	0.9330	0.9866	0.9732	0.9598
Mississippi	0.7778	0.9556	0.9111	0.8667
Missouri	0.7892	0.9578	0.9157	0.8735
Montana	0.8800	0.9760	0.9520	0.9280
Nebraska	0.8822	0.9764	0.9529	0.9293
Nevada	0.9806	0.9961	0.9922	0.9884
New Hampshire	1.0030	1.0006	1.0012	1.0018
New Jersey [5]	....	....	....	....
New Mexico	0.8270	0.9654	0.9308	0.8962
New York	0.8526	0.9705	0.9410	0.9116
North Carolina	0.8458	0.9692	0.9383	0.9075
North Dakota	0.7778	0.9556	0.9111	0.8667
Ohio	0.8820	0.9764	0.9528	0.9292
Oklahoma	0.7537	0.9507	0.9015	0.8522
Oregon	0.9994	0.9999	0.9998	0.9996
Pennsylvania	0.8378	0.9676	0.9351	0.9027
Puerto Rico	0.4018	0.8804	0.7607	0.6411
Rhode Island [5]	....	....	....	....
South Carolina	0.8498	0.9700	0.9399	0.9099
South Dakota	0.8195	0.9639	0.9278	0.8917
Tennessee	0.7886	0.9577	0.9154	0.8732
Texas	0.7780	0.9556	0.9112	0.8668
Utah	0.8974	0.9795	0.9590	0.9384
Vermont	0.9307	0.9861	0.9723	0.9584
Virginia	0.8498	0.9700	0.9399	0.9099
Washington	1.0388	1.0078	1.0155	1.0233
West Virginia	0.8018	0.9604	0.9207	0.8811
Wisconsin	0.9304	0.9861	0.9722	0.9582
Wyoming	0.9110	0.9822	0.9644	0.9466

[1] Wage index calculated using the same wage data used to compute the wage index used by acute care hospitals under the IPPS for Federal FY 2004 (that is, fiscal year 2000 audited acute care hospital inpatient wage data) without regard to reclassification under section 1886(d)(8) or section 1886(d)(10) of the Act.

[2] One-fifth of the proposed full wage index value, applicable for a LTCH's cost reporting period beginning on or after October 1, 2002 through September 30, 2003 (Federal FY 2203). That is, for a LTCH's cost reporting period that began during Federal FY 2003 and located in rural Illinois, the proposed ⅕th wage index value is computed as (0.8254 + 4)/5 = 0.9651. For further details on the 5-year phase-in of the wage index, see section IV.C.1. of this proposed rule.

[3] Two-fifths of the proposed full wage index value, applicable for a LTCH's cost reporting period beginning on or after October 1, 2003 through September 30, 2004 (Federal FY 2004). That is, for a LTCH's cost reporting period that begins during Federal FY 2004 and located in rural Illinois, the proposed ⅖th wage index value is computed as ((2*0.8254) + 3))/5 = 0.9302. For further details on the 5-year phase-in of the wage index, see section IV.C.1. of this proposed rule.

[4] Three-fifths of the proposed full wage index value, applicable for a LTCH's cost reporting period beginning on or after October 1, 2004 through September 30, 2005 (Federal FY 2005). That is, for a LTCH's cost reporting period that begins during Federal FY 2004 and located in rural Illinois, the proposed ⅗ths wage index value is computed as ((3*0.8254) + 2))/5 = 0.8952. For further details on the 5-year phase-in of the wage index, see section IV.C.1. of this proposed rule.

[5] All counties within the State are classified as urban.

TABLE 3.—PROPOSED FEDERAL FY 2004 LTC–DRG RELATIVE WEIGHTS, GEOMETRIC MEAN LENGTH OF STAY, AND SHORT-STAYS OF FIVE-SIXTHS AVERAGE LENGTH OF STAY FOR DISCHARGES OCCURRING FROM OCTOBER 1, 2003 THROUGH SEPTEMBER 30, 2004

LTC–DRG	Description	Relative weight	Geometric average length of stay	5/6th of the average length of stay
1	CRANIOTOMY AGE >17 W CC [5]	2.0841	40.0	33.3

TABLE 3.—PROPOSED FEDERAL FY 2004 LTC–DRG RELATIVE WEIGHTS, GEOMETRIC MEAN LENGTH OF STAY, AND SHORT-STAYS OF FIVE-SIXTHS AVERAGE LENGTH OF STAY FOR DISCHARGES OCCURRING FROM OCTOBER 1, 2003 THROUGH SEPTEMBER 30, 2004—Continued

LTC–DRG	Description	Relative weight	Geometric average length of stay	5/6th of the average length of stay
2	CRANIOTOMY AGE > 17 W/O CC [8]	2.0841	40.0	33.3
3	CRANIOTOMY AGE 0–17 [8]	2.0841	40.0	33.3
6	CARPAL TUNNEL RELEASE [8]	0.4964	18.5	15.4
7	PERIPH & CRANIAL NERVE & OTHER NERV SYST PROC W CC [7]	1.5754	41.0	34.1
8	PERIPH & CRANIAL NERVE & OTHER NERV SYST PROC W/O CC [7]	1.5754	41.0	34.1
9	SPINAL DISORDERS & INJURIES	1.5025	32.9	27.4
10	NERVOUS SYSTEM NEOPLASMS W CC	0.7549	23.4	19.5
11	NERVOUS SYSTEM NEOPLASMS W/O CC	0.7281	22.0	18.3
12	DEGENERATIVE NERVOUS SYSTEM DISORDERS	0.7485	25.8	21.5
13	MULTIPLE SCLEROSIS & CEREBELLAR ATAXIA	0.7530	25.9	21.5
14	INTERCRANIAL HEMORRHAGE & STROKE W INFARCT	0.9196	27.4	22.8
15	NONSPECIFIC CVA & PRECEREBRAL OCCULUSION W/O INFARCT	0.8714	28.8	24.0
16	NONSPECIFIC CEREBROVASCULAR DISORDERS W CC	0.9125	23.9	19.9
17	NONSPECIFIC CEREBROVASCULAR DISORDERS W/O CC	0.5262	20.4	17.0
18	CRANIAL & PERIPHERAL NERVE DISORDERS W CC	0.8225	23.9	19.9
19	CRANIAL & PERIPHERAL NERVE DISORDERS W/O CC	0.6236	22.7	18.9
20	NERVOUS SYSTEM INFECTION EXCEPT VIRAL MENINGITIS	1.0097	24.8	20.6
21	VIRAL MENINGITIS [2]	0.7372	23.5	19.5
22	HYPERTENSIVE ENCEPHALOPATHY [2]	0.7372	23.5	19.5
23	NONTRAUMATIC STUPOR & COMA	0.9033	28.8	24.0
24	SEIZURE & HEADACHE AGE >17 W CC	0.8527	26.2	21.8
25	SEIZURE & HEADACHE AGE >17 W/O CC	0.7727	24.1	20.0
26	SEIZURE & HEADACHE AGE 0–17 [8]	0.7372	23.5	19.5
27	TRAUMATIC STUPOR & COMA, COMA >1 HR	1.1929	30.4	25.3
28	TRAUMATIC STUPOR & COMA, COMA <1 HR AGE >17 W CC	1.0211	29.0	24.1
29	TRAUMATIC STUPOR & COMA, COMA <1 HR AGE >17 W/O CC	0.9056	26.6	22.1
30	TRAUMATIC STUPOR & COMA, COMA <1 HR AGE 0–17 [8]	0.9562	26.1	21.7
31	CONCUSSION AGE >17 W CC [7]	0.9562	26.1	21.7
32	CONCUSSION AGE >17 W/O CC [7]	0.9562	26.1	21.7
33	CONCUSSION AGE 0–17 [8]	0.7372	23.5	19.5
34	OTHER DISORDERS OF NERVOUS SYSTEM W CC	0.9140	27.8	23.1
35	OTHER DISORDERS OF NERVOUS SYSTEM W/O CC	0.6651	24.5	20.4
36	RETINAL PROCEDURES [8]	0.4964	18.5	15.4
37	ORBITAL PROCEDURES [8]	0.4964	18.5	15.4
38	PRIMARY IRIS PROCEDURES [8]	0.4964	18.5	15.4
39	LENS PROCEDURES WITH OR WITHOUT VITRECTOMY [8]	0.4964	18.5	15.4
40	EXTRAOCULAR PROCEDURES EXCEPT ORBIT AGE >17 [5]	2.0841	40.0	33.3
41	EXTRAOCULAR PROCEDURES EXCEPT ORBIT AGE 0–17 [8]	0.4964	18.5	15.4
42	INTRAOCULAR PROCEDURES EXCEPT RETINA, IRIS & LENS [8]	0.4964	18.5	15.4
43	HYPHEMA [8]	0.4964	18.5	15.4
44	ACUTE MAJOR EYE INFECTIONS [1]	0.4964	18.5	15.4
45	NEUROLOGICAL EYE DISORDERS [8]	0.4964	18.5	15.4
46	OTHER DISORDERS OF THE EYE AGE >17 W CC [1]	0.4964	18.5	15.4
47	OTHER DISORDERS OF THE EYE AGE >17 W/O CC [1]	0.4964	18.5	15.4
48	OTHER DISORDERS OF THE EYE AGE 0–17 [8]	0.4964	18.5	15.4
49	MAJOR HEAD & NECK PROCEDURES [8]	1.3569	32.5	27.0
50	SIALOADENECTOMY [8]	0.9562	26.1	21.7
51	SALIVARY GLAND PROCEDURES EXCEPT SIALOADENECTOMY [8]	0.9562	26.1	21.7
52	CLEFT LIP & PALATE REPAIR [8]	0.9562	26.1	21.7
53	SINUS & MASTOID PROCEDURES AGE >17 [2]	0.7372	23.5	19.5
54	SINUS & MASTOID PROCEDURES AGE 0–17 [8]	0.9562	26.1	21.7
55	MISCELLANEOUS EAR, NOSE, MOUTH & THROAT PROCEDURES [8]	0.9562	26.1	21.7
56	RHINOPLASTY [8]	0.7372	23.5	19.5
57	T&A PROC, EXCEPT TONSILLECTOMY &/OR ADENOIDECTOMY ONLY, AGE >17 [8].	0.9562	26.1	21.7
58	T&A PROC, EXCEPT TONSILLECTOMY &/OR ADENOIDECTOMY ONLY, AGE 0–17 [8].	0.9562	26.1	21.7
59	TONSILLECTOMY &/OR ADENOIDECTOMY ONLY, AGE >17 [8]	0.9562	26.1	21.7
60	TONSILLECTOMY &/OR ADENOIDECTOMY ONLY, AGE 0–17 [8]	0.9562	26.1	21.7
61	MYRINGOTOMY W TUBE INSERTION AGE >17 [2]	0.7372	23.5	19.5
62	MYRINGOTOMY W TUBE INSERTION AGE 0–17 [8]	0.9562	26.1	21.7
63	OTHER EAR, NOSE, MOUTH & THROAT O.R. PROCEDURES [3]	0.9562	26.1	21.7
64	EAR, NOSE, MOUTH & THROAT MALIGNANCY	1.2540	27.5	22.9
65	DYSEQUILIBRIUM [1]	0.4964	18.5	15.4
66	EPISTAXIS [1]	0.4964	18.5	15.4
67	EPIGLOTTITIS [8]	0.9562	26.1	21.7
68	OTITIS MEDIA & URI AGE >17 W CC	0.8243	21.9	18.2

TABLE 3.—PROPOSED FEDERAL FY 2004 LTC–DRG RELATIVE WEIGHTS, GEOMETRIC MEAN LENGTH OF STAY, AND SHORT-STAYS OF FIVE-SIXTHS AVERAGE LENGTH OF STAY FOR DISCHARGES OCCURRING FROM OCTOBER 1, 2003 THROUGH SEPTEMBER 30, 2004—Continued

LTC–DRG	Description	Relative weight	Geometric average length of stay	5/6th of the average length of stay
69	OTITIS MEDIA & URI AGE >17 W/O CC [1]	0.4964	18.5	15.4
70	OTITIS MEDIA & URI AGE 0–17 [8]	0.4964	18.5	15.4
71	LARYNGOTRACHEITIS [8]	0.4964	18.5	15.4
72	NASAL TRAUMA & DEFORMITY [2]	0.7372	23.5	19.5
73	OTHER EAR, NOSE, MOUTH & THROAT DIAGNOSES AGE >17	0.7215	20.3	16.9
74	OTHER EAR, NOSE, MOUTH & THROAT DIAGNOSES AGE 0–17 [8]	0.4964	18.5	15.4
75	MAJOR CHEST PROCEDURES [5]	2.0841	40.0	33.3
76	OTHER RESP SYSTEM O.R. PROCEDURES W CC	2.4382	43.9	36.5
77	OTHER RESP SYSTEM O.R. PROCEDURES W/O CC [5]	2.0841	40.0	33.3
78	PULMONARY EMBOLISM	0.8896	24.2	20.1
79	RESPIRATORY INFECTIONS & INFLAMMATIONS AGE >17 W CC	0.8985	22.6	18.8
80	RESPIRATORY INFECTIONS & INFLAMMATIONS AGE >17 W/O CC	0.7645	22.3	18.5
81	RESPIRATORY INFECTIONS & INFLAMMATIONS AGE 0–17 [8]	0.4964	18.5	15.4
82	RESPIRATORY NEOPLASMS	0.7480	20.3	16.9
83	MAJOR CHEST TRAUMA W CC [3]	0.9562	26.1	21.7
84	MAJOR CHEST TRAUMA W/O CC [2]	0.7372	23.5	19.5
85	PLEURAL EFFUSION W CC	0.8514	23.5	19.5
86	PLEURAL EFFUSION W/O CC	0.6540	22.4	18.6
87	PULMONARY EDEMA & RESPIRATORY FAILURE	1.6513	31.9	26.5
88	CHRONIC OBSTRUCTIVE PULMONARY DISEASE	0.7653	20.7	17.2
89	SIMPLE PNEUMONIA & PLEURISY AGE >17 W CC	0.8428	23.1	19.2
90	SIMPLE PNEUMONIA & PLEURISY AGE >17 W/O CC	0.7318	21.7	18.0
91	SIMPLE PNEUMONIA & PLEURISY AGE 0–17 [8]	0.7372	23.5	19.5
92	INTERSTITIAL LUNG DISEASE W CC	0.7702	20.4	17.0
93	INTERSTITIAL LUNG DISEASE W/O CC [1]	0.4964	18.5	15.4
94	PNEUMOTHORAX W CC	0.6571	18.9	15.7
95	PNEUMOTHORAX W/O CC [1]	0.4964	18.5	15.4
96	BRONCHITIS & ASTHMA AGE >17 W CC	0.7381	20.5	17.0
97	BRONCHITIS & ASTHMA AGE >17 W/O CC	0.5296	18.7	15.5
98	BRONCHITIS & ASTHMA AGE 0–17 [8]	0.4964	18.5	15.4
99	RESPIRATORY SIGNS & SYMPTOMS W CC	1.0622	26.6	22.1
100	RESPIRATORY SIGNS & SYMPTOMS W/O CC	1.0579	26.1	21.7
101	OTHER RESPIRATORY SYSTEM DIAGNOSES W CC	0.9009	22.6	18.8
102	OTHER RESPIRATORY SYSTEM DIAGNOSES W/O CC	0.7011	21.0	17.5
103	HEART TRANSPLANT [6]	0.0000	0.0	0.0
104	CARDIAC VALVE & OTHER MAJOR CARDIOTHORACIC PROC W CARDIAC CATH [8].	2.0841	40.0	33.3
105	CARDIAC VALVE & OTHER MAJOR CARDIOTHORACIC PROC W/O CARDIAC CATH [8].	2.0841	40.0	33.3
106	CORONARY BYPASS W PTCA [8]	2.0841	40.0	33.3
107	CORONARY BYPASS W CARDIAC CATH [8]	2.0841	40.0	33.3
108	OTHER CARDIOTHORACIC PROCEDURES [5]	2.0841	40.0	33.3
109	CORONARY BYPASS W/O PTCA OR CARDIAC CATH [8]	2.0841	40.0	33.3
110	MAJOR CARDIOVASCULAR PROCEDURES W CC [5]	2.0841	40.0	33.3
111	MAJOR CARDIOVASCULAR PROCEDURES W/O CC [8]	2.0841	40.0	33.3
113	AMPUTATION FOR CIRC SYSTEM DISORDERS EXCEPT UPPER LIMB & TOE	1.5629	38.7	32.2
114	UPPER LIMB & TOE AMPUTATION FOR CIRC SYSTEM DISORDERS	1.3604	38.3	31.9
115	PRM CARD PACEM IMPL W AMI,HRT FAIL OR SHK,OR AICD LEAD OR GNRTR P [5].	2.0841	40.0	33.3
116	OTH PERM CARD PACEMAK IMPL OR PTCA W CORONARY ARTERY STENT IMPLNT [5].	2.0841	40.0	33.3
117	CARDIAC PACEMAKER REVISION EXCEPT DEVICE REPLACEMENT [3]	0.9562	26.1	21.7
118	CARDIAC PACEMAKER DEVICE REPLACEMENT [5]	2.0841	40.0	33.3
119	VEIN LIGATION & STRIPPING [4]	1.3569	32.5	27.0
120	OTHER CIRCULATORY SYSTEM O.R. PROCEDURES	1.2435	34.4	28.6
121	CIRCULATORY DISORDERS W AMI & MAJOR COMP, DISCHARGED ALIVE	0.7467	22.1	18.4
122	CIRCULATORY DISORDERS W AMI W/O MAJOR COMP, DISCHARGED ALIVE	0.6440	18.8	15.6
123	CIRCULATORY DISORDERS W AMI, EXPIRED	0.8527	18.8	15.6
124	CIRCULATORY DISORDERS EXCEPT AMI, W CARD CATH & COMPLEX DIAG [4]	1.3569	32.5	27.0
125	CIRCULATORY DISORDERS EXCEPT AMI, W CARD CATH W/O COMPLEX DIAG [4]	1.3569	32.5	27.0
126	ACUTE & SUBACUTE ENDOCARDITIS	0.8706	25.6	21.3
127	HEART FAILURE & SHOCK	0.7719	22.1	18.4
128	DEEP VEIN THROMBOPHLEBITIS [2]	0.7372	23.5	19.5
129	CARDIAC ARREST, UNEXPLAINED [3]	0.9562	26.1	21.7
130	PERIPHERAL VASCULAR DISORDERS W CC	0.7712	24.4	20.3
131	PERIPHERAL VASCULAR DISORDERS W/O CC	0.6398	23.1	19.2
132	ATHEROSCLEROSIS W CC	0.8092	22.4	18.6

TABLE 3.—PROPOSED FEDERAL FY 2004 LTC–DRG RELATIVE WEIGHTS, GEOMETRIC MEAN LENGTH OF STAY, AND SHORT-STAYS OF FIVE-SIXTHS AVERAGE LENGTH OF STAY FOR DISCHARGES OCCURRING FROM OCTOBER 1, 2003 THROUGH SEPTEMBER 30, 2004—Continued

LTC–DRG	Description	Relative weight	Geometric average length of stay	5/6th of the average length of stay
133	ATHEROSCLEROSIS W/O CC	0.7044	21.9	18.2
134	HYPERTENSION	0.9154	27.9	23.2
135	CARDIAC CONGENITAL & VALVULAR DISORDERS AGE >17 W CC	0.9039	23.1	19.2
136	CARDIAC CONGENITAL & VALVULAR DISORDERS AGE >17 W/O CC	0.7186	22.4	18.6
137	CARDIAC CONGENITAL & VALVULAR DISORDERS AGE 0–17 [8]	0.7372	23.5	19.5
138	CARDIAC ARRHYTHMIA & CONDUCTION DISORDERS W CC	0.7430	22.7	18.9
139	CARDIAC ARRHYTHMIA & CONDUCTION DISORDERS W/O CC	0.6032	20.3	16.9
140	ANGINA PECTORIS	0.6094	19.3	16.0
141	SYNCOPE & COLLAPSE W CC	0.6453	22.9	19.0
142	SYNCOPE & COLLAPSE W/O CC	0.5041	20.3	16.9
143	CHEST PAIN	0.7314	21.8	18.1
144	OTHER CIRCULATORY SYSTEM DIAGNOSES W CC	0.7921	22.2	18.5
145	OTHER CIRCULATORY SYSTEM DIAGNOSES W/O CC	0.6983	20.7	17.2
146	RECTAL RESECTION W CC [8]	2.0841	40.0	33.3
147	RECTAL RESECTION W/O CC [8]	2.0841	40.0	33.3
148	MAJOR SMALL & LARGE BOWEL PROCEDURES W CC [5]	2.0841	40.0	33.3
149	MAJOR SMALL & LARGE BOWEL PROCEDURES W/O CC [1]	0.4964	18.5	15.4
150	PERITONEAL ADHESIOLYSIS W CC [4]	1.3569	32.5	27.0
151	PERITONEAL ADHESIOLYSIS W/O CC [8]	1.3569	32.5	27.0
152	MINOR SMALL & LARGE BOWEL PROCEDURES W CC [4]	1.3569	32.5	27.0
153	MINOR SMALL & LARGE BOWEL PROCEDURES W/O CC [8]	1.3569	32.5	27.0
154	STOMACH, ESOPHAGEAL & DUODENAL PROCEDURES AGE >17 W CC [5]	2.0841	40.0	33.3
155	STOMACH, ESOPHAGEAL & DUODENAL PROCEDURES AGE >17 W/O CC [8]	1.3569	32.5	27.0
156	STOMACH, ESOPHAGEAL & DUODENAL PROCEDURES AGE 0–17 [8]	1.3569	32.5	27.0
157	ANAL & STOMAL PROCEDURES W CC [4]	1.3569	32.5	27.0
158	ANAL & STOMAL PROCEDURES W/O CC [3]	0.9562	26.1	21.7
159	HERNIA PROCEDURES EXCEPT INGUINAL & FEMORAL AGE >17 W CC [8]	1.3569	32.5	27.0
160	HERNIA PROCEDURES EXCEPT INGUINAL & FEMORAL AGE >17 W/O CC [8]	1.3569	32.5	27.0
161	INGUINAL & FEMORAL HERNIA PROCEDURES AGE >17 W CC [4]	1.3569	32.5	27.0
162	INGUINAL & FEMORAL HERNIA PROCEDURES AGE >17 W/O CC [8]	0.4964	18.5	15.4
163	HERNIA PROCEDURES AGE 0–17 [8]	0.4964	18.5	15.4
164	APPENDECTOMY W COMPLICATED PRINCIPAL DIAG WCC [8]	2.0841	40.0	33.3
165	APPENDECTOMY W COMPLICATED PRINCIPAL DIAG W/O CC [8]	0.4964	18.5	15.4
166	APPENDECTOMY W/O COMPLICATED PRINCIPAL DIAG W CC [8]	2.0841	40.0	33.3
167	APPENDECTOMY W/O COMPLICATED PRINCIPAL DIAG W/O CC [8]	0.4964	18.5	15.4
168	MOUTH PROCEDURES W CC [5]	2.0841	40.0	33.3
169	MOUTH PROCEDURES W/O CC [8]	0.7372	23.5	19.5
170	OTHER DIGESTIVE SYSTEM O.R. PROCEDURES W CC	1.7006	40.3	33.5
171	OTHER DIGESTIVE SYSTEM O.R. PROCEDURES W/O CC [4]	1.3569	32.5	27.0
172	DIGESTIVE MALIGNANCY W CC	0.8702	22.5	18.7
173	DIGESTIVE MALIGNANCY W/O CC	0.7092	20.2	16.8
174	G.I. HEMORRHAGE W CC	0.7874	23.7	19.7
175	G.I. HEMORRHAGE W/O CC	0.6345	21.1	17.5
176	COMPLICATED PEPTIC ULCER	0.7728	21.2	17.6
177	UNCOMPLICATED PEPTIC ULCER W CC [2]	0.7372	23.5	19.5
178	UNCOMPLICATED PEPTIC ULCER W/O CC [1]	0.4964	18.5	15.4
179	INFLAMMATORY BOWEL DISEASE	1.0023	25.2	21.0
180	G.I. OBSTRUCTION W CC [7]	0.8222	22.9	19.0
181	G.I. OBSTRUCTION W/O CC [7]	0.8222	22.9	19.0
182	ESOPHAGITIS, GASTROENT & MISC DIGEST DISORDERS AGE >17 W CC	0.8449	23.5	19.5
183	ESOPHAGITIS, GASTROENT & MISC DIGEST DISORDERS AGE >17 W/O CC	0.6362	20.3	16.9
184	ESOPHAGITIS, GASTROENT & MISC DIGEST DISORDERS AGE 0–17 [8]	0.7372	23.5	19.5
185	DENTAL & ORAL DIS EXCEPT EXTRACTIONS & RESTORATIONS, AGE >17 [2]	0.7372	23.5	19.5
186	DENTAL & ORAL DIS EXCEPT EXTRACTIONS & RESTORATIONS, AGE 0–17 [8]	0.7372	23.5	19.5
187	DENTAL EXTRACTIONS & RESTORATIONS [8]	0.7372	23.5	19.5
188	OTHER DIGESTIVE SYSTEM DIAGNOSES AGE >17 W CC	1.0308	25.3	21.0
189	OTHER DIGESTIVE SYSTEM DIAGNOSES AGE >17 W/O CC	0.7826	21.8	18.1
190	OTHER DIGESTIVE SYSTEM DIAGNOSES AGE 0–17 [8]	0.7372	23.5	19.5
191	PANCREAS, LIVER & SHUNT PROCEDURES W CC [4]	1.3569	32.5	27.0
192	PANCREAS, LIVER & SHUNT PROCEDURES W/O CC [1]	0.4964	18.5	15.4
193	BILIARY TRACT PROC EXCEPT ONLY CHOLECYST W OR W/O C.D.E. W CC [2]	0.7372	23.5	19.5
194	BILIARY TRACT PROC EXCEPT ONLY CHOLECYST W OR W/O C.D.E. W/O CC [3]	0.7372	23.5	19.5
195	CHOLECYSTECTOMY W C.D.E. W CC [4]	1.3569	32.5	27.0
196	CHOLECYSTECTOMY W C.D.E. W/O CC [8]	0.9562	26.1	21.7
197	CHOLECYSTECTOMY EXCEPT BY LAPAROSCOPE W/O C.D.E. W CC [3]	0.9562	26.1	21.7
198	CHOLECYSTECTOMY EXCEPT BY LAPAROSCOPE W/O C.D.E. W/O CC [8]	0.9562	26.1	21.7
199	HEPATOBILIARY DIAGNOSTIC PROCEDURE FOR MALIGNANCY [8]	0.7372	23.5	19.5

TABLE 3.—PROPOSED FEDERAL FY 2004 LTC–DRG RELATIVE WEIGHTS, GEOMETRIC MEAN LENGTH OF STAY, AND SHORT-STAYS OF FIVE-SIXTHS AVERAGE LENGTH OF STAY FOR DISCHARGES OCCURRING FROM OCTOBER 1, 2003 THROUGH SEPTEMBER 30, 2004—Continued

LTC–DRG	Description	Relative weight	Geometric average length of stay	5/6th of the average length of stay
200	HEPATOBILIARY DIAGNOSTIC PROCEDURE FOR NON-MALIGNANCY [2]	0.7372	23.5	19.5
201	OTHER HEPATOBILIARY OR PANCREAS O.R. PROCEDURES [5]	2.0841	40.0	33.3
202	CIRRHOSIS & ALCOHOLIC HEPATITIS	0.7254	22.3	18.5
203	MALIGNANCY OF HEPATOBILIARY SYSTEM OR PANCREAS	0.6758	18.9	15.7
204	DISORDERS OF PANCREAS EXCEPT MALIGNANCY	0.9986	23.4	19.5
205	DISORDERS OF LIVER EXCEPT MALIG,CIRR,ALC HEPA W CC [7]	0.7029	22.1	18.4
206	DISORDERS OF LIVER EXCEPT MALIG,CIRR,ALC HEPA W/O CC [7]	0.7029	22.1	18.4
207	DISORDERS OF THE BILIARY TRACT W CC [7]	0.6671	20.5	17.0
208	DISORDERS OF THE BILIARY TRACT W/O CC [7]	0.6671	20.5	17.0
209	MAJOR JOINT & LIMB REATTACHMENT PROCEDURES OF LOWER EXTREMITY [4]	1.3569	32.5	27.0
210	HIP & FEMUR PROCEDURES EXCEPT MAJOR JOINT AGE >17 W CC [4]	1.3569	32.5	27.0
211	HIP & FEMUR PROCEDURES EXCEPT MAJOR JOINT AGE >17 W/O CC [2]	0.7372	23.5	19.5
212	HIP & FEMUR PROCEDURES EXCEPT MAJOR JOINT AGE 0–17 [8]	0.7372	23.5	19.5
213	AMPUTATION FOR MUSCULOSKELETAL SYSTEM & CONN TISSUE DISORDERS	1.3851	33.8	28.1
216	BIOPSIES OF MUSCULOSKELETAL SYSTEM & CONNECTIVE TISSUE [4]	1.3569	32.5	27.0
217	WND DEBRID & SKN GRFT EXCEPT HAND,FOR MUSCSKELET & CONN TISS DIS	1.4038	39.3	32.7
218	LOWER EXTREM & HUMER PROC EXCEPT HIP,FOOT,FEMUR AGE >17 W CC [3]	0.9562	26.1	21.7
219	LOWER EXTREM & HUMER PROC EXCEPT HIP,FOOT,FEMUR AGE >17 W/O CC [8]	0.9562	26.1	21.7
220	LOWER EXTREM & HUMER PROC EXCEPT HIP,FOOT,FEMUR AGE 0–17 [8]	0.9562	26.1	21.7
223	MAJOR SHOULDER/ELBOW PROC, OR OTHER UPPER EXTREMITY PROC W CC [3].	0.9562	26.1	21.7
224	SHOULDER,ELBOW OR FOREARM PROC,EXC MAJOR JOINT PROC, W/O CC [8]	0.9562	26.1	21.7
225	FOOT PROCEDURES [3]	0.9562	26.1	21.7
226	SOFT TISSUE PROCEDURES W CC [7]	1.3569	32.5	27.0
227	SOFT TISSUE PROCEDURES W/O CC [7]	1.3569	32.5	27.0
228	MAJOR THUMB OR JOINT PROC,OR OTH HAND OR WRIST PROC W CC [4]	1.3569	32.5	27.0
229	HAND OR WRIST PROC, EXCEPT MAJOR JOINT PROC, W/O CC [8]	0.9562	26.1	21.7
230	LOCAL EXCISION & REMOVAL OF INT FIX DEVICES OF HIP & FEMUR [4]	1.3569	32.5	27.0
232	ARTHROSCOPY [2]	0.7372	23.5	19.5
233	OTHER MUSCULOSKELET SYS & CONN TISS O.R. PROC W CC [3]	0.9562	26.1	21.7
234	OTHER MUSCULOSKELET SYS & CONN TISS O.R. PROC W/O CC [3]	0.9562	26.1	21.7
235	FRACTURES OF FEMUR	0.8396	29.6	24.6
236	FRACTURES OF HIP & PELVIS	0.7368	27.1	22.5
237	SPRAINS, STRAINS, & DISLOCATIONS OF HIP, PELVIS & THIGH [2]	0.7372	23.5	19.5
238	OSTEOMYELITIS	0.8432	27.9	23.2
239	PATHOLOGICAL FRACTURES & MUSCULOSKELETAL & CONN TISS MALIGNANCY.	0.6610	22.0	18.3
240	CONNECTIVE TISSUE DISORDERS W CC	0.6685	21.2	17.6
241	CONNECTIVE TISSUE DISORDERS W/O CC	0.4538	18.7	15.5
242	SEPTIC ARTHRITIS	0.7721	26.4	22.0
243	MEDICAL BACK PROBLEMS	0.6616	23.2	19.3
244	BONE DISEASES & SPECIFIC ARTHROPATHIES W CC	0.5563	20.0	16.6
245	BONE DISEASES & SPECIFIC ARTHROPATHIES W/O CC	0.4721	18.5	15.4
246	NON-SPECIFIC ARTHROPATHIES	0.5128	22.2	18.5
247	SIGNS & SYMPTOMS OF MUSCULOSKELETAL SYSTEM & CONN TISSUE	0.5536	20.2	16.8
248	TENDONITIS, MYOSITIS & BURSITIS	0.7274	24.5	20.4
249	AFTERCARE, MUSCULOSKELETAL SYSTEM & CONNECTIVE TISSUE	0.7829	27.0	22.5
250	FX, SPRN, STRN & DISL OF FOREARM, HAND, FOOT AGE >17 W CC	0.8206	29.9	24.9
251	FX, SPRN, STRN & DISL OF FOREARM, HAND, FOOT AGE >17 W/O CC	0.6009	27.3	22.7
252	FX, SPRN, STRN & DISL OF FOREARM, HAND, FOOT AGE 0–17 [8]	0.9562	26.1	21.7
253	FX, SPRN, STRN & DISL OF UPARM, LOWLEG EX FOOT AGE >17 W CC	0.8176	27.6	23.0
254	FX, SPRN, STRN & DISL OF UPARM, LOWLEG EX FOOT AGE >17 W/O CC	0.6691	25.1	20.9
255	FX, SPRN, STRN & DISL OF UPARM, LOWLEG EX FOOT AGE 0–17 [8]	0.9562	26.1	21.7
256	OTHER MUSCULOSKELETAL SYSTEM & CONNECTIVE TISSUE DIAGNOSES	0.8294	25.9	21.5
257	TOTAL MASTECTOMY FOR MALIGNANCY W CC [3]	0.9562	26.1	21.7
258	TOTAL MASTECTOMY FOR MALIGNANCY W/O CC [8]	0.9562	26.1	21.7
259	SUBTOTAL MASTECTOMY FOR MALIGNANCY W CC [8]	0.9562	26.1	21.7
260	SUBTOTAL MASTECTOMY FOR MALIGNANCY W/O CC [8]	0.9562	26.1	21.7
261	BREAST PROC FOR NON-MALIGNANCY EXCEPT BIOPSY & LOCAL EXCISION [5]	2.0841	40.0	33.3
262	BREAST BIOPSY & LOCAL EXCISION FOR NON-MALIGNANCY [3]	0.9562	26.1	21.7
263	SKIN GRAFT &/OR DEBRID FOR SKN ULCER OR CELLULITIS W CC	1.4522	42.4	35.3
264	SKIN GRAFT &/OR DEBRID FOR SKN ULCER OR CELLULITIS W/O CC	1.2892	44.1	36.7
265	SKIN GRAFT &/OR DEBRID EXCEPT FOR SKIN ULCER OR CELLULITIS W CC [7]	1.2215	34.8	29.0
266	SKIN GRAFT &/OR DEBRID EXCEPT FOR SKIN ULCER OR CELLULITIS W/O CC [7]	1.2215	34.8	29.0
267	PERIANAL & PILONIDAL PROCEDURES [8]	0.9562	26.1	21.7
268	SKIN, SUBCUTANEOUS TISSUE & BREAST PLASTIC PROCEDURES [5]	2.0841	40.0	33.3
269	OTHER SKIN, SUBCUT TISS & BREAST PROC W CC	1.4466	43.0	35.8

TABLE 3.—PROPOSED FEDERAL FY 2004 LTC–DRG RELATIVE WEIGHTS, GEOMETRIC MEAN LENGTH OF STAY, AND SHORT-STAYS OF FIVE-SIXTHS AVERAGE LENGTH OF STAY FOR DISCHARGES OCCURRING FROM OCTOBER 1, 2003 THROUGH SEPTEMBER 30, 2004—Continued

LTC–DRG	Description	Relative weight	Geometric average length of stay	5/6th of the average length of stay
270	OTHER SKIN, SUBCUT TISS & BREAST PROC W/O CC	0.9916	33.9	28.2
271	SKIN ULCERS	0.9620	30.4	25.3
272	MAJOR SKIN DISORDERS W CC	0.7121	22.8	19.0
273	MAJOR SKIN DISORDERS W/O CC [1]	0.4964	18.5	15.4
274	MALIGNANT BREAST DISORDERS W CC	0.9072	24.9	20.7
275	MALIGNANT BREAST DISORDERS W/O CC [2]	0.7372	23.5	19.5
276	NON-MALIGNANT BREAST DISORDERS [1]	0.4964	18.5	15.4
277	CELLULITIS AGE >17 W CC	0.7409	23.6	19.6
278	CELLULITIS AGE >17 W/O CC	0.5982	20.7	17.2
279	CELLULITIS AGE 0–17 [8]	0.9562	26.1	21.7
280	TRAUMA TO THE SKIN, SUBCUT TISS & BREAST AGE >17 W CC	0.9724	29.5	24.5
281	TRAUMA TO THE SKIN, SUBCUT TISS & BREAST AGE >17 W/O CC	0.7386	26.4	22.0
282	TRAUMA TO THE SKIN, SUBCUT TISS & BREAST AGE 0–17	0.7372	23.5	19.5
283	MINOR SKIN DISORDERS W CC [8]	0.6508	19.3	16.0
284	MINOR SKIN DISORDERS W/O CC [1]	0.4964	18.5	15.4
285	AMPUTAT OF LOWER LIMB FOR ENDOCRINE, NUTRIT,& METABOL DISORDERS	1.5176	37.4	31.1
286	ADRENAL & PITUITARY PROCEDURES [8]	0.7372	23.5	19.5
287	SKIN GRAFTS & WOUND DEBRID FOR ENDOC, NUTRIT & METAB DISORDERS	1.3982	39.7	33.0
288	O.R. PROCEDURES FOR OBESITY [5]	2.0841	40.0	33.3
289	PARATHYROID PROCEDURES [8]	0.7372	23.5	19.5
290	THYROID PROCEDURES [8]	0.7372	23.5	19.5
291	THYROGLOSSAL PROCEDURES [8]	0.7372	23.5	19.5
292	OTHER ENDOCRINE, NUTRIT & METAB O.R. PROC W CC [4]	1.3569	32.5	27.0
293	OTHER ENDOCRINE, NUTRIT & METAB O.R. PROC W/O CC [8]	0.9562	26.1	21.7
294	DIABETES AGE >35	0.8061	25.9	21.5
295	DIABETES AGE 0–35 [3]	0.9562	26.1	21.7
296	NUTRITIONAL & MISC METABOLIC DISORDERS AGE >17 W CC	0.8207	24.1	20.0
297	NUTRITIONAL & MISC METABOLIC DISORDERS AGE >17 W/O CC	0.6524	24.5	20.4
298	NUTRITIONAL & MISC METABOLIC DISORDERS AGE 0–17 [8]	0.7372	23.5	19.5
299	INBORN ERRORS OF METABOLISM [3]	0.9562	26.1	21.7
300	ENDOCRINE DISORDERS W CC	0.7704	22.3	18.5
301	ENDOCRINE DISORDERS W/O CC [2]	0.7372	23.5	19.5
302	KIDNEY TRANSPLANT [6]	0.0000	0.0	0.0
303	KIDNEY,URETER & MAJOR BLADDER PROCEDURES FOR NEOPLASM [8]	2.0841	40.0	33.3
304	KIDNEY,URETER & MAJOR BLADDER PROC FOR NON-NEOPL W CC [5]	2.0841	40.0	33.3
305	KIDNEY,URETER & MAJOR BLADDER PROC FOR NON-NEOPL W/O CC [1]	0.4964	18.5	15.4
306	PROSTATECTOMY W CC [8]	1.3569	32.5	27.0
307	PROSTATECTOMY W/O CC [8]	1.3569	32.5	27.0
308	MINOR BLADDER PROCEDURES W CC [4]	1.3569	32.5	27.0
309	MINOR BLADDER PROCEDURES W/O CC [2]	0.7372	23.5	19.5
310	TRANSURETHRAL PROCEDURES W CC [4]	1.3569	32.5	27.0
311	TRANSURETHRAL PROCEDURES W/O CC [1]	0.4964	18.5	15.4
312	URETHRAL PROCEDURES, AGE >17 W CC [4]	1.3569	32.5	27.0
313	URETHRAL PROCEDURES, AGE >17 W/O CC [8]	0.4964	18.5	15.4
314	URETHRAL PROCEDURES, AGE 0–17 [8]	0.4964	18.5	15.4
315	OTHER KIDNEY & URINARY TRACT O.R. PROCEDURES	1.5070	36.8	30.6
316	RENAL FAILURE	0.9214	23.8	19.8
317	ADMIT FOR RENAL DIALYSIS [3]	0.9562	26.1	21.7
318	KIDNEY & URINARY TRACT NEOPLASMS W CC	0.7048	21.1	17.5
319	KIDNEY & URINARY TRACT NEOPLASMS W/O CC [1]	0.4964	18.5	15.4
320	KIDNEY & URINARY TRACT INFECTIONS AGE >17 W CC	0.7223	23.0	19.1
321	KIDNEY & URINARY TRACT INFECTIONS AGE >17 W/O CC	0.6260	23.2	19.3
322	KIDNEY & URINARY TRACT INFECTIONS AGE 0–17 [8]	0.4964	18.5	15.4
323	URINARY STONES W CC, &/OR ESW LITHOTRIPSY [2]	0.7372	23.5	19.5
324	URINARY STONES W/O CC [2]	0.7372	23.5	19.5
325	KIDNEY & URINARY TRACT SIGNS & SYMPTOMS AGE >17 W CC [3]	0.9562	26.1	21.7
326	KIDNEY & URINARY TRACT SIGNS & SYMPTOMS AGE >17 W/O CC [1]	0.4964	18.5	15.4
327	KIDNEY & URINARY TRACT SIGNS & SYMPTOMS AGE 0–17 [8]	0.4964	18.5	15.4
328	URETHRAL STRICTURE AGE >17 W CC [8]	0.4964	18.5	15.4
329	URETHRAL STRICTURE AGE >17 W/O CC [8]	0.4964	18.5	15.4
330	URETHRAL STRICTURE AGE 0–17 [8]	0.4964	18.5	15.4
331	OTHER KIDNEY & URINARY TRACT DIAGNOSES AGE >17 W/O CC	0.8473	23.2	19.3
332	OTHER KIDNEY & URINARY TRACT DIAGNOSES AGE >17 W/O CC	0.5722	21.1	17.5
333	OTHER KIDNEY & URINARY TRACT DIAGNOSES AGE 0–17 [8]	0.4964	18.5	15.4
334	MAJOR MALE PELVIC PROCEDURES W CC [8]	2.0841	40.0	33.3
335	MAJOR MALE PELVIC PROCEDURES W/O CC [8]	2.0841	40.0	33.3
336	TRANSURETHRAL PROSTATECTOMY W CC [8]	0.7372	23.5	19.5

TABLE 3.—PROPOSED FEDERAL FY 2004 LTC–DRG RELATIVE WEIGHTS, GEOMETRIC MEAN LENGTH OF STAY, AND SHORT-STAYS OF FIVE-SIXTHS AVERAGE LENGTH OF STAY FOR DISCHARGES OCCURRING FROM OCTOBER 1, 2003 THROUGH SEPTEMBER 30, 2004—Continued

LTC–DRG	Description	Relative weight	Geometric average length of stay	5/6th of the average length of stay
337	TRANSURETHRAL PROSTATECTOMY W/O CC [8]	0.7372	23.5	19.5
338	TESTES PROCEDURES, FOR MALIGNANCY [8]	0.7372	23.5	19.5
339	TESTES PROCEDURES, NON-MALIGNANCY AGE >17 [2]	0.7372	23.5	19.5
340	TESTES PROCEDURES, NON-MALIGNANCY AGE 0–17 [8]	0.7372	23.5	19.5
341	PENIS PROCEDURES [2]	0.7372	23.5	19.5
342	CIRCUMCISION AGE >17 [1]	0.4964	18.5	15.4
343	CIRCUMCISION AGE 0–17 [8]	0.7372	23.5	19.5
344	OTHER MALE REPRODUCTIVE SYSTEM O.R. PROCEDURES FOR MALIGNANCY [1].	0.4964	18.5	15.4
345	OTHER MALE REPRODUCTIVE SYSTEM O.R. PROC EXCEPT FOR MALIGNANCY [5].	2.0841	40.0	33.3
346	MALIGNANCY, MALE REPRODUCTIVE SYSTEM, W CC [7]	0.7150	22.3	18.5
347	MALIGNANCY, MALE REPRODUCTIVE SYSTEM, W/O CC [7]	0.7150	22.3	18.5
348	BENIGN PROSTATIC HYPERTROPHY W CC [1]	0.4964	18.5	15.4
349	BENIGN PROSTATIC HYPERTROPHY W/O CC [1]	0.4964	18.5	15.4
350	INFLAMMATION OF THE MALE REPRODUCTIVE SYSTEM	1.1820	26.6	22.1
351	STERILIZATION, MALE [8]	0.7372	23.5	19.5
352	OTHER MALE REPRODUCTIVE SYSTEM DIAGNOSES [3]	0.9562	26.1	21.7
353	PELVIC EVISCERATION, RADICAL HYSTERECTOMY RADICAL VULVECTOMY [8]	2.0841	40.0	33.3
354	UTERINE,ADNEXA PROC FOR NON-OVARIAN/ADNEXAL MALIG W CC [8]	2.0841	40.0	33.3
355	UTERINE,ADNEXA PROC FOR NON-OVARIAN/ADNEXAL MALIG W/O CC [8]	2.0841	40.0	33.3
356	FEMALE REPRODUCTIVE SYSTEM RECONSTRUCTIVE PROCEDURES [8]	1.3569	32.5	27.0
357	UTERINE & ADNEXA PROC FOR OVARIAN OR ADNEXAL MALIGNANCY [8]	1.3569	32.5	27.0
358	UTERINE & ADNEXA PROC FOR NON-MALIGNANCY W CC [8]	1.3569	32.5	27.0
359	UTERINE & ADNEXA PROC FOR NON-MALIGNANCY W/O CC [8]	1.3569	32.5	27.0
360	VAGINA, CERVIX & VULVA PROCEDURES [4]	1.3569	32.5	27.0
361	LAPAROSCOPY & INCISIONAL TUBAL INTERRUPTION [8]	0.4964	18.5	15.4
362	ENDOSCOPIC TUBAL INTERRUPTION [8]	0.4964	18.5	15.4
363	DC, CONIZATION & RADIO-IMPLANT, FOR MALIGNANCY [8]	0.4964	18.5	15.4
364	DC, CONIZATION EXCEPT FOR MALIGNANCY [8]	0.4964	18.5	15.4
365	OTHER FEMALE REPRODUCTIVE SYSTEM O.R. PROCEDURES [5]	2.0841	40.0	33.3
366	MALIGNANCY, FEMALE REPRODUCTIVE SYSTEM W CC	0.8139	23.1	19.2
367	MALIGNANCY, FEMALE REPRODUCTIVE SYSTEM W/O CC [1]	0.4964	18.5	15.4
368	INFECTIONS, FEMALE REPRODUCTIVE SYSTEM	0.6963	19.3	16.0
369	MENSTRUAL & OTHER FEMALE REPRODUCTIVE SYSTEM DISORDERS [3]	0.9562	26.1	21.7
370	CESAREAN SECTION W CC [8]	0.9562	26.1	21.7
371	CESAREAN SECTION W/O CC [8]	0.4964	18.5	15.4
372	VAGINAL DELIVERY W COMPLICATING DIAGNOSES [8]	0.4964	18.5	15.4
373	VAGINAL DELIVERY W/O COMPLICATING DIAGNOSES [8]	0.4964	18.5	15.4
374	VAGINAL DELIVERY W STERILIZATION /OR DaC [8]	0.4964	18.5	15.4
375	VAGINAL DELIVERY W O.R. PROC EXCEPT STERIL /OR DaC [8]	0.4964	18.5	15.4
376	POSTPARTUM & POST ABORTION DIAGNOSES W/O O.R. PROCEDURE [1]	0.4964	18.5	15.4
377	POSTPARTUM & POST ABORTION DIAGNOSES W O.R. PROCEDURE [8]	0.4964	18.5	15.4
378	ECTOPIC PREGNANCY [8]	0.9562	26.1	21.7
379	THREATENED ABORTION [8]	0.4964	18.5	15.4
380	ABORTION W/O D&C [8]	0.4964	18.5	15.4
381	ABORTION W D&C, ASPIRATION CURETTAGE OR HYSTEROTOMY [8]	0.4964	18.5	15.4
382	FALSE LABOR [8]	0.4964	18.5	15.4
383	OTHER ANTEPARTUM DIAGNOSES W MEDICAL COMPLICATIONS [8]	0.4964	18.5	15.4
384	OTHER ANTEPARTUM DIAGNOSES W/O MEDICAL COMPLICATIONS [8]	0.4964	18.5	15.4
385	NEONATES, DIED OR TRANSFERRED TO ANOTHER ACUTE CARE FACILITY [8]	0.4964	18.5	15.4
386	EXTREME IMMATURITY [8]	0.4964	18.5	15.4
387	PREMATURITY W MAJOR PROBLEMS [8]	0.4964	18.5	15.4
388	PREMATURITY W/O MAJOR PROBLEMS [8]	0.4964	18.5	15.4
389	FULL TERM NEONATE W MAJOR PROBLEMS [8]	0.4964	18.5	15.4
390	NEONATE W OTHER SIGNIFICANT PROBLEMS [8]	0.4964	18.5	15.4
391	NORMAL NEWBORN [8]	0.4964	18.5	15.4
392	SPLENECTOMY AGE >17 [8]	0.7372	23.5	19.5
393	SPLENECTOMY AGE 0–17 [8]	0.7372	23.5	19.5
394	OTHER O.R. PROCEDURES OF THE BLOOD AND BLOOD FORMING ORGANS [3]	0.9562	26.1	21.7
395	RED BLOOD CELL DISORDERS AGE >17	0.7782	24.0	20.0
396	RED BLOOD CELL DISORDERS AGE 0–17 [8]	0.4964	18.5	15.4
397	COAGULATION DISORDERS	0.9454	23.5	19.5
398	RETICULOENDOTHELIAL & IMMUNITY DISORDERS W CC	0.8372	22.0	18.3
399	RETICULOENDOTHELIAL & IMMUNITY DISORDERS W/O CC [1]	0.4964	18.5	15.4
401	LYMPHOMA & NON-ACUTE LEUKEMIA W OTHER O.R. PROC W CC [5]	2.0841	40.0	33.3
402	LYMPHOMA & NON-ACUTE LEUKEMIA W OTHER O.R. PROC W/O CC [3]	0.9562	26.1	21.7

TABLE 3.—PROPOSED FEDERAL FY 2004 LTC–DRG RELATIVE WEIGHTS, GEOMETRIC MEAN LENGTH OF STAY, AND SHORT-STAYS OF FIVE-SIXTHS AVERAGE LENGTH OF STAY FOR DISCHARGES OCCURRING FROM OCTOBER 1, 2003 THROUGH SEPTEMBER 30, 2004—Continued

LTC–DRG	Description	Relative weight	Geometric average length of stay	5/6th of the average length of stay
403	LYMPHOMA & NON-ACUTE LEUKEMIA W CC	0.8941	22.4	18.6
404	LYMPHOMA & NON-ACUTE LEUKEMIA W/O CC	0.7394	18.0	15.0
405	ACUTE LEUKEMIA W/O MAJOR O.R. PROCEDURE AGE 0–17 [8]	0.7372	23.5	19.5
406	MYELOPROLIF DISORD OR POORLY DIFF NEOPL W MAJ O.R.PROC W CC [5]	2.0841	40.0	33.3
407	MYELOPROLIF DISORD OR POORLY DIFF NEOPL W MAJ O.R.PROC W/O CC [8]	0.9562	26.1	21.7
408	MYELOPROLIF DISORD OR POORLY DIFF NEOPL W OTHER O.R.PROC [3]	0.9562	26.1	21.7
409	RADIOTHERAPY	0.8871	25.1	20.9
410	CHEMOTHERAPY W/O ACUTE LEUKEMIA AS SECONDARY DIAGNOSIS [3]	0.9562	26.1	21.7
411	HISTORY OF MALIGNANCY W/O ENDOSCOPY [8]	0.4964	18.5	15.4
412	HISTORY OF MALIGNANCY W ENDOSCOPY [8]	0.4964	18.5	15.4
413	OTHER MYELOPROLIF DIS OR POORLY DIFF NEOPL DIAG W CC	0.9541	25.5	21.2
414	OTHER MYELOPROLIF DIS OR POORLY DIFF NEOPL DIAG W/O CC [1]	0.4964	18.5	15.4
415	O.R. PROCEDURE FOR INFECTIOUS & PARASITIC DISEASES	1.6849	40.1	33.4
416	SEPTICEMIA AGE >17	0.9191	24.9	20.7
417	SEPTICEMIA AGE 0–17 [8]	0.9562	26.1	21.7
418	POSTOPERATIVE & POST-TRAUMATIC INFECTIONS	0.8304	25.2	21.0
419	FEVER OF UNKNOWN ORIGIN AGE >17 W CC [3]	0.9562	26.1	21.7
420	FEVER OF UNKNOWN ORIGIN AGE >17 W/O CC [2]	0.7372	23.5	19.5
421	VIRAL ILLNESS AGE >17 [2]	0.7372	23.5	19.5
422	VIRAL ILLNESS & FEVER OF UNKNOWN ORIGIN AGE 0–17 [8]	0.7372	23.5	19.5
423	OTHER INFECTIOUS & PARASITIC DISEASES DIAGNOSES	0.9024	23.1	19.2
424	O.R. PROCEDURE W PRINCIPAL DIAGNOSES OF MENTAL ILLNESS [4]	1.3569	32.5	27.0
425	ACUTE ADJUSTMENT REACTION & PSYCHOLOGICAL DYSFUNCTION	0.5981	27.5	22.9
426	DEPRESSIVE NEUROSES	0.4660	22.3	18.5
427	NEUROSES EXCEPT DEPRESSIVE [4]	1.3569	32.5	27.0
428	DISORDERS OF PERSONALITY & IMPULSE CONTROL [1]	0.4964	18.5	15.4
429	ORGANIC DISTURBANCES & MENTAL RETARDATION	0.6438	27.4	22.8
430	PSYCHOSES	0.4689	22.7	18.9
431	CHILDHOOD MENTAL DISORDERS [1]	0.4964	18.5	15.4
432	OTHER MENTAL DISORDER DIAGNOSES [1]	0.4964	18.5	15.4
433	ALCOHOL/DRUG ABUSE OR DEPENDENCE, LEFT AMA [1]	0.4964	18.5	15.4
439	SKIN GRAFTS FOR INJURIES	1.3663	40.5	33.7
440	WOUND DEBRIDEMENTS FOR INJURIES	1.5854	40.0	33.3
441	HAND PROCEDURES FOR INJURIES [5]	2.0841	40.0	33.3
442	OTHER O.R. PROCEDURES FOR INJURIES W CC	1.4971	44.6	37.1
443	OTHER O.R. PROCEDURES FOR INJURIES W/O CC [4]	1.3569	32.5	27.0
444	TRAUMATIC INJURY AGE >17 W CC	0.9609	30.6	25.5
445	TRAUMATIC INJURY AGE >17 W/O CC	0.7552	26.6	22.1
446	TRAUMATIC INJURY AGE 0–17 [8]	0.7372	23.5	19.5
447	ALLERGIC REACTIONS AGE >17 [3]	0.9562	26.1	21.7
448	ALLERGIC REACTIONS AGE 0–17 [8]	0.7372	23.5	19.5
449	POISONING & TOXIC EFFECTS OF DRUGS AGE >17 W CC [7]	0.9562	26.1	21.7
450	POISONING & TOXIC EFFECTS OF DRUGS AGE >17 W/O CC [7]	0.9562	26.1	21.7
451	POISONING & TOXIC EFFECTS OF DRUGS AGE 0–17 [8]	0.7372	23.5	19.5
452	COMPLICATIONS OF TREATMENT W CC	0.9692	24.9	20.7
453	COMPLICATIONS OF TREATMENT W/O CC	0.8633	24.2	20.1
454	OTHER INJURY, POISONING & TOXIC EFFECT DIAG W CC [2]	0.7372	23.5	19.5
455	OTHER INJURY, POISONING & TOXIC EFFECT DIAG W/O CC [2]	0.7372	23.5	19.5
461	O.R. PROC W DIAGNOSES OF OTHER CONTACT W HEALTH SERVICES	1.3216	36.5	30.4
462	REHABILITATION	0.6471	23.2	19.3
463	SIGNS & SYMPTOMS W CC	0.7541	26.8	22.3
464	SIGNS & SYMPTOMS W/O CC	0.6170	25.5	21.2
465	AFTERCARE W HISTORY OF MALIGNANCY AS SECONDARY DIAGNOSIS [2]	0.7372	23.5	19.5
466	AFTERCARE W/O HISTORY OF MALIGNANCY AS SECONDARY DIAGNOSIS	0.7365	22.0	18.3
467	OTHER FACTORS INFLUENCING HEALTH STATUS [1]	0.4964	18.5	15.4
468	EXTENSIVE O.R. PROCEDURE UNRELATED TO PRINCIPAL DIAGNOSIS	2.0686	42.5	35.4
469	PRINCIPAL DIAGNOSIS INVALID AS DISCHARGE DIAGNOSIS [6]	0.0000	0.0	0.0
470	UNGROUPABLE [6]	0.0000	0.0	0.0
471	BILATERAL OR MULTIPLE MAJOR JOINT PROCS OF LOWER EXTREMITY [5]	2.0841	40.0	33.3
473	ACUTE LEUKEMIA W/O MAJOR O.R. PROCEDURE AGE >17 [3]	0.9562	26.1	21.7
475	RESPIRATORY SYSTEM DIAGNOSIS WITH VENTILATOR SUPPORT	2.1358	35.2	29.3
476	PROSTATIC O.R. PROCEDURE UNRELATED TO PRINCIPAL DIAGNOSIS	1.0032	31.9	26.5
477	NON-EXTENSIVE O.R. PROCEDURE UNRELATED TO PRINCIPAL DIAGNOSIS	1.8998	40.0	33.3
478	OTHER VASCULAR PROCEDURES W CC [7]	1.2567	34.2	28.5
479	OTHER VASCULAR PROCEDURES W/O CC [7]	1.2567	34.2	28.5
480	LIVER TRANSPLANT [6]	0.0000	0.0	0.0
481	BONE MARROW TRANSPLANT [8]	0.9562	26.1	21.7

TABLE 3.—PROPOSED FEDERAL FY 2004 LTC–DRG RELATIVE WEIGHTS, GEOMETRIC MEAN LENGTH OF STAY, AND SHORT-STAYS OF FIVE-SIXTHS AVERAGE LENGTH OF STAY FOR DISCHARGES OCCURRING FROM OCTOBER 1, 2003 THROUGH SEPTEMBER 30, 2004—Continued

LTC–DRG	Description	Relative weight	Geometric average length of stay	5/6th of the average length of stay
482	TRACHEOSTOMY FOR FACE, MOUTH & NECK DIAGNOSES [5]	2.0841	40.0	33.3
483	TRACH W MECH VENT 96+ HRS OR PDX EXCEPT FACE,MOUTH & NECK DIAG	3.2131	55.7	46.4
484	CRANIOTOMY FOR MULTIPLE SIGNIFICANT TRAUMA [8]	2.0841	40.0	33.3
485	LIMB REATTACHMENT, HIP AND FEMUR PROC FOR MULTIPLE SIGNIFICANT TR [8].	1.3569	32.5	27.0
486	OTHER O.R. PROCEDURES FOR MULTIPLE SIGNIFICANT TRAUMA [4]	1.3569	32.5	27.0
487	OTHER MULTIPLE SIGNIFICANT TRAUMA	1.2484	32.7	27.2
488	HIV W EXTENSIVE O.R. PROCEDURE [5]	2.0841	40.0	33.3
489	HIV W MAJOR RELATED CONDITION	0.9254	21.3	17.7
490	HIV W OR W/O OTHER RELATED CONDITION	0.7361	19.6	16.3
491	MAJOR JOINT & LIMB REATTACHMENT PROCEDURES OF UPPER EXTREMITY [8]	1.3569	32.5	27.0
492	CHEMOTHERAPY W ACUTE LEUKEMIA AS SECONDARY DIAGNOSIS OR W USE HIGH DOSE CHEMOTHERAPY AGENT [8].	0.9562	26.1	21.7
493	LAPAROSCOPIC CHOLECYSTECTOMY W/O C.D.E. W CC [7]	1.3569	32.5	27.0
494	LAPAROSCOPIC CHOLECYSTECTOMY W/O C.D.E. W/O CC [7]	2.0841	40.0	33.3
495	LUNG TRANSPLANT [6]	0.0000	0.0	0.0
496	COMBINED ANTERIOR/POSTERIOR SPINAL FUSION [8]	1.3569	32.5	27.0
497	SPINAL FUSION W CC [7]	0.9562	26.1	21.7
498	SPINAL FUSION W/O CC [7]	0.9562	26.1	21.7
499	BACK & NECK PROCEDURES EXCEPT SPINAL FUSION W CC [5]	2.0841	40.0	33.3
500	BACK & NECK PROCEDURES EXCEPT SPINAL FUSION W/O CC [4]	1.3569	32.5	27.0
501	KNEE PROCEDURES W PDX OF INFECTION W CC [5]	2.0841	40.0	33.3
502	KNEE PROCEDURES W PDX OF INFECTION W/O CC [2]	0.7372	23.5	19.5
503	KNEE PROCEDURES W/O PDX OF INFECTION [3]	0.9562	26.1	21.7
504	EXTENSIVE 3RD DEGREE BURNS W SKIN GRAFT [8]	2.0841	40.0	33.3
505	EXTENSIVE 3RD DEGREE BURNS W/O SKIN GRAFT [4]	1.3569	32.5	27.0
506	FULL THICKNESS BURN W SKIN GRAFT OR INHAL INJ W CC OR SIG TRAUMA [7]	0.7372	23.5	19.5
507	FULL THICKNESS BURN W SKIN GRFT OR INHAL INJ W/O CC OR SIG TRAUMA [7]	0.7372	23.5	19.5
508	FULL THICKNESS BURN W/O SKIN GRFT OR INHAL INJ W CC OR SIG TRAUMA [2]	0.7372	23.5	19.5
509	FULL THICKNESS BURN W/O SKIN GRFT OR INH INJ W/O CC OR SIG TRAUMA [2]	0.7372	23.5	19.5
510	NON-EXTENSIVE BURNS W CC OR SIGNIFICANT TRAUMA [2]	0.7372	23.5	19.5
511	NON-EXTENSIVE BURNS W/O CC OR SIGNIFICANT TRAUMA [1]	0.4964	18.5	15.4
512	SIMULTANEOUS PANCREAS/KIDNEY TRANSPLANT [6]	0.0000	0.0	0.0
513	PANCREAS TRANSPLANT [6]	0.0000	0.0	0.0
515	CARDIAC DEFIBRILATOR IMPLANT W/O CARDIAC CATH [5]	2.0841	40.0	33.3
516	PERCUTANEOUS CARDIVASCULAR PROCEDURE W AMI [8]	0.9562	26.1	21.7
517	PERCUTANEOUS CARDIVASCULAR PROC W NON-DRUG ELUTING STENT W/O AMI [4].	1.3569	32.5	27.0
518	PERCUTANEOUS CARDIVASCULAR PROC W/O CORONARY ARTERY STENT OR AMI [3].	0.9562	26.1	21.7
519	CERVICAL SPINAL FUSION W CC [4]	1.3569	32.5	27.0
520	CERVICAL SPINAL FUSION W/O CC [8]	0.9562	26.1	21.7
521	ALCOHOL/DRUG ABUSE OR DEPENDENCE W CC	0.4753	20.5	17.0
522	ALCOHOL/DRUG ABUSE OR DEPENDENCE W REHABILITATION THERAPY W/O CC.	0.4061	20.4	17.0
523	ALCOHOL/DRUG ABUSE OR DEPENDENCE W/O REHABILITATION THERAPY W/ O CC.	0.4214	19.8	16.5
524	TRANSIENT ISCHEMIA	0.5885	22.9	19.0
525	HEART ASSIST SYSTEM, OTHER THAN IMPLANT [8]	2.0841	40.0	33.3
526	PERCUTANEOUS CARVIOVASCULAR PROC W DRUG–ELUTING STENT W AMI [8]	1.3569	32.5	27.0
527	PERCUTANEOUS CARVIOVASCULAR PROC W DRUG–ELUTING STENT W/O AMI [8].	1.3569	32.5	27.0
528	INTRACRANIAL VASCLUAR PROCEDURES WITH PDX HEMORRHAGE [8]	2.0841	40.0	33.3
529	VENTRICULAR SHUNT PROCEDURES WITH CC [2]	0.7372	23.5	19.5
530	VENTRICULAR SHUNT PROCEDURES WITHOUT CC [8]	0.7372	23.5	19.5
531	SPINAL PROCEDURES WITH CC [4]	1.3569	32.5	27.0
532	SPINAL PROCEDURES WITHOUT CC [3]	0.9562	26.1	21.7
533	EXTRACRANIAL VASCULAR PROCEDURES WITH CC [5]	2.0841	40.0	33.3
534	EXTRACRANIAL VASCULAR PROCEDURES WITHOUT CC [8]	1.3569	32.5	27.0
535	CARDIAC DEFIB IMPLANT WITH CARDIAC CATH WITH AMI/HF/SHOCK [8]	2.0841	40.0	33.3
536	CARDIAC DEFIB IMPLANT WITH CARDIAC CATH WITHOUT AMI/HF/SHOCK [5]	2.0841	40.0	33.3
537	LOCAL EXCISION AND REMOVAL OF INTERNAL FIXATION DEVICES EXCEPT HIP AND FEMUR WITH CC [4].	1.3569	32.5	27.0
538	LOCAL EXCISION AND REMOVAL OF INTERNAL FIXATION DEVICES EXCEPT HIP AND FEMUR WITHOUT CC [1].	0.4964	18.5	15.4
539	LYMPHOMA AND LEUKEMIA WITH MAJOR O.R. PROCEDURE WITH CC [8]	2.0841	40.0	33.3
540	LYMPHOMA AND LEUKEMIA WITH MAJOR O.R. PROCEDURE WITHOUT CC [1]	0.4964	18.5	15.4

TABLE 3.—PROPOSED FEDERAL FY 2004 LTC–DRG RELATIVE WEIGHTS, GEOMETRIC MEAN LENGTH OF STAY, AND SHORT-STAYS OF FIVE-SIXTHS AVERAGE LENGTH OF STAY FOR DISCHARGES OCCURRING FROM OCTOBER 1, 2003 THROUGH SEPTEMBER 30, 2004—Continued

LTC–DRG	Description	Relative weight	Geometric average length of stay	5/6th of the average length of stay
541	IMPLANT, PULSATILE HEART ASSIST SYSTEM [6]	0.0000	0.0	0.0

[1] Proposed Relative weights for these LTC–DRGs were determined by assigning these cases to low volume quintile 1.
[2] Proposed Relative weights for these LTC–DRGs were determined by assigning these cases to low volume quintile 2.
[3] Proposed Relative weights for these LTC–DRGs were determined by assigning these cases to low volume quintile 3.
[4] Proposed Relative weights for these LTC–DRGs were determined by assigning these cases to low volume quintile 4.
[5] Proposed Relative weights for these LTC–DRGs were determined by assigning these cases to low volume quintile 5.
[6] Proposed Relative weights for these LTC–DRGs were assigned a value of 0.000.
[7] Proposed Relative weights for these LTC–DRGs were determined after adjusting to account for nonmonotonicity.
[8] Proposed Relative weights for these LTC–DRGs were determined by assigning these cases to the appropriate low volume quintile because they had no LTCH cases in the FY 2002 MedPAR.

[FR Doc. 04–1886 Filed 1–23–04; 5:03 pm]
BILLING CODE 4120–01–P

Federal Register

Friday,
January 30, 2004

Part VI

Department of Veterans Affairs

38 CFR Part 5
Service Requirements for Veterans; Proposed Rule

DEPARTMENT OF VETERANS AFFAIRS

38 CFR Part 5

RIN 2900–AL67

Service Requirements for Veterans

AGENCY: Department of Veterans Affairs.

ACTION: Proposed rule.

SUMMARY: The Department of Veterans Affairs (VA) proposes to amend its Compensation and Pension regulations relating to service requirements for veterans, currently found in part 3 of title 38, Code of Federal Regulations (CFR), and to relocate them in new part 5. We propose to reorganize these regulations in a more logical order, add new section and paragraph headings, rewrite certain sections, and divide certain sections into one or more separate new sections. VA's principal goals in rewriting and reorganizing the current regulations are to provide readers with clearer language and more easily understood regulatory requirements.

DATES: Comments must be received by VA on or before March 30, 2004.

ADDRESSES: Written comments may be submitted by: mail or hand-delivery to Director, Regulations Management (00REG1), Department of Veterans Affairs, 810 Vermont Avenue, NW., Room 1068, Washington, DC 20420; fax to (202) 273–9026; e-mail to *VAregulations@mail.va.gov*; or, through *www.Regulations.gov*. Comments should indicate that they are submitted in response to "RIN 2900–AL67." All comments received will be available for public inspection in the Office of Regulation Policy and Management, Room 1063B, between the hours of 8 a.m. and 4:30 p.m., Monday through Friday (except holidays). Please call (202) 273–9515 for an appointment.

FOR FURTHER INFORMATION CONTACT: Bill Russo, Chief, C&P Regulations Rewrite Project (00REG2), Department of Veterans Affairs, 810 Vermont Avenue, NW., Washington, DC 20420, (202) 273–9515.

SUPPLEMENTARY INFORMATION: The Secretary of Veterans Affairs has established an Office of Regulation Policy and Management (ORPM) to provide centralized management and coordination of VA's rulemaking process. One of the major functions of this office is to oversee a Regulation Rewrite Project (the Project) to improve the clarity and consistency of existing VA regulations. The Project responds to a recommendation made in the October 2001 Report to the Secretary of Veterans Affairs by the VA Claims Processing Task Force. The Task Force recommended that the Compensation and Pension regulations be rewritten and reorganized in order to improve VA's claims adjudication process. Therefore, the Project began its efforts by reviewing, reorganizing and redrafting the regulations in 38 CFR part 3 governing the Compensation and Pension (C&P) program of the Veterans Benefits Administration (VBA). These regulations are among the most difficult VA regulations for readers to understand and apply. Once rewritten, the proposed regulations will be published in several portions for public review and comment. This is the first such portion.

Overview of New Organization

We plan to remove the compensation and pension benefit regulations from 38 CFR part 3 and relocate them in new part 5. We also plan to reorganize the regulations so that all provisions governing a specific benefit are located in the same part, with general provisions pertaining to all compensation and pension benefits also grouped together. We believe this reorganization will allow claimants and their representatives, as well as VA adjudicators, to find information relating to a specific benefit more quickly.

The first major subdivision is "Subpart A—General Provisions." It would include information regarding the scope of the regulations in new part 5, delegations of authority, general definitions, and general policy provisions for this part.

"Subpart B—Service Requirements for Veterans" would include information regarding a veteran's military service, including the minimum service requirement, types of service, periods of war, and service evidence requirements. This subpart is the subject of this document.

"Subpart C—Adjudicative Process, General" would inform readers about types of claims and filing procedures, VA's duties, rights and responsibilities of claimants, and general effective dates, as well as revision of decisions and protection of VA ratings.

"Subpart D—Dependents of Veterans" would provide information about how VA determines whether an individual is a dependent and evidence requirements for such determinations.

"Subpart E—Claims for Service Connection and Disability Compensation" would define service-connected compensation, including direct and secondary service connection. This subpart would inform readers how VA determines entitlement to service connection. The subpart would also contain those provisions governing presumptions related to service connection, rating principles, and effective dates, as well as several special ratings.

"Subpart F—Nonservice-Connected Disability Pensions and Death Pensions" would include information regarding the three types of nonservice-connected pension: Improved pension, old law pension, and section 306 pension. This subpart would also include those provisions that state how to establish entitlement to each pension, and the effective dates governing each pension.

"Subpart G—Dependency and Indemnity Compensation, Death Compensation, and Accrued Benefits" would contain those regulations governing claims for dependency and indemnity compensation (DIC), death compensation, accrued benefits, and benefits awarded, but unpaid, at death. This subpart would also include rules and definitions relating to these benefits and related effective dates and rates of payment.

"Subpart H—Special Benefits for Veterans, Dependents, and Survivors" would pertain to ancillary and special benefits available, including benefits for children with various birth defects.

"Subpart I—Benefits For Filipino Veterans and Survivors" would pertain to the various benefits available to Filipino veterans.

"Subpart J—Burial Benefits" would pertain to burial allowances.

"Subpart K—Matters Affecting Receipt of Benefits" would contain those provisions regarding determinations of willful misconduct, competency, and insanity, which may affect claimants' entitlement to benefits. This subpart would also contain information about forfeiture and renouncement of benefits.

"Subpart L—Payments and Adjustments to Payments" would include general rate-setting rules, several adjustment and resumption regulations, and election of benefit.

The final subpart, "Subpart M—Apportionments and Payments to Fiduciaries or Incarcerated Beneficiaries" would include regulations governing apportionments, benefits for incarcerated beneficiaries, and guardianship.

Some of the regulations in this Notice of Proposed Rulemaking (NPRM) cross-reference other compensation and pension regulations. If those regulations have been published in this or earlier NPRMs, we cite the proposed part 5 section. We also cite the **Federal**

Register page where a proposed part 5 section published in an earlier NPRM may be found. However, where a regulation proposed in this NPRM would cross-reference a proposed part 5 regulation that has not yet been published, we cite to the current part 3 regulation that deals with the same subject matter. If there is no part 3 counterpart to a proposed part 5 regulation that has not yet been published, we have inserted "[regulation that will be published in a future Notice of Proposed Rulemaking]" in the place where the part 5 regulation citation would be placed.

The current part 3 section we cite may differ from its eventual part 5 replacement in some respects, but we believe this method will assist readers in understanding these proposed regulations where no part 5 replacement has yet been published. VA will provide a separate opportunity for public comment on each segment of proposed part 5 regulations before adopting a final version of part 5.

Organization of Proposed Subpart B

This proposed rulemaking pertains to those regulations governing service requirements for compensation and pension benefits. These regulations would be contained in proposed subpart B of new 38 CFR part 5. While these regulations have been substantially restructured and rewritten for greater clarity and ease of use, most of the basic concepts contained in these proposed regulations are the same as in their existing counterparts in 38 CFR part 3. However, a few substantive changes are proposed.

The following table shows the correspondence between the current regulations in part 3 and those proposed regulations contained in this proposed rulemaking:

Proposed part 5 section or paragraph	Based in whole or in part on 38 CFR part 3 section or paragraph
5.20	3.2.
5.21(a)	3.6(a), 3.7(a).
5.21(b)	3.15.
5.22(a)	3.6(b)(1).
5.22(b)	3.6(b)(7).
5.22(c)	new (cross reference).
5.23(a)(1)	3.6(b)(1).
5.23(a)(2)	3.6(c)(1).
5.23(a)(3)	3.6(d)(1) & (2).
5.23(b)(1)	3.6(b)(1).
5.23(b)(2)	3.6(c)(3).
5.23(b)(3)	3.6(d)(4).
5.23(c)	new (cross reference).
5.24(a)	3.6(b)(4) & (7).
5.24(b)(1)	3.6(b)(5).
5.24(b)(2)	3.6(c)(5).
5.24(c)(1)	3.6(c)(4).
5.24(c)(2)	3.6(d)(3).
5.24(c)(3)	3.700(a)(1)(ii).
5.24(d)	new (cross reference).
5.25(a)(1)	3.6(b)(2).
5.25(a)(2)	3.6(c)(2).
5.25(a)(3)	3.6(d)(1) & (2).
5.25(b)	3.6(b)(3).
5.25(c)	3.6(c)(6) & (d)(4)(iii).
5.25(d)	new (cross reference).
5.26	3.7(o).
5.27(a) and (b)	3.7(x).
5.27(c)	3.7(x), 3.400(z).
5.28	3.7(c)–(e), (h)–(l), (n), (p), & (s)–(w).
5.29(a)(1)	3.6(b)(6).
5.29(a)(2)	3.6(b)(7).
5.29(a)(3)	new (cross reference).
5.29(b)	3.6(e).
5.30(a)	3.12(a) first sentence.
5.30(b)	new.
5.30(c)	3.12(a) & (k)(1); 3.14(d).
5.30(d)	new.
5.30(e)	3.12(k)(2)–(3).
5.30(f)	3.12(d).
5.31(a)	new (purpose provision).
5.31(b)	new.
5.31(c)	3.7(b), 3.12(c).
5.31(d)	new.
5.31(e)	3.12(j).
5.32	3.12(c)(6).
5.33	3.12(b), (c)(6).
5.34(a)	new (purpose provision).
5.34(b)	new.
5.34(c)	3.12(e).
5.34(d)	3.400(g).
5.35(a)	new (purpose provision).
5.35(b)	3.12(f).
5.35(c) & (d)	3.12(g).
5.35(e)	3.400(g).
5.36(a)	3.12(h).
5.36(b) and (c)	3.12(i).
5.37(a)	new (purpose provision).
5.37(b)	3.13(a).
5.37(c)	3.13(b).
5.37(d)	3.13(c).
5.38(a)	new (purpose provision).
5.38(b)	3.14(a) & (c).
5.38(c)	3.14(b).
5.39(a)	3.12a(b).
5.39(b)(1)	3.12a(c)(1).
5.39(b)(2)	3.12a(c)(2).
5.39(c)(1)	3.12a(a)(1).
5.39(c)(2)	3.203(c) last sentence.
5.39(d)	3.12a(d).
5.39(e)	3.15.
5.39(f)	3.12a(e).
5.40(a)	3.203(a).
5.40(b)	3.203(a)(2).
5.40(c)	3.203(a)(1) & (3).
5.40(d)	3.203(c).

Readers who use this table to compare existing regulatory provisions with the proposed provisions, and who observe a substantive difference between them, should consult the text that appears later in this document for an explanation of significant changes in each regulation. Not every paragraph of every current part 3 section affected by these proposed regulations is accounted for in the table. In some instances other portions of the part 3 sections that are contained in these proposed regulations appear in subparts of part 5 that will be published for public comment at a later time. For example, a reader might find a reference to paragraph (a) of a part 3 section in the table, but no reference to paragraph (b) of that section because paragraph (b) will be addressed in a future notice of proposed rulemaking. The table also does not include material from the current sections that will be removed from part 3 and not carried forward to part 5. A listing of material VA proposes to remove from part 3 appears later in this document.

Periods of War and Types of Military Service

In new § 5.20, we propose revisions to the rules concerning what periods of service VA recognizes as wartime service, beginning with the Mexican border period. Most of the information is presented in a table for easy reference.

Because there are no veterans of the Civil War, the Indian Wars, or the Spanish-American War on VA's compensation and pension rolls and most, if not all, dependents with claims based on these earlier periods of war have already filed them, we propose to delete the provisions related to these periods of war and refer regulation users to the applicable statutory provisions concerning these earlier periods of war. This deletion would not affect benefit entitlement in any way. Should the occasion arise, VA will adjudicate any new claim using statutory definitions of earlier periods of war.

A definition of the term "period of war" in 38 U.S.C. 1101(2)(A) extends the period recognized as World War I service for the purpose of benefits awarded under 38 U.S.C. chapter 11 (for example, disability compensation, death compensation, and benefits under 38 U.S.C. 1151, "Benefits for persons disabled by treatment or vocational rehabilitation"). World War I is similarly extended by 38 U.S.C. 1501(2) for the purpose of non-service-connected pension benefits awarded under 38 U.S.C. chapter 15. We propose to clarify the nature of these extensions in § 5.20(b)(2).

Similarly, the definition of the term "period of war" in 38 U.S.C. 1101(2)(B) extends the period recognized as World War II service for benefits awarded under 38 U.S.C. chapter 11. These proposed amendments would clarify the limited nature of this extension in § 5.20(c).

Next; VA proposes to remove current 38 CFR 3.6, "Duty periods;" § 3.7, "Individuals and groups considered to have performed active military, naval, or air service;" and § 3.15, "Computation of service;" and to rewrite them as nine separate, new sections that focus on the individual performing the duty instead of the type of duty performed. The new sections will be numbered §§ 5.21 to 5.29.

We propose in the first section, § 5.21, to state the general conditions for active military service. Essentially, we propose to use the term "active military service" in lieu of the longer term "active military, naval, or air service" in 38 U.S.C. 101(24) and current part 3 for simplicity and convenience. Note that, as an equivalent to the longer "active military, naval, or air service," "active military service" is a broader term than "active duty." Compare 38 U.S.C. 101(21) with 38 U.S.C. 101(24).

Proposed § 5.21(a)(6) includes the provisions from current § 3.7(a) concerning the duty status of active duty and reserve persons assigned to the Postmaster General for the aerial transportation of mail from February 10, 1934, through March 26, 1935. This provision concerns the continuation of active duty for the persons involved and not persons "considered to have performed" active duty, as stated in § 3.7, and is more appropriately included with the active military service provisions.

In addition, we propose moving the types of duty not counted as active military service, such as time on agricultural furlough or time lost when absent without leave, from current § 3.15, "Computation of service," to § 5.21(b). One of these provisions is "time lost [while] under arrest (without acquittal)." We propose to expand the exception for acquittal to include situations where the charges which led to arrest are dismissed. If charges are dismissed, there would never be a conviction for the offenses charged to taint the period of service in question. Further, we propose to clarify that the rule that time spent serving a court-martial sentence is not active military service for VA purposes is subject to 10 U.S.C. 875(a) that provides, under certain circumstances, for the restoration of "all rights, privileges, and property affected by an executed part of a court-martial sentence which has been set aside or disapproved."

Finally, we propose to remove the sentence in § 3.15 concerning leave authorized by General Order No. 130, War Department, for claims based on Spanish-American War service as being included in active military service. We propose to remove this sentence because according to VA records, the last veteran of this war died in 1992. Although VA is paying death benefits to survivors based on this service, we do not believe we will receive any new claims from veterans who served in the Spanish-American War. In addition, we believe that the provision is unnecessary because periods of authorized leave are normally included as active military service.

We propose to define the periods of duty that count as active duty in § 5.22, stating that active duty is full-time duty and continues until midnight of the date of discharge from active duty.

"Special work" is a category of service performed by Reservists, normally for limited periods of time. For example, 10 U.S.C. 115, "Personnel strengths: Requirements for annual authorization," refers at subsection (d)(6) to "Members of reserve components on active duty for 180 days or less to perform special work" and at subsection (d)(9) to "members of reserve components * * * on active duty for more than 180 days but less than 271 days to perform special work in support of the combatant commands." We have not addressed whether active duty for special work is active duty for VA purposes in the text of these proposed regulations. However, we believe that it may be the case for at least some special work assignments, particularly those that involve combat duties. We invite public comment on whether, and to what extent, VA should recognize military duty for special work as active duty for VA purposes.

We propose in § 5.23 to state how VA classifies various types of service performed by Reserve and National Guard personnel. One change to the current section, § 3.6, will be removal of the provisions for determining active duty for training for full-time duty performed by the National Guard of any State while participating in the reenactment of the Battle of First Manassas in July 1961. We believe all National Guard members eligible for benefits under this provision have already applied for benefits and there will be no new applicants. If we receive a new application for entitlement to benefits under this provision, we will consider the application under the authorizing public law (Public Law 87–83, 75 Stat. 200 (1961)). Otherwise, we have simply restructured the current section and no substantive changes are proposed.

In § 5.24, we propose to include all the provisions applicable to types of duty for Armed Services Academy cadets, midshipmen, preparatory school attendees, and Senior Reserve Officers' Training Corps members. This proposed section includes a provision from current § 3.700(a)(1)(ii), which states "Time spent by members of the ROTC in drills as part of their activities as members of the corps is not active service." We have moved this sentence to this new section because it relates directly to the topic of this new section.

Likewise, proposed § 5.25 contains all the provisions pertaining to duty and related service in the Public Health Service, in the Coast and Geodetic Survey and its successor agencies, and of temporary members of the Coast Guard Reserves. Under current § 3.6(b)(3)(ii), one of the ways in which the service of a commissioned officer of the Coast and Geodetic Survey or of its successor agencies is considered to be active duty is if the officer was "(i)n the Philippine Islands on December 7, 1941, and continuously in such islands thereafter." Under the current regulation and in it's authorizing statute, 38 U.S.C. 101(21)(C), this means continuously thereafter until July 29, 1945. We propose to make that clearer in § 5.25(b)(1)(iv).

We propose to extract from § 3.7(o) and place in reorganized § 5.26, "Circumstances where persons ordered to service, but who did not serve, are considered to have performed active duty," provisions concerning entitlement to VA benefits for certain National Guard personnel and for persons who volunteer or are drafted for military service and incur injury or disease while engaged in required activities before entry into active Federal military duty. This proposed section explains that persons injured during an induction examination, or while traveling to an induction processing center, or National Guard members reporting to a rendezvous, or under other similar circumstances, are considered to have performed active duty for purposes of entitlement to VA benefits.

The remainder of current § 3.7 concerns individuals or groups who are not military personnel in the usual sense, but who have contributed significantly to the national defense. Because of the contributions of these individuals and groups, Congress (through specific statutory enactments), VA (through statutory interpretations in Administrator's Decisions), courts, and the Secretary of Defense (exercising authority granted in section 401 of Public Law 95–202) have determined that their work warrants recognition as active military service.

VA proposes to include information about these individuals and groups in two separate proposed sections, § 5.27, "Individuals and groups designated by the Secretary of Defense as having performed active military service," and

§ 5.28, "Other individuals and groups designated as having performed active military service." Both sections list these individuals and groups in alphabetical order.

In § 5.27, we propose to update the list, currently contained in 38 CFR 3.7(x), of those individuals and groups the Secretary of Defense (frequently through the Secretary of the Air Force acting as Executive Agent of the Secretary of Defense) has determined have performed active military service. Notice of these determinations is given to the public in **Federal Register** notices issued by the Department of Defense. These notices include the date the Secretary of Defense, or the Secretary's agent, recognized the applicable group(s) as having performed active military service for the purpose of VA benefits. We propose to include recognition effective date information for each group listed in § 5.27.

The following table includes a list of the relevant groups (in alphabetical order) and the recognition effective date for each group, as well as a citation to the applicable **Federal Register** notice describing the decision by the Secretary of Defense. There are two exceptions with respect to **Federal Register** citations. One group, the Women's Air Forces Service Pilots (WASP), was specifically recognized by Pub. L. 95–202, the statute that authorizes the Secretary of Defense to make these determinations. In that case, the effective date of recognition is the effective date specified in the statute. Information about another group, "Quartermaster Corps Keswick Crew on Corregidor (WWII)," does not appear to have been published in the **Federal Register**. In that case, we have cited the Department of Defense memorandum recognizing the group.

Individuals and groups designated by the Secretary of Defense as having performed active military service	Individual or group recognition date	FEDERAL REGISTER citation or authority recognizing the individual or group
American Merchant Marine in oceangoing service, during the Period of Armed Conflict, December 7, 1941, to August 15, 1945.	Recognized effective January 19, 1988.	53 FR 2775.
The approximately 50 Chamorro and Carolinian former native policemen who received military training in the Donnal area of central Saipan and were placed under the command of Lt. Casino of the 6th Provisional Military Police Battalion to accompany United States Marines on active, combat-patrol activity from August 19, 1945, to September 2, 1945.	Recognized effective September 30, 1999.	64 FR 56773.
Civilian Crewmen of the United States Coast and Geodetic Survey (USCGS) vessels, who performed their service in areas of immediate military hazard while conducting cooperative operations with and for the U.S. Armed Forces within a time frame of December 7, 1941, to August 15, 1945. Qualifying USCGS vessels specified by the Secretary of Defense, or his or her designee, are the Derickson, Explorer, Gilbert, Hilgard, E. Lester Jones, Lydonia, Patton, Surveyor, Wainwright, Westdahl, Oceanographer, Hydrographer, and the Pathfinder.	Recognized effective April 8, 1991.	56 FR 23054, 57 FR 24600.
Civilian employees of Pacific Naval Air Bases who actively participated in Defense of Wake Island during World War II.	Recognized effective January 22, 1981.	46 FR 11857.
Civilian Navy Identification Friend or Foe (IFF) Technicians, who served in the Combat Areas of the Pacific during World War II (December 7, 1941, to August 15, 1945).	Recognized effective August 2, 1988.	53 FR 32425.
Civilian personnel assigned to the Secret Intelligence Element of the Office of Strategic Services (OSS).	Recognized effective December 27, 1982.	48 FR 1532.
Engineer Field Clerks (WWI)	Recognized effective August 31, 1979.	44 FR 55622.
Guam Combat Patrol	Recognized effective May 10, 1983.	48 FR 23295.
Honorably discharged members of the American Volunteer Group (Flying Tigers), who served during the Period December 7, 1941, to July 18, 1942.	Recognized effective May 3, 1991.	56 FR 26072.
Honorably discharged members of the American Volunteer Guard, Eritrea Service Command, who served during the Period June 21, 1942, to March 31, 1943.	Recognized effective June 29, 1992.	57 FR 34766.
Male Civilian Ferry Pilots	Recognized effective July 17, 1981.	46 FR 39197.
The Operational Analysis Group of the Office of Scientific Research and Development, Office of Emergency Management, which served overseas with the U.S. Army Air Corps from December 7, 1941, through August 15, 1945.	Recognized effective August 27,1999.	64 FR 53364.
Quartermaster Corps Female Clerical Employees serving with the AEF (American Expeditionary Forces) in World War I.	Recognized effective January 22, 1981.	46 FR 11857.

Individuals and groups designated by the Secretary of Defense as having performed active military service	Individual or group recognition date	FEDERAL REGISTER citation or authority recognizing the individual or group
Quartermaster Corps Keswick Crew on Corregidor (WWII).	Recognized effective February 7, 1984.	Memorandum from the Acting Assistant Secretary of the Air Force (Manpower, Reserve Affairs and Installations), Determination of Active Military Service (Feb. 7, 1984) (on file with DOD Civilian/Military Service Review Board)).
Reconstruction Aides and Dietitians in World War I	Recognized effective July 6, 1981.	46 FR 37306.
Signal Corps Female Telephone Operators Unit of World War I.	Recognized effective May 15, 1979.	44 FR 32019.
Three scouts/guides, Miguel Tenorio, Penedicto Taisacan, and Cristino Dela Cruz, who assisted the U.S. Marines in the offensive operations against the Japanese on the Northern Mariana Islands from June 19, 1944, through September 2, 1945.	Recognized effective September 30, 1999.	64 FR 56773.
U.S. civilian employees of American Airlines, who served overseas as a result of American Airlines' contract with the Air Transport Command during the Period December 14, 1941, through August 14, 1945.	Recognized effective October 5, 1990.	55 FR 46706.
U.S. civilian female employees of the U.S. Army Nurse Corps while serving in the defense of Bataan and Corregidor during the Period January 2, 1942, to February 3, 1945.	Recognized effective December 13, 1993.	59 FR 298.
U.S. Civilian Flight Crew and Aviation Ground Support Employees of Braniff Airways, who served overseas in the North Atlantic or under the jurisdiction of the North Atlantic Wing, Air Transport Command (ATC), as a result of a contract with the ATC during the Period February 26, 1942, through August 14, 1945.	Recognized effective June 2, 1997.	62 FR 36263.
U.S. Civilian Flight Crew and Aviation Ground Support Employees of Consolidated Vultree Aircraft Corporation (Consairway Division), who served overseas as a result of a contract with the Air Transport Command during the Period December 14, 1941, through August 14, 1945.	Recognized effective June 29, 1992.	57 FR 34765.
U.S. Civilian Flight Crew and Aviation Ground Support Employees of Northeast Airlines Atlantic Division, who served overseas as a result of Northeast Airlines' Contract with the Air Transport Command during the Period December 7, 1941, through August 14, 1945.	Recognized effective June 2, 1997.	62 FR 36263.
U.S. Civilian Flight Crew and Aviation Ground Support Employees of Northwest Airlines, who served overseas as a result of Northwest Airline's contract with the Air Transport Command during the Period December 14, 1941, through August 14, 1945.	Recognized effective December 13, 1993.	59 FR 297.
U.S. Civilian Flight Crew and Aviation Ground Support Employees of Pan American World Airways and Its Subsidiaries and Affiliates, who served overseas as a result of Pan American's Contract with the Air Transport Command and Naval Air Transport Service during the Period December 14, 1941, through August 14, 1945.	Recognized effective July 16, 1992.	57 FR 34765.
U.S. Civilian Flight Crew and Aviation Ground Support Employees of Transcontinental and Western Air (TWA), Inc., who served overseas as a result of TWA's contract with the Air Transport Command during the Period December 14, 1941, through August 14, 1945. The "Flight Crew" includes pursers.	Recognized effective May 13, 1992.	57 FR 24479, 68 FR 11068.
U.S. Civilian Flight Crew and Aviation Ground Support Employees of United Air Lines (UAL), who served overseas as a result of UAL's contract with the Air Transport Command during the Period December 14, 1941, through August 14, 1945.	Recognized effective May 13, 1992.	57 FR 24478.
U.S. civilian volunteers, who actively participated in the Defense of Bataan.	Recognized effective February 7, 1984.	49 FR 7849.
U.S. civilians of the American Field Service (AFS), who served overseas operationally in World War I during the Period August 31, 1917, to January 1, 1918.	Recognized effective August 30, 1990.	55 FR 46707.
U.S. civilians of the American Field Service (AFS), who served overseas under U.S. Armies and U.S. Army Groups in World War II during the Period December 7, 1941, through May 8, 1945.	Recognized effective August 30, 1990.	55 FR 46707.

Individuals and groups designated by the Secretary of Defense as having performed active military service	Individual or group recognition date	FEDERAL REGISTER citation or authority recognizing the individual or group
U.S. Merchant Seamen who served on blockships in support of Operation Mulberry.	Recognized effective October 18, 1985.	50 FR 46332.
Wake Island Defenders from Guam	Recognized effective April 7, 1982.	47 FR 17324.
Women's Air Forces Service Pilots (WASP)	Recognized effective November 23, 1977.	Sec. 401, Pub. L. 95–202, 91 Stat. 1433, 1449.
Women's Army Auxiliary Corps (WAAC)	Recognized effective March 18, 1980.	45 FR 23716, 45 FR 26115.

Proposed § 5.27(a) provides basic information about the designation of individuals and groups by the Secretary of Defense. These individuals and groups are listed in § 5.27(b).

We propose to add three additional groups recognized by the Department of Defense to update the list in proposed § 5.27.

In the **Federal Register** of October 1, 1999 (64 FR 53364–65), the Secretary of the Air Force published a notice that he had determined that the service of the members of the group known as "The Operational Analysis Group of the Office of Scientific Research and Development, Office of Emergency Management, which served overseas with the U.S. Army Air Corps from December 7, 1941, through August 15, 1945," shall be considered active duty for the purpose of all laws administered by VA.

In the **Federal Register** of October 21, 1999 (64 FR 56773–74), the Secretary of the Air Force published a notice that he had determined that the service of the members of the groups known as:

[T]hree scouts/guides, Miguel Tenorio, Penedicto Taisacan, and Cristino Dela Cruz, who assisted the U.S. Marines in the offensive operations against the Japanese on the Northern Mariana Islands from June 19, 1944, through September 2, 1945, and * * * "the approximately 50 Chamorro and Carolinian former, native policemen who received military training in the Donnal area of central Saipan and were placed under the command of Lt. Casino of the 6th Provisional Military Police Battalion to accompany United States Marines on active, combat-patrol activity from August 19, 1945, to September 2, 1945,

shall be considered to be active duty for the purpose of all laws administered by VA.

We also propose to add additional information concerning three groups already recognized. The first group is "[c]ivilian Crewmen of the United States (U.S.) Coast and Geodetic Survey vessels, who performed their service in areas of immediate military hazard while conducting cooperative operations with and for the U.S. Armed Forces within a time frame of December 7, 1941, to August 15, 1945." The Department of Defense has specifically designated qualifying vessels upon which members of the group must have served. 57 FR 24600, June 10, 1992. We propose adding this information at § 5.27(b)(3) to assist claimants and their representatives in identifying service potentially qualifying for VA benefits.

In proposed § 5.27(b)(7), we have amended the title of the group "Engineer Field Clerks" to the more complete "Engineer Field Clerks (WWI)." See 44 FR 55622, September 27, 1979.

The third group is "U.S. Civilian Flight Crew and Aviation Ground Support Employees of Transcontinental and Western Air (TWA), Inc., who served overseas as a result of TWA's contract with the Air Transport Command during the Period December 14, 1941, through August 14, 1945." On February 21, 2003, the Secretary of the Air Force (acting as Executive Agent of the Secretary of Defense) determined that "Flight Crew" includes pursers. 68 FR 11068, March 7, 2003. This information has been added at proposed § 5.28(b)(25).

One of the Project's design goals is to associate effective date rules that concern specific regulations with those regulations so that related material will be in one place for the convenience of claimants and their representatives and VA personnel who adjudicate claims. Therefore, we propose to include rules for determining the effective date for awarding VA benefits to a member of a group that would be listed in proposed § 5.27 as proposed § 5.27(c). Proposed § 5.27(c) would replace effective date rules for awards to these groups currently included in the introduction to § 3.7(x) and in § 3.400(z).

38 U.S.C. 5110(g) provides that:

(g) Subject to the provisions of section 5101 of this title [concerning the requirement for filing a claim for VA benefits], where compensation, dependency and indemnity compensation, or pension is awarded or increased pursuant to any Act or administrative issue, the effective date of such award or increase shall be fixed in accordance with the facts found but shall not be earlier than the effective date of the Act or administrative issue. In no event shall such award or increase be retroactive for more than one year from the date of application therefor or the date of administrative determination of entitlement, whichever is earlier.

Another statutory provision, 38 U.S.C. 1832(b)(2), as amended by the Veterans Benefits Act of 2003, Pub. L. No. 108–183, 117 Stat. 2651 (2003), extends § 5110(g) to cover claims for certain benefits for children of Vietnam veterans and of veterans of covered service in Korea under 38 U.S.C. chapter 18.

Because each decision of the Department of Defense to include a new group is a liberalizing change with respect to eligibility for VA benefits, we propose to treat the decision as a liberalizing "administrative issue" under 5110(g). The effective date of recognition established by the Department of Defense would be the effective date of the "administrative issue."

While neither 38 U.S.C. 5110(g) nor its current implementing regulation, § 3.114, is specifically cited in current § 3.400(z), we note that this approach is consistent with the approach used in § 3.400(z). Note, for example, the potential for up to one year in retroactive benefits under certain circumstances in § 3.400(z)(2)(iii) and in 38 U.S.C. 5110(g). This approach would also produce a result that appears to be consistent with the view of the Department of Defense. For example, the **Federal Register** notice of the group described at proposed § 5.27(b)(2) states that benefits are not retroactive. *See* 64 FR 56773.

In drafting the 38 U.S.C. 5110(g)-based effective date provision in proposed § 5.27(c), we have substituted "date entitlement arose" for "facts found." VA interprets "facts found" and another phrase used in effective date rules, "date entitlement arose," as having the same basic meaning. We are proposing to use only one of these terms, "date entitlement arose," in all of our proposed regulations to improve consistency. "Date entitlement arose" will be defined in a later notice of proposed rulemaking as part of the project.

The effective date rules in proposed § 5.27(c) are consistent with relevant portions of another 38 U.S.C. 5110(g)-based regulation, current § 3.114.

With respect to the individuals and groups described in proposed § 5.27, current § 3.7(x) provides that "[t]he effective dates for an award based upon such service shall be as provided by § 3.400(z) and 38 U.S.C. 5110, except that in no event shall such an award be made effective earlier than November 23, 1977." We have not included similar information in proposed § 5.27(c). The November 23, 1977, date is the effective date of Pub. L. 95–202, which recognized the service of the Women's Air Forces Service Pilots (WASP) and authorized the Secretary of Defense to recognize the service of similarly situated groups in the future. Thus the only group recognized effective November 23, 1977, is the WASP group, as noted in proposed § 5.27(b)(32). The recognition effective date of all other groups is later, as shown in proposed § 5.27(b).

In § 5.28, we propose to list those individuals and groups determined specifically by the Congress, or by court or VA decisions interpreting applicable legislative provisions, to have performed active military service. These groups are currently listed in various paragraphs of current § 3.7, as shown on the table presented earlier.

We propose to update the list of groups and descriptions of the groups where indicated. Proposed § 5.28(a) would add service in the Alaska Territorial Guard during World War II to the list of groups and individuals. *See* Public Law 106–259, 114 Stat. 656 (2000). We have also added material to § 5.28(e) to notify readers that the Coast Guard is now under the jurisdiction of the Department of Homeland Security. *See* Public Law 107–296, 116 Stat. 2135 (2002). In addition, we propose to correct an error in current § 3.7(h), which lists "[a]ctive service in Coast Guard on or after January 29, 1915." The relevant date is actually January 28, 1915. *See* Pub. L. No. 77–182, 55 Stat. 598 (1941). *See also* 14 U.S.C. 1 ("The Coast Guard as established January 28, 1915, shall be a military service and a branch of the Armed Forces of the United States at all times.")

Proposed § 5.29, "Circumstances under which certain travel periods may be classified as military service," contains the rules pertaining to when a service member performing authorized travel is considered to be on active duty, active duty for training, or inactive duty training. Consistent with the language of current § 3.6(e)(2), § 5.29(b)(3) restates that the burden of proof is on the claimant to show that disability or death was incurred while the service member was going to, or returning from, authorized active duty for training or inactive duty training. *See* 38 U.S.C. 106(d)(3). We propose to add a cross reference to provisions in § 5.26 concerning travel by persons who were ordered to service but did not serve.

Service Creditable for VA Benefits

Current § 3.12, the rules pertaining to service requirements for VA benefits, is long and extremely complex. It contains rules pertaining to several subjects: How VA determines whether discharges were issued under other than dishonorable conditions; certain statutory bars to VA benefits; the effect of discharge upgrades by different armed forces boards on decisions VA makes concerning service members' discharges; the effect of certain special discharge-upgrade programs in the 1970s; and various other subjects. We propose to divide § 3.12 by topic into separate sections, which would be numbered §§ 5.30 through 5.36.

A requirement for VA benefits is status as a "veteran," which means that the service member was discharged or released from active military service under other than dishonorable conditions. *See* 38 U.S.C. 101(2). Proposed § 5.30 would state the rules pertaining to VA's determinations of whether a service member's discharge or release was under other than dishonorable conditions.

Proposed revisions include updating terminology to reflect the change by the Department of Defense in the term "undesirable discharge" to "other than honorable discharge."

VA proposes to clarify, through new §§ 5.30(b)(1) and 5.31(b)(1), that a service member's discharge or release from service under other than honorable conditions, if it bars benefits at all, or a discharge or dismissal for commission of an act that results in a statutory bar to VA benefits, bars VA benefits only based on the period of service for which the relevant discharge, release, or dismissal was issued. Neither bars the award of benefits based upon other qualifying periods of service. This would avoid potential confusion in cases where the veteran has one period of service that ended with a discharge under dishonorable conditions and one or more other periods of service which ended with a discharge under other than dishonorable conditions.

This matter was considered by VA's General Counsel in 1991 in response to a request from the Department of the Air Force for an opinion as to the effect of a discharge under dishonorable conditions on a service member's eligibility to receive veterans' benefits based on another period of service which terminated under honorable conditions. The General Counsel held that:

> Unless the Secretary of Veterans Affairs determines that an individual is guilty of an offense listed in 38 U.S.C. 6104 (formerly § 3504) (mutiny, treason, sabotage, or rendering assistance to an enemy of the United States or of its allies) or the individual is convicted of an offense listed in 38 U.S.C. 6105 (formerly § 3505) (articles 94 (mutiny or sedition), 104 (aiding the enemy), and 106 (spying) of the Uniform Code of Military Justice; various provisions of title 18, United States Code, relating to espionage, treason, rebellion, sedition, subversive activities, and sabotage; violations of the Atomic Energy Act of 1954 and the Internal Security Act of 1950), a discharge under dishonorable conditions does not bar that individual from receiving gratuitous benefits administered by the Department of Veterans Affairs, including burial in a national cemetery, based on a prior period of service which terminated under conditions other than dishonorable. However, if VA determines, subject to the severe limitations on application of 38 U.S.C. 6104 to U.S. residents and domiciliaries after September 1, 1959, under 38 U.S.C. 6103(d)(1) (formerly § 3503(d)(1)), that an individual is guilty of an offense listed in 38 U.S.C. 6104, or if an individual is convicted of an offense listed in 38 U.S.C. 6105, such individual is barred from receiving all accrued or future benefits regardless of whether the individual may have had a prior period of honorable service.

VAOPGCPREC 61–91.

Proposed §§ 5.30(b) and 5.31(b) reflect the general rule that a discharge or release under dishonorable conditions applies only to the period of service to which the discharge or release pertains, but that this general rule does not preclude forfeiture of VA benefits under 38 U.S.C. 6103 through 6105 or similar statutes governing forfeiture of VA benefits.

We also note that, while it would be highly unusual, the period of service terminating under other than dishonorable conditions could follow as well as precede the period of service terminating under dishonorable conditions. For example, none of the controlling authorities discussed in VAOPGCPREC 61–91 requires a sequence. The issue is whether the period of service on which the claim is based was terminated by discharge or release under conditions other than dishonorable.

Proposed § 5.30(c) describes the discharges VA will recognize as being under other than dishonorable conditions. Proposed § 5.30(d) lists those discharges VA will recognize as being under dishonorable conditions. Section 5.30(e) lists the discharges for which VA will make a character of discharge determination. These provisions are based on the explicit provisions of current § 3.12, as noted in the derivation table included earlier in this document, or are implicit in the current regulatory scheme.

Except where the law otherwise specifically provides (such as in the case of certain discharge upgrade programs treated in proposed § 5.36), VA has long considered itself bound by discharges under honorable conditions issued by a service department, such as honorable discharges and general discharges under honorable conditions. Discharges under honorable conditions are, of course, also discharges that are under other than dishonorable conditions. In addition, VA treats uncharacterized entry level separations as being under other than dishonorable conditions. *See* current § 3.12(a) and (k)(1), § 3.14(d). These are the discharges described in proposed § 5.30(c).

A dishonorable discharge is, by definition, a discharge under dishonorable conditions and issuance of such discharges is a matter for the Department of Defense. This is the subject of proposed § 5.30(d).

Section 5.30(e) describes the types of discharges that lie in a middle ground, neither clearly honorable nor dishonorable: An other than honorable discharge (formerly classified as an "undesirable" discharge); a bad conduct discharge; and certain uncharacterized administrative separations. It is in those cases that VA will make the character of discharge determination because VA must decide whether they are, or are not, discharges "under conditions other than dishonorable" in order to determine eligibility for VA benefits. *See generally Camarena* v. *Brown*, 6 Vet. App. 565 (1994).

While it does not represent a substantive change, we also propose, in § 5.30(e)(3), to add a parenthetical explaining what "dropped from the rolls" means. VA understands this expression to mean the administrative termination of military status and pay. The U.S. Supreme Court has noted in *Clinton* v. *Goldsmith*, 526 U.S. 529 (1999) that:

> When a service member is dropped from the rolls, he forfeits his military pay. *See* 37 U.S.C. 803. The drop-from-the-rolls remedy targets a narrow category of service members who are absent without leave (AWOL) or else have been convicted of serious crimes. Since 1870, the President has had authority to drop from the rolls of the Army any officer who has been AWOL for at least three months. *See* Act of July 15, 1870, § 17, 16 Stat. 319. The power was subsequently extended to officers confined in prison after final conviction by a civil court, *see* Act of Jan. 19, 1911, ch. 22, 36 Stat. 894, and then to "any armed force" officer AWOL for at least three months or else finally sentenced to confinement in a Federal or State penitentiary or correctional institution, *see* Act of May 5, 1950, § 10, 64 Stat. 146.

Id. at 532 n.1.

Proposed § 5.30(f) lists the offenses or events leading to a discharge that VA will recognize as a discharge or separation under dishonorable conditions. Current § 3.12(d)(3) lists "An offense involving moral turpitude. This includes, generally, conviction of a felony." We propose to retain this rule, including the example of conviction of a felony, but to add a general definition of moral turpitude. VA believes that such a definition would be helpful to claimants and to VA employees who adjudicate VA benefit claims.

Claimants ought to be able to know with at least some degree of certainty whether or not a provision applies to their case. This is particularly true of provisions that may serve to bar VA benefits.

The phrase "moral turpitude" is one commonly used in the law and has been examined by legal writers in some depth.

There seems to be a common thread running through the majority of cases concerning misdeeds considered to involve moral turpitude. A crime involving moral turpitude is a criminal act that is done with the willful intent to harm another person or entity through harm to their person or property. In an analysis of more than 100 years of case law involving courts' struggles to define "moral turpitude," one author notes the following with respect to the major categories of crimes found to involve moral turpitude:

> Crimes against the person involve moral turpitude when the local statute defining the crime requires "malicious intent." * * * Crimes against property involve moral turpitude if the criminal statute requires an intent to deprive, defraud, or destroy. * * * Aggravated sexual crimes always involve moral turpitude, but some sexual offenses do not. Examples of aggravated sexual crimes are: rape, sexual misconduct with a minor, prostitution, sodomy, lewdness, and gross indecency. Sexual offenses that do not involve moral turpitude include vagrancy, maintaining a nuisance, and fornication. * * * Crimes involving family relationships that courts have held to be "crimes involving moral turpitude" include: adultery, abortion, bigamy, spousal abuse, and child abuse. * * * Crimes of fraud against the government or its authority, like all crimes with an element of fraud, are "crimes involving moral turpitude."

Brian C. Harms, *Redefining "Crimes of Moral Turpitude": A Proposal to Congress*, 15 Geo. Immigr. L.J. 259, 267–69 (Winter 2001).

An exhaustive analysis of the concept of moral turpitude in *American Law Reports Federal* includes the observation that:

> The presence or absence of criminal or 'evil' intent as an essential element of the crime under consideration is frequently considered as a factor indicative of the moral turpitude of the offense; the 'evil' intent may be evidenced by the use of unjustified violence or the endangerment of human life * * *, or by the presence of an intent to defraud as a necessary ingredient of the offense. * * *

Annotation, *What Constitutes "Crime Involving Moral Turpitude" Within Meaning of §§ 212(a)(9) and 241(a)(4) of Immigration and Nationality Act (8 USCA §§ 1182(a)(9), 1251(a)(4)), and Similar Predecessor Statutes Providing for Exclusion or Deportation of Aliens Convicted of Such Crime*, 23 A.L.R. Fed. 480, 488 (1975).

VA's proposed definition is: "an offense involves 'moral turpitude' if it is unlawful, it is willful, it is committed without justification or legal excuse, and it is an offense which a reasonable person would expect to cause harm or loss to person or property."

The basic concept is that VA will look at the facts and circumstances surrounding the commission of acts leading to discharge to determine whether they do, or do not, involve moral turpitude under the proposed definition.

When a discharge or release from service is because of one of various offenses listed in current § 3.12(d), VA will consider that discharge or release to be under dishonorable conditions. This list includes the following at § 3.12(d)(5):

> Homosexual acts involving aggravating circumstances or other factors affecting the performance of duty. Examples of homosexual acts involving aggravating circumstances or other factors affecting the performance of duty include child molestation, homosexual prostitution, homosexual acts or conduct accompanied by assault or coercion, and homosexual acts or conduct taking place between service members of disparate rank, grade, or status when a service member has taken advantage of his or her superior rank, grade, or status.

Since the time when these words were written in the 1970s, integration of men and women into almost all military specialties and every aspect of military life has become common. We believe it is appropriate for VA to clearly state that all of the sexual offenses listed in this paragraph are egregious no matter who commits them. Therefore, in § 5.30(f)(5), we propose to replace the word "homosexual" with "sexual," in order to make this rule applicable to all persons.

Proposed § 5.31 describes statutory bars to VA benefits and the exceptions to those bars. Proposed § 5.31(c)(1) would provide information concerning 10 U.S.C. 874(b), which grants service department secretaries the authority to "substitute an administrative form of discharge for a discharge or dismissal executed in accordance with the sentence of a court-martial." VA's General Counsel has held that such a discharge upgrade does not remove the statutory bar to VA benefits that results from discharge or dismissal by reason of the sentence of a general court-martial. In VAOPGCPREC 10–96, after reviewing legislative history and other relevant matters, including the interpretation of 10 U.S.C. 874(b) by the Department of the Navy, the VA General Counsel reasoned at paragraph 11 that:

> In view of the foregoing, we conclude that an upgraded discharge awarded pursuant to 10 U.S.C. 874(b) does not alter an individual's service records to change the fact that the individual was discharged or dismissed by reason of the sentence of a general court-martial. In the instant case, the revised DD 214 issued to the appellant, while reflecting a discharge under honorable conditions, continues to identify the sentence of the court-martial as the reason for his discharge. Congress has made clear that a statutory bar to benefits under 38 U.S.C. 5303(a) will be removed "[o]nly in instances when the Board for Correction of Military Records changes the reasons for discharge." H.R. Rep. No. 580, 95th Cong., 1st Sess. at 11, reprinted at 1977 U.S.C.C.A.N. at 2854. Accordingly, because an upgraded discharge issued under 10 U.S.C. 874(b) changes the character of discharge, but not the reasons for discharge, an upgraded discharge issued pursuant to 10 U.S.C. 874(b) does not remove the statutory bar to benefits under section 5303(a) as to individuals discharged or dismissed by reason of the sentence of a general court-martial.

Proposed § 5.31(c)(2) provides the rules concerning discharge or dismissal "[a]s a conscientious objector who refused to perform military duty, wear the uniform, or comply with lawful orders of competent military authorities" as a bar to VA benefits.

Another statutory bar to VA benefits is found in title 38 of the United States Code, subsections 5303(a) and (c). These subsections bar the payment of VA benefits to an alien who is discharged because of his or her status as an alien during a time of hostilities between the United States and another nation where the discharge is initiated by the alien's own application or solicitation. Proposed § 5.31(c)(6) concerns this bar to benefits based on alienage. This proposed revision eliminates material in current § 3.7(b) concerning discharges for alienage upgraded to honorable prior to January 7, 1957, by certain military boards. The material provides that VA accepts such upgrades as proof that a discharge was not at the alien's request. It was added at a time when the burden of proof was on the service member to prove that a discharge for alienage was not based on the service member's application or solicitation. This material is no longer necessary because the burden of proving that the discharge was at the service member's request is now on the government under 38 U.S.C. 5303(c).

Proposed § 5.31(d), explaining that this section concerning statutory bars to benefits does not apply to certain government insurance programs, is new. It follows a statutory provision found at 38 U.S.C. 5303(d). Note that this exclusion applies only to statutory bars to benefits under 38 U.S.C. 5303. It does not affect, for example, the forfeiture of National Service Life Insurance under 38 U.S.C. 1911, "Forfeiture."

Current § 3.12(j) provides that:

> (j) No overpayment shall be created as a result of payments made after October 8, 1977, in cases in which the bar contained in paragraph (c)(6) of this section [relating to a statutory bar to VA benefit awards to individuals discharged under other than honorable conditions for being AWOL for 180 days or more] is for application. Accounts in payment status on or after October 8, 1977, shall be terminated at the end of the month in which it is determined that compelling circumstances do not exist, or April 7, 1978, whichever is the earliest. Accounts in suspense (either before or after October 8, 1977) shall be terminated on the date of last payment, or April 7, 1978, whichever is the earliest.

This material is grounded in provisions of section 5 of Public Law No. 95–126, 91 Stat. 1106 (1977); the same Public Law which, in section 1, amended what is now 38 U.S.C. 5303(a) to add the referenced statutory bar to VA benefits because of lengthy AWOLs. The material in the last two sentences of current § 3.12(j) was important transitional material at the time Public Law No. 95–126 became effective but is now obsolete. We propose to replace the § 3.12(j) material, in § 5.31(e), with simplified award termination provisions that take into account applicable procedural and notice provisions, described currently in § 3.105, "Revision of decisions." We propose to provide, in § 5.31(f), for the bar against overpayment creation by specifying that awards contrary to the statutory bar for lengthy AWOLs will be terminated on the date of last payment.

Proposed § 5.32, "Consideration of mitigating factors in absence without leave cases," deals with cases in which a service member was separated or discharged because of absence without authority (referred to here by the more common term "absence without leave" (AWOL)). One of the statutory bars to VA benefits under 38 U.S.C. 5303(a) is AWOL for a continuous period of at least 180 days. However, this subsection of the statute also provides for an exception where a claimant "demonstrates to the satisfaction of the Secretary [of Veterans Affairs] that there are compelling circumstances to warrant such prolonged unauthorized absence."

Current § 3.12(c)(6) sets up standards for determining whether there are "compelling circumstances" warranting a prolonged AWOL. It requires consideration of certain mitigating factors, such as reasons for being absent, when the service member was AWOL for 180 days or more. It does not provide for consideration of the same mitigating circumstances for lesser absences. Because it is illogical to be more lenient for greater offenses than for lesser ones, VA proposes in new § 5.32, under its general rulemaking authority in 38 U.S.C. 501(a), to make this policy applicable to all cases involving AWOL as the reason for discharge. The effect of this proposed change would be to explicitly permit consideration of factors mitigating AWOL in the context of character of discharge determinations as well as in conjunction with statutory bars to VA benefits. We believe that this is consistent with current VA practice.

As current § 3.12(c)(6) and proposed § 5.32(b) show, VA will consider such factors as how the situation appeared to the service member in light of the service member's age, cultural background, educational level and judgmental maturity in determining whether there were compelling circumstances for an unauthorized absence. However, we wish to be clear that VA does not judge whether compelling circumstances exist on the basis of a claimant's purely subjective viewpoint. Rather, VA looks at the record as a whole in evaluating whether compelling circumstances existed. *See Lane* v. *Principi,* 339 F.3d 1331 (Fed. Cir. 2003). Therefore, proposed § 5.32(b) notes that "VA will evaluate all of the relevant evidence of record in determining whether there are compelling circumstances to warrant unauthorized absence(s), including consideration of the following factors."

Proposed § 5.33 deals with insanity as a defense to the commission of acts leading to separation from service. This defense is available under 38 U.S.C.

5303(b) in cases involving statutory bars to VA benefits and in character of discharge determinations by regulation. The definition of insanity, now contained in § 3.354(a), will be revised and published for public comment later as part of this Project.

The next two proposed sections, §§ 5.34 and 5.35, state the rules related to the effect of discharge upgrades by boards for the correction of military records and discharge review boards on VA benefit eligibility determinations. Specifically, these rules concern whether VA benefits are barred by the character of a service member's discharge or because of statutory bars to benefits.

Current §§ 3.12 (f) and (g) provide guidance about the effect of discharge upgrades by discharge review boards on existing VA determinations based on a previous discharge, but they are not clear about the effect of such upgrades where VA is making the determination for the first time after the upgrade. We propose to address that shortcoming in § 5.35. The proposed section would also provide information about the effective dates of awards of VA benefits when benefit eligibility is established on the basis of a discharge upgrade by a board for the correction of military records or a discharge review board.

As current § 3.12 does, proposed § 5.35(d) provides that VA will not consider certain upgraded discharges issued by a discharge review board on or after October 8, 1977, in making character of discharge determinations unless certain enumerated statutory conditions for the board's review were met. (*See* 38 U.S.C. 5303(e)(1).) Proposed § 5.35(d)(2)(iii) clarifies that VA will accept a report of the service department concerned that the discharge review board met those conditions.

Proposed § 5.36 sets out material now contained in § 3.12(h) concerning the effect of certain special discharge upgrade programs in the 1970s. We have rewritten this regulation in an attempt to achieve greater clarity and to simplify the information concerning award terminations and a prohibition against the creation of overpayments.

Current § 3.12(i) provides that:

(i) No overpayments shall be created as a result of payments made after October 8, 1977, based on an upgraded honorable or general discharge issued under one of the programs listed in paragraph (h) of this section which would not be awarded under the standards set forth in paragraph (g) of this section. Accounts in payment status on or after October 8, 1977, shall be terminated the end of the month in which it is determined that the original other than honorable discharge was not issued under conditions other than dishonorable following notice from the appropriate discharge review board that the discharge would not have been upgraded under the standards set forth in paragraph (g) of this section, or April 7, 1978, whichever is the earliest. Accounts in suspense (either before or after October 8, 1977) shall be terminated on the date of last payment or April 7, 1978, whichever is the earliest.

This material is grounded in provisions of section 5 of Public Law No. 95–126, 91 Stat. 1106 (1977); the same Public Law which, in section 1, added what is now 38 U.S.C. 5303(e) concerning the effect of certain special discharge upgrade programs in the 1970s. The material in the last two sentences of current § 3.12(i) was important transitional material at the time Public Law No. 95–126 became effective, but is now obsolete. We propose to replace the § 3.12(i) material, in § 5.36(b), with simplified award termination provisions that take into account applicable procedural and notice provisions, described currently in § 3.105, "Revision of decisions." We propose to retain, in § 5.36(c), the bar against overpayment creation and specify that awards contrary to the section will be terminated on the date of last payment.

Proposed § 5.37, a proposed replacement for current § 3.13, concerns whether a service member has veteran status. That, in turn, depends (except for service members who die in service) upon whether the service member was discharged or released from active military service under other than dishonorable conditions. *See* 38 U.S.C. 101(2) (defining "veteran").

More specifically, proposed § 5.37 concerns a subset of the veteran status question. It typically arises under these circumstances: (1) A person enters military service for a fixed period of time, for example, a 4-year enlistment; (2) before the expiration of that fixed period of time, the person's service obligation is extended due to some change in military status; for example, an early discharge conditioned on immediate reenlistment, conversion from enlisted to officer status, a voluntary extension of service to gain some benefit, or an involuntary extension due to war or national emergency; (3) the person continues to serve honorably through the date when the original period of obligated service would have expired, but is not discharged or released on that date due to the intervening extension of the service obligation because of the change in military status; (4) after the date the period of service would have originally expired, but before discharge or release from the period of service to which the person became obligated upon the change in military status, the service member is involved in some incident that results in separation from service under dishonorable conditions.

Congress has determined that in such situations service members should be granted veteran status as though they had been discharged or released under other than dishonorable conditions at the time when the period of service they were first obligated to serve expired. The section implements 38 U.S.C. 101(18)(B), which was added by § 3 of Public Law 95–126, 91 Stat. 1106 (1977). The legislative history of this provision shows that Congress was attempting to correct an inequity caused when a discharge was not issued at the end of a service member's initial period of service because he or she agreed to extend their service beyond the initial period of obligation and, in some cases, decided or was offered the opportunity to change their military status. *See* H.R. Rep. No. 95–580, at 18, *reprinted in* 1977 U.S.C.C.A.N. 2844, 2861.

In drafting proposed § 5.37, we have extensively reorganized current § 3.13 and revised its language to make it more clearly reflect 38 U.S.C. 101(18), the statute's legislative history, and existing VA practice. We propose to title this new section, "Effect of extension of service obligation due to change in military status on eligibility for VA benefits," to clarify that the purpose of this section is to address situations when eligibility for VA benefits may be affected by a change in military status.

We note that even under the current regulation, there need not have been a formal discharge or release at the time military status changed; for example, a change from a Reserve to a Regular commission. The issue is not whether there was a discharge or release at the time of the change in military status, but rather due to the change in status, there was no discharge or release at the time the service member completed the period of service he or she was obligated to serve when they entered service.

We propose two definitions in § 5.37(b). The first is "change in military status." While the end result will be the same as under the current regulation, VA believes that the "change in status" terminology is much clearer and more accurately reflects 38 U.S.C. 101(18) and its legislative history than the "conditional discharge" language found in current § 3.13.

We propose to include a non-exclusive list of five examples of change in military status within this definition. The first four involve extensions of obligated service through reenlistment or acceptance of an appointment as a commissioned or warrant officer and changes between regular and reserve commissions. We propose to add voluntary or involuntary extensions of military service as a fifth example. Service may be extended on a voluntary or involuntary basis for a variety of reasons. These range from qualifying for financial incentives based on the length of certain tours to occurrences, such as suffering an injury at or near the separation of service date for which military medical care is required. Periods of service are sometimes involuntarily extended due to war or other national emergencies.

Because VA will determine the character of a service member's discharge or release upon the discharge or release from combined periods of service under certain circumstances, we also propose to define what we mean by "combined periods of service" in the context of this section. This is the second definition in proposed paragraph (b).

We propose to eliminate the various rules related to specific periods of war and peacetime service in current § 3.13(a)(1) through (3). These rules are based on VA regulations that predate the enactment of 38 U.S.C. § 101(18)(B) and are no longer necessary.

Proposed paragraph (c) states that VA will determine veteran status by the character of the final termination of the service member's combined periods of service if the combined periods of service terminate under honorable conditions. This is because there is no need to resort to the liberalizing provisions of 38 U.S.C. 101(18)(B) under such circumstances. The previously described sequence of events causing the potential inequity that 38 U.S.C. 101(18)(B) is intended to remedy would not occur because the service member was not "involved in some incident that results in separation from service under dishonorable conditions." If that extended service is terminated by a discharge under other than honorable conditions, the provisions of proposed paragraph (d), which implements 38 U.S.C. 101(18)(B), govern.

Further, we propose to omit language in current § 3.13(b) purporting to list an exception for death pension purposes; specifically "except that, for death pension purposes, § 3.3(b)(3) and (4) is controlling as to basic entitlement when the conditions prescribed therein are met." Proposed § 5.37 concerns veteran status, not pension eligibility rules, and is not inconsistent with those rules.

As part of our revision of these regulations we propose to reorganize current § 3.13(c), which we believe is unnecessarily confusing. It provides criteria for determining when VA will consider a service member to have been "unconditionally discharged or released from active military, naval or air service" "[d]espite the fact that no unconditional discharge may have been issued."

The term "unconditional discharge" is not one generally used by the various military departments and is not defined in the current regulations. Actually, the criteria listed are the criteria VA uses to determine whether a service member is eligible for VA benefits when he or she was not discharged or released at the expiration of the time he or she was obligated to serve at the beginning of a period of service because of an intervening change in military status that extends the service member's military obligation. We believe that use of "unconditional discharge" in the current regulation adds unnecessary complexity and have eliminated it in favor of a more accurate description in § 5.37(d), the proposed replacement for § 3.13(c). We have also clarified the effective date of the rules described in § 5.37(d). These rules are effective on and after October 8, 1977, the effective date of the provisions of Public Law 95–126 amending 38 U.S.C. 101(18).

Proposed new § 5.38, "Effect of a voided enlistment on eligibility for VA benefits," is based on current § 3.14. The first sentence of current § 3.14(b) states:

> Where an enlistment is voided by the service department because the person did not have legal capacity to contract for a reason other than minority (as in the case of an insane person) or because the enlistment was prohibited by statute (a deserter or person convicted of a felony), benefits may not be paid based on that service even though a disability was incurred during such service.

We propose to replace the example of "an insane person," in proposed § 5.38(b), with "a lack of mental capacity to contract." "A lack of mental capacity to contract" is the more customary way to describe this concept in contract law.

> The test for lack of capacity is generally said to be whether an individual lacks sufficient mental capacity to understand in a reasonable manner the nature of the transaction in which he or she is engaging, and to understand its consequences and effect upon his or her rights and interests.

53 Am. Jur. 2d *Mentally Impaired Persons* § 156 (1996).

This proposal also includes removal of sentences two and three of current § 3.14(a) and all of § 3.14(d). The second sentence of current § 3.14(a), "Benefits may not be paid, however, unless the discharge is held to have been under conditions other than dishonorable," is redundant. That concept is addressed in current § 3.12(a) and its proposed replacement, § 5.30.

The third sentence of current § 3.14(a) provides that: "Generally discharge for concealment of a physical or mental defect except incompetency or insanity which would have prevented enlistment will be held to be under dishonorable conditions." In our view, this provision is too rigid. Not every such concealment is with an intent to defraud the government. For example, an individual may conceal defects out of a strong desire to serve one's country in a time of war or other national crisis. Such an act may be misguided, but in VA's view it does not warrant the harsh results flowing from the current regulation. In other cases, a service member might serve with some distinction before a disqualifying preexisting physical or mental defect is discovered. The current regulation leaves VA with little flexibility to consider mitigating circumstances. VA believes that it can address this situation adequately under other provisions and has not included the quoted material in these proposed regulations.

The concept in current § 3.14(d) that VA is bound by a service department's determination that a discharge is honorable is included in the text of proposed § 5.30(c). The remaining material in current § 3.14(d) concerning aliens is, in substance, a cross reference to material in § 3.7(b) concerning certain veterans discharged for alienage whose service may be recognized for VA purposes (as opposed to the service of certain others so discharged who are statutorily barred from receiving VA benefits—*see* current § 3.12(c)(5) and proposed § 5.31(c)(6)). We do not believe that it is necessary to retain this reference, inasmuch as the referenced material is neither an exception to nor an amplification of the rule that VA is bound by a service department's determination that a discharge is honorable.

Minimum Service and Evidence of Service

The next portion of VA's service package includes removing current § 3.12a, "Minimum active-duty service requirement," and adding a proposed equivalent section, § 5.39, "Minimum active duty service requirement for VA benefits."

Paragraphs (d)(1) through (6) provide exclusions from the minimum active duty service requirement. One of these exclusions is based on 38 U.S.C. 5303A(b)(3)(C), which excludes "a person who has a disability that the Secretary has determined to be compensable under chapter 11 of this title." In paragraph 5.39(d)(4), we propose to clarify that a "compensable" disability means a service-connected disability evaluated as 10 percent or more disabling under 38 CFR part 4, Schedule for Rating Disabilities; a disability for which special monthly compensation is payable; or a disability that, together with one or more other disabilities, is compensable under current § 3.324, "Multiple noncompensable service-connected disabilities."

We believe that clarifying "compensable" disability to include veterans receiving special monthly compensation and those receiving a 10 percent evaluation for multiple noncompensable disabilities is fair to claimants and consistent with the Congressional intent of § 5303A. Although the legislative history regarding this issue is sparse, it speaks of including language similar to that in current § 3.12a(d)(3) in § 5303A(b)(3)(C) in order to distinguish § 5303A from a parallel statute of the Department of Defense. It appears that Congress intended to make sure that the minimum service requirement only applies to individuals with disabilities "so slight as to be rated as zero-percent disabling, and for which no compensation is payable." S.R. Rep. No. 97–153, 97th Cong., 1st Sess., at 41–42, reprinted in 1981 U.S.S.C.A.N. 1595, 1626. Therefore, consistent with Congressional intent, we propose to make it clear in § 5.39(d)(4) that veterans receiving compensation would be excluded from meeting the minimum service requirement.

Current § 3.12a(a)(1)(i), in discussing a requirement of 24-months of continuous active duty for eligibility for VA benefits, provides that "[n]on-duty periods that are excludable in determining the Department of Veterans Affairs benefit entitlement (*e.g.*, see § 3.15) are not considered as a break in service for continuity purposes but are to be subtracted from total time served." We propose in paragraph (e) to state the provisions regarding temporary breaks in service, currently found in § 3.15. However, because the minimum active duty service requirement in current § 3.12a, and its proposed replacement, only apply to persons who entered service in the early 1980's and thereafter, we are not including breaks that pertain to earlier time periods. We also propose to provide the same clarifications concerning time lost while under arrest and while serving a court martial sentence that appear in proposed § 5.21(b). See the discussion concerning proposed changes to § 5.21 for additional information.

Under current § 3.12a(e) and 38 U.S.C. 5303A(c), the dependents and survivors of a veteran who does not meet the minimum service requirement are also disqualified from VA benefits, except for benefits under chapter 19 (insurance) and chapter 37 (housing and small business loans) of 38 U.S.C. We propose to further clarify these exceptions in paragraph (f)(2) of proposed § 5.39. As specified in proposed § 5.39(d)(5), and 38 U.S.C. 5303A(b)(3)(D), the minimum service requirement does not bar certain non-compensation VA benefits for a service-connected disability, condition or death. We note this exception through a cross-reference to § 5.39(d)(5).

We also propose to state that the minimum service requirement does not bar an award of DIC based on the veteran's death in service. This is because, under 38 U.S.C. 5303A(b), the minimum service requirement applies only if a person is "discharged or released" before completing the required period of active duty. A veteran who dies in service never has the opportunity to be "discharged or released," so the requirements should not be applied in such a case. Of course the fact that an in-service death is not subject to the minimum service requirement of 38 U.S.C. 5303A does not mean that DIC may not be awarded for a service-connected death that occurs after service. However, 38 U.S.C. 5303A(c), and its proposed implementing regulation at § 5.39(f), would be considered in determining eligibility for DIC based on post-service death whereas an in-service death does not fall under 38 U.S.C. 5303A's minimum service requirement.

The final regulation in this proposed rulemaking is proposed § 5.40, "Service records as evidence of service and character of discharge that qualify for VA benefits." This is a reorganization of current § 3.203, written more concisely to make it more understandable and easier to apply.

VA now has a statutory duty to assist claimants in obtaining evidence to substantiate their claims. Among other things, 38 U.S.C. 5103A(c)(1) provides, with respect to a claim for disability compensation, that VA's assistance will include obtaining "[t]he claimant's service medical records and, if the claimant has furnished the Secretary information sufficient to locate such records, other relevant records pertaining to the claimant's active military, naval, or air service that are held or maintained by a governmental entity."

The specifics of how VA implements its duty to assist are currently located in 38 CFR 3.159. However, we wish to make the regulations we are updating and revising compatible with that duty. As an example, current § 3.203(a) is entitled "Evidence submitted by a claimant." This, or similar wording, could be taken to imply that VA will not grant a claim if the claimant does not submit evidence of his or her service. We do not wish to imply that VA will not assist in obtaining service records, nor do we wish to imply that claimants may not submit those records with their claims. Therefore, we propose to use more neutral language in this section and to shift the focus from who must submit the evidence of service to what kind of evidence of service VA will accept, whether submitted by or for a claimant or obtained by VA.

Because paragraph (b) and the second sentence of paragraph (c) of current § 3.203 address additional requirements for eligibility for pension or burial benefits, we propose to move these provisions to the appropriate portions of new part 5 dealing with those benefits and to omit this information from this proposed new section.

Proposed paragraphs (a) and (b) state the rules pertaining to what evidence of service is acceptable to VA and the kinds of information that evidence must contain. Paragraph (a) also clarifies that the list of acceptable documents is not all-inclusive. Currently, § 3.203 indicates that the evidence should contain "needed information as to length, time and character of service." In this revision, we propose to change "time" of service to the more specific "dates of service."

We propose to clarify this regulation by specifying in paragraph (c) when verification by the service department is not required. Proposed paragraph (d) would include circumstances when verification from the service department is required. Along with the circumstances listed in current § 3.203(c), we propose to add paragraph (d)(3), which provides that VA will verify service if there is a material discrepancy in the evidence of record. This would, for example, cover situations in which documents concerning service are in conflict or there is credible testimony concerning service that conflicts with other evidence of record.

Endnote Regarding Removals (Deletions) From Part 3 of 38 CFR

This is an advance notice of our intention to remove current §§ 3.2, 3.6, 3.7, 3.12, 3.12a, and 3.13 through 3.15 and portions of §§ 3.203 and 3.400. We are not proposing these changes in part 3 at this time. Readers, however, are invited to comment on these removals at this time. We will propose these part 3 changes and the removal of all of part 3, in the last NPRM concerning the proposed part 5 compensation and pension regulations. VA plans to publish all of the subparts of part 5 for public comment over time. After public comments for all of the proposed subparts have been reviewed and considered, VA intends to remove all of part 3, concurrent with the implementation of part 5.

Paperwork Reduction Act

This document contains no provisions constituting a collection of information under the Paperwork Reduction Act (44 U.S.C. 3501–3521).

Regulatory Flexibility Act

The Secretary hereby certifies that this regulatory amendment will not have a significant economic impact on a substantial number of small entities as they are defined in the Regulatory Flexibility Act (RFA), 5 U.S.C. 601–612. This amendment would not affect any small entities. Only VA beneficiaries could be directly affected. Therefore, pursuant to 5 U.S.C. 605(b), this amendment is exempt from the initial and final regulatory flexibility analysis requirements of sections 603 and 604.

Executive Order 12866

This document has been reviewed by the Office of Management and Budget under Executive Order 12866.

Unfunded Mandates

The Unfunded Mandates Reform Act requires, at 2 U.S.C. 1532, that agencies prepare an assessment of anticipated costs and benefits before developing any rule that may result in an expenditure by State, local, or tribal governments, in the aggregate, or by the private sector of $100 million or more in any given year. This rule would have no such effect on State, local, or tribal governments, or the private sector.

Catalog of Federal Domestic Assistance Numbers

The catalog of Federal Domestic Assistance program numbers for this proposal are 64.100–102, 64.104–110, 64.115, and 64.127.

List of Subjects in 38 CFR Part 5

Administrative practice and procedure, Claims, Disability benefits, Health care, Pensions, Radioactive materials, Veterans, Vietnam.

Approved: November 6, 2003.

Anthony J. Principi,

Secretary of Veterans Affairs.

For the reasons set out in the preamble, VA proposes to amend 38 CFR chapter I by adding part 5 to read as follows:

PART 5 COMPENSATION, PENSION, BURIAL AND RELATED BENEFITS

Subpart A—[Reserved]

Subpart B—Service Requirements for Veterans

Periods of War and Types of Military Service

Authority: 38 U.S.C. 501(a) and as noted in specific sections.

Subpart A—[Reserved]

Subpart B—Service Requirements for Veterans

Periods of War and Types of Military Service

§ 5.20 Dates of periods of war.

This section explains what periods of service VA recognizes as wartime service, beginning with the Mexican border period. *See* 38 U.S.C. 101 for information concerning earlier periods of war.

Period	Dates	Exceptions/special rules	Authority
(a) Mexican Border Period.	May 9, 1916, through April 5, 1917	Applies to a veteran who served in Mexico, or on the borders of Mexico, or in the waters adjacent to Mexico during the stated period.	38 U.S.C. 101(30).
(b) World War I	April 6, 1917, through November 11, 1918	(1) April 6, 1917, through April 1, 1920, for United States armed forces serving in Russia.	38 U.S.C. 101(7), 1101(2)(A), 1501(2).

Period	Dates	Exceptions/special rules	Authority
		(2) April 6, 1917, through July 1, 1921, for veterans who served in the active military, naval, or air service after April 5, 1917, and before November 12, 1918. This extension is limited to matters concerning benefits under 38 U.S.C. chapter 11 (service-connected disability compensation, death compensation, and benefits for persons disabled by VA medical treatment or during VA vocational rehabilitation or compensated work therapy) and benefits under 38 U.S.C. chapter 15 ("Pension for Non-Service-Connected Disability or Death or for Service").	
(c) World War II	December 7, 1941, through December 31, 1946.	World War II service also includes any period of continuous service after December 31, 1946, and before July 26, 1947, if that period of service began before January 1, 1947. This extension is limited to matters concerning benefits under 38 U.S.C. chapter 11 (service-connected disability compensation, death compensation, and benefits for persons disabled by VA medical treatment or during VA vocational rehabilitation, or compensated work therapy).	38 U.S.C. 101(8), 1101(2)(B).
(d) Korean Conflict	June 27, 1950, through January 31, 1955	None	38 U.S.C. 101(9).
(e) Vietnam Era	August 5, 1964, through May 7, 1975	The Vietnam Era also includes February 28, 1961, through August 4, 1964, in the case of a veteran who served in the Republic of Vietnam during that period.	38 U.S.C. 101(29).
(f) Persian Gulf War	August 2, 1990, through a date to be prescribed by Presidential proclamation or by law.	....	38 U.S.C. 101(33).
(g) Future periods of war.	Beginning on the date of any future declaration of war by the Congress and ending on a date prescribed by Presidential proclamation or concurrent resolution of the Congress.	....	38 U.S.C. 101(11).

§ 5.21 Service VA recognizes as active military service.

(a) Active military service includes:

(1) Active duty. *See* § 5.22, "Service VA recognizes as active duty."

(2) The service of individuals certified by the Secretary of Defense as serving on active military service. *See* § 5.27.

(3) The service of individuals and groups listed in § 5.28.

(4) Active duty for training during which the individual was disabled or died from a disease or injury incurred or aggravated in line of duty.

(5) Inactive duty training during which the individual was disabled or died from an injury incurred or aggravated in line of duty or from an acute myocardial infarction, a cardiac arrest, or a cerebrovascular accident.

(6) Active or Reserve duty for persons who were injured or died while assigned to the Postmaster General for the aerial transportation of mail from February 10, 1934, through March 26, 1935.

(b) In determining the period of active military service for service-connected or nonservice-connected benefits, VA will not count:

(1) Time spent on industrial, agricultural, or indefinite furlough;

(2) Time lost when absent without leave and without pay;

(3) Time while under arrest without a subsequent acquittal or dismissal of charges;

(4) Time during desertion; or

(5) Subject to 10 U.S.C. 875 (concerning the restoration of rights, privileges, and property affected by certain court-marital sentences that are set aside or disapproved), time while serving a sentence of confinement imposed by a court-martial.

(Authority: 38 U.S.C. 101(24), 501(a). Section 5.21(a)(6) also issued under Pub. L. No. 73–140, 48 Stat. 508 (1934))

§ 5.22 Service VA recognizes as active duty.

(a) Active duty means:

(1) Full-time duty in the Armed Forces, other than active duty for training.

(2) Certain duty performed by:

(i) Reserve and National Guard members. *See* § 5.23.

(ii) Armed Services Academy cadets, midshipmen, attendees at the preparatory schools of the Armed Services Academies, and Senior Reserve Officers' Training Corps members. *See* § 5.24.

(iii) Commissioned officers of the Public Health Service, Coast and Geodetic Survey and its successor agencies, and temporary members of the Coast Guard Reserves. *See* § 5.25.

(3) Certain service of individuals ordered to service but who did not serve. *See* § 5.26.

(b) Active duty continues until midnight of the date of discharge or release from active duty.

(c) Active duty includes certain travel as provided in § 5.29, "Circumstances under which certain travel periods may be classified as military service."

(Authority: 38 U.S.C. 101(21))

§ 5.23 How VA classifies Reserve and National Guard duty.

(a) *Reserves.* (1) *Active duty.* Full-time duty in the Armed Forces performed by a Reservist, other than active duty for training, is active duty.

(2) *Active duty for training.* Full-time duty in the Armed Forces performed by

a Reservist for training purposes is active duty for training.

(3) *Inactive duty training.* Duty that is not full-time duty and that the Secretary concerned prescribes for a Reservist to participate in as a regular period of instruction or appropriate duty is inactive duty training. (*See* 37 U.S.C. 206, "Reserves; members of National Guard: inactive-duty training.") Special additional duties authorized for a Reservist by an authority designated by the Secretary concerned and performed on a voluntary basis in connection with prescribed training maintenance activities of the unit to which the Reservist is assigned is also inactive duty training.

(b) *National Guard.* (1) *Active duty.* Full-time duty in the Armed Forces performed by a member of the National Guard serving under title 10, United States Code, other than active duty for training, is active duty.

(2) *Active duty for training.* Full-time duty performed by a member of the National Guard of any State under any of the following six circumstances is active duty for training:

(i) When detailed as a rifle instructor for civilians (*See* 32 U.S.C. 316);

(ii) During required drills and field exercises (*See* 32 U.S.C. 502);

(iii) While participating in field exercises as directed by the Secretary of the Army or the Secretary of the Air Force (*See* 32 U.S.C. 503);

(iv) While attending schools or small arms competitions as prescribed by the Secretary of the Army or the Secretary of the Air Force (*See* 32 U.S.C. 504);

(v) While attending any service school (except the United States Military Academy or the United States Air Force Academy), or attached to an organization of the Army or the Air Force for routine practical instruction during field training or other outdoor exercise. (*See* 32 U.S.C. 505); or

(vi) When performed under prior provisions of law that correspond to 32 U.S.C. 316, 502, 503, 504, or 505, for each of paragraphs (b)(2)(i) through (v) of this section.

(3) *Inactive duty training.* Duty, other than full-time duty, performed by a member of the National Guard of any State under any of the following six circumstances is inactive duty training:

(i) When detailed as a rifle instructor for civilians (*See* 32 U.S.C. 316);

(ii) During required drills and field exercises (*See* 32 U.S.C. 502);

(iii) While participating in field exercises as directed by the Secretary of the Army or the Secretary of the Air Force (*See* 32 U.S.C. 503);

(iv) While attending schools or small arms competitions as prescribed by the Secretary of the Army or the Secretary of the Air Force (*See* 32 U.S.C. 504);

(v) While attending any service school (except the United States Military Academy or the United States Air Force Academy), or attached to an organization of the Army or the Air Force for routine practical instruction during field training or other outdoor exercise (*See* 32 U.S.C. 505); or

(vi) When performed under prior provisions of law that correspond to 32 U.S.C. 316, 502, 503, 504, or 505, for each of paragraphs (b)(3)(i) through (v) of this section.

(4) *Exception.* Inactive duty training does not include work or study performed in connection with correspondence courses, or attendance at an educational institution in an inactive status.

(c) *Certain travel periods.* For issues involving travel of a reservist or member of the National Guard, *see* § 5.29, "Circumstances under which certain travel periods may be classified as military service."

(Authority: 38 U.S.C. 101(21)–(23), 106, and 501(a))

§ 5.24 How VA classifies duty performed by Armed Services Academy cadets, midshipmen, attendees at the preparatory schools of the Armed Services Academies, and Senior Reserve Officers' Training Corps members.

(a) *Service as a cadet or midshipman.* Service as a cadet at the United States Air Force Academy, United States Military Academy, or United States Coast Guard Academy, or as a midshipman at the United States Naval Academy qualifies as active duty. The period of such duty continues until midnight of the date of discharge or release from the respective service academy.

(b) *Preparatory school attendance.* (1) *Active duty.* Attendance at the preparatory schools of the United States Air Force Academy, the United States Military Academy, or the United States Naval Academy is considered active duty if:

(i) The individual was an enlisted active-duty member who was reassigned to a preparatory school without a release from active duty; or

(ii) The individual has a commitment to perform active duty in the Armed Forces that would be binding upon disenrollment from the preparatory school.

(2) *Active duty for training.* Except as provided in paragraph (b)(1)(ii) of this section, attendance at the preparatory schools of the United States Air Force Academy, the United States Military Academy, or the United States Naval Academy by an individual who enters the preparatory school directly from the Reserves, National Guard, or civilian life is active duty for training.

(c) *Senior Reserve Officers' Training Corps.* (1) *Active duty for training.* Duty performed by a member of a Senior Reserve Officers' Training Corps program when ordered to duty for the purpose of training or a practice cruise under statutes and regulations governing the Armed Forces conduct of the Senior Reserve Officers' Training Corps is active duty for training.

(Authority: 10 U.S.C. chapter 103)

(i) This paragraph (c)(1) is effective October 1, 1982, for death or disability resulting from disease or injury that occurred on or after October 1, 1982.

(ii) This paragraph (c)(1) is effective October 1, 1983, for death or disability resulting from disease or injury that occurred on or before September 30, 1982.

(iii) For duty on or after October 1, 1988, the duty must be a prerequisite to the member being commissioned and must be at least four continuous weeks long.

(2) *Inactive duty training.* Training by a member of, or applicant for membership (a student enrolled, during a semester or other enrollment term, in a course that is part of Reserve Officers' Training Corps instruction at an educational institution) in the Senior Reserve Officers' Training Corps prescribed under 10 U.S.C. Chapter 103 ("Senior Reserve Officers' Training Corps") is inactive duty training.

(3) *Drills.* Time spent by members of the Senior Reserve Officers' Training Corps in drills as part of their activities as members of the corps is not active military service.

(d) *Travel.* For issues involving travel under this section, *see* § 5.29, "Circumstances under which certain travel periods may be classified as military service."

(Authority: 38 U.S.C. 101, 106, and 501(a))

§ 5.25 How VA classifies service in the Public Health Service, in the Coast and Geodetic Survey and its successor agencies, and of temporary members of the Coast Guard Reserve.

(a) *Public Health Service.* (1) *Active duty.* (i) Full-time duty, other than for training purposes, as a commissioned officer of the Regular or Reserve Corps of the Public Health Service is active duty if performed:

(A) On or after July 29, 1945;

(B) Before July 29, 1945, under circumstances affording entitlement to full military benefits; or

(C) At any time, for the purposes of dependency and indemnity compensation.

(ii) Such active duty continues until midnight of the date of discharge or release from active duty.

(2) *Active duty for training.* Full-time duty for training purposes performed as a commissioned officer of the Reserve Corps of the Public Health Service is active duty for training if performed:

(i) On or after July 29, 1945;

(ii) Before July 29, 1945, under circumstances affording entitlement to full military benefits, as determined by the Secretary of the Department of Defense; or

(iii) At any time, for the purposes of dependency and indemnity compensation.

(3) *Inactive duty training.* Either of the following kinds of service is inactive duty training:

(i) Duty, other than full-time duty, prescribed for commissioned officers of the Reserve Corps of the Public Health Service by the Secretary of Health and Human Services under 37 U.S.C. 206 (Reserves; members of National Guard: Inactive-duty training) or any other provision of law; or

(ii) Special additional duties authorized for commissioned officers of the Reserve Corps of the Public Health Service by an authority designated by the Secretary of Health and Human Services and performed by them on a voluntary basis in connection with the prescribed training or maintenance activities of the units to which they are assigned.

(b) *Coast and Geodetic Survey and successor agencies.* (1) *Active duty.* Full-time duty as a commissioned officer in the Coast and Geodetic Survey and its successor agencies, the Environmental Science Services Administration and the National Oceanic and Atmospheric Administration, is active duty if performed:

(i) On or after July 29, 1945;

(ii) Before July 29, 1945, while on transfer to one of the Armed Forces;

(iii) Before July 29, 1945, in time of war or National emergency declared by the President, while assigned to duty on a project for one of the Armed Forces in an area that the Secretary of Defense has determined to be of immediate military hazard;

(iv) In the Philippine Islands on December 7, 1941, and continuously in such islands thereafter until July 29, 1945; or

(v) At any time for purposes of dependency and indemnity compensation.

(2) Such active duty continues until midnight of the date of discharge or release from active duty.

(c) *Temporary member of the Coast Guard Reserve.* Duty performed as a temporary member of the Coast Guard Reserve is not active duty for training or inactive duty training.

(d) *Travel.* For issues involving travel by members of the Public Health Service, members of the Coast and Geodetic Survey and its successor agencies, or reservists under this section, see § 5.29, "Circumstances under which certain travel periods may be classified as military service."

(Authority: 38 U.S.C. 101, 106, and 501(a))

§ 5.26 Circumstances where persons ordered to service, but who did not serve, are considered to have performed active duty.

(a) *Persons included.* The persons described in paragraph (a) of this section who meet the requirements of paragraphs (a) and (b) of this section will be considered to have performed active duty for entitlement to VA benefits.

(1) *Volunteers.* Volunteers are included, provided they have applied for enlistment or enrollment in the active military service and have been provisionally accepted and directed or ordered to report to a place for final acceptance into the service.

(2) *Draftees.* Persons selected or drafted for enrollment in the active military service are included if they report, before being rejected for service, according to a call from their local draft board.

(3) *National Guard.* Members of the National Guard are included when they have been called into Federal active service, but have not yet been enrolled in such service, and when reporting to a designated rendezvous.

(b) *Injury or disease.* This section applies only if a person described in paragraph (a) of this section suffers an injury, or contracts a disease, in line of duty while going to, coming from, or at a place designated for final acceptance or entry upon active duty. This applies to a draftee or selectee when reporting for preinduction examination or for final induction on active duty. This section does not apply to an injury or disease suffered during a period of inactive duty status or period of waiting after a final physical examination and prior to beginning the trip to report for induction. The injury or disease must be due to some factor relating to compliance with proper orders.

(Authority: 38 U.S.C. 106(b))

§ 5.27 Individuals and groups designated by the Secretary of Defense as having performed active military service.

(a) *Designation by the Secretary of Defense.* Service performed by certain persons and groups that served the Armed Forces of the United States in a capacity that was considered civilian employment or contractual service under Public Law 95–202, is active military service for the purpose of VA benefits provided that the Secretary of Defense, or his or her designee, certifies this as active military service and issues a discharge under honorable conditions.

(b) *Individuals and groups included.* The Secretary of Defense, or his or her designee, has certified as active military service the service of the following individuals and groups:

(1) American Merchant Marine in oceangoing service, during the Period of Armed Conflict, December 7, 1941, to August 15, 1945. Recognized effective January 19, 1988.

(2) The approximately 50 Chamorro and Carolinian former native policemen who received military training in the Donnal area of central Saipan and were placed under the command of Lt. Casino of the 6th Provisional Military Police Battalion to accompany United States Marines on active, combat-patrol activity from August 19, 1945, to September 2, 1945. Recognized effective September 30, 1999.

(3) Civilian Crewmen of the United States Coast and Geodetic Survey (USCGS) vessels, who performed their service in areas of immediate military hazard while conducting cooperative operations with and for the U.S. Armed Forces within a time frame of December 7, 1941, to August 15, 1945. Qualifying USCGS vessels specified by the Secretary of Defense, or his or her designee, are the Derickson, Explorer, Gilbert, Hilgard, E. Lester Jones, Lydonia, Patton, Surveyor, Wainwright, Westdahl, Oceanographer, Hydrographer, and Pathfinder. Recognized effective April 8, 1991.

(4) Civilian employees of Pacific Naval Air Bases who actively participated in Defense of Wake Island during World War II. Recognized effective January 22, 1981.

(5) Civilian Navy Identification Friend or Foe (IFF) Technicians, who served in the Combat Areas of the Pacific during World War II (December 7, 1941, to August 15, 1945). Recognized effective August 2, 1988.

(6) Civilian personnel assigned to the Secret Intelligence Element of the Office of Strategic Services (OSS). Recognized effective December 27, 1982.

(7) Engineer Field Clerks (WWI). Recognized effective August 31, 1979.

(8) Guam Combat Patrol. Recognized effective May 10, 1983.

(9) Honorably discharged members of the American Volunteer Group (Flying Tigers), who served during the Period December 7, 1941, to July 18, 1942. Recognized effective May 3, 1991.

(10) Honorably discharged members of the American Volunteer Guard, Eritrea Service Command, who served during the Period June 21, 1942, to March 31, 1943. Recognized effective June 29, 1992.

(11) Male Civilian Ferry Pilots. Recognized effective July 17, 1981.

(12) The Operational Analysis Group of the Office of Scientific Research and Development, Office of Emergency Management, which served overseas with the U.S. Army Air Corps from December 7, 1941, through August 15, 1945. Recognized effective August 27,1999.

(13) Quartermaster Corps Female Clerical Employees serving with the AEF (American Expeditionary Forces) in World War I. Recognized effective January 22, 1981.

(14) Quartermaster Corps Keswick Crew on Corregidor (WWII). Recognized effective February 7, 1984.

(15) Reconstruction Aides and Dietitians in World War I. Recognized effective July 6, 1981.

(16) Signal Corps Female Telephone Operators Unit of World War I. Recognized effective May 15, 1979.

(17) Three scouts/guides, Miguel Tenorio, Penedicto Taisacan, and Cristino Dela Cruz, who assisted the U.S. Marines in the offensive operations against the Japanese on the Northern Mariana Islands from June 19, 1944, through September 2, 1945. Recognized effective September 30, 1999.

(18) U.S. civilian employees of American Airlines, who served overseas as a result of American Airlines' contract with the Air Transport Command during the Period December 14, 1941, through August 14, 1945. Recognized effective October 5, 1990.

(19) U.S. civilian female employees of the U.S. Army Nurse Corps while serving in the defense of Bataan and Corregidor during the Period January 2, 1942, to February 3, 1945. Recognized effective December 13, 1993.

(20) U.S. Civilian Flight Crew and Aviation Ground Support Employees of Braniff Airways, who served overseas in the North Atlantic or under the jurisdiction of the North Atlantic Wing, Air Transport Command (ATC), as a result of a contract with the ATC during the Period February 26, 1942, through August 14, 1945. Recognized effective June 2, 1997.

(21) U.S. Civilian Flight Crew and Aviation Ground Support Employees of Consolidated Vultree Aircraft Corporation (Consairway Division), who served overseas as a result of a contract with the Air Transport Command during the Period December 14, 1941, through August 14, 1945. Recognized effective June 29, 1992.

(22) U.S. Civilian Flight Crew and Aviation Ground Support Employees of Northeast Airlines Atlantic Division, who served overseas as a result of Northeast Airlines' Contract with the Air Transport Command during the Period December 7, 1941, through August 14, 1945. Recognized effective June 2, 1997.

(23) U.S. Civilian Flight Crew and Aviation Ground Support Employees of Northwest Airlines, who served overseas as a result of Northwest Airline's contract with the Air Transport Command during the Period December 14, 1941, through August 14, 1945. Recognized effective December 13, 1993.

(24) U.S. Civilian Flight Crew and Aviation Ground Support Employees of Pan American World Airways and Its Subsidiaries and Affiliates, who served overseas as a result of Pan American's Contract with the Air Transport Command and Naval Air Transport Service during the Period December 14, 1941, through August 14, 1945. Recognized effective July 16, 1992.

(25) U.S. Civilian Flight Crew and Aviation Ground Support Employees of Transcontinental and Western Air (TWA), Inc., who served overseas as a result of TWA's contract with the Air Transport Command during the Period December 14, 1941, through August 14, 1945. The "Flight Crew" includes pursers. Recognized effective May 13, 1992.

(26) U.S. Civilian Flight Crew and Aviation Ground Support Employees of United Air Lines (UAL), who served overseas as a result of UAL's contract with the Air Transport Command during the Period December 14, 1941, through August 14, 1945. Recognized effective May 13, 1992.

(27) U.S. civilian volunteers, who actively participated in the Defense of Bataan. Recognized effective February 7, 1984.

(28) U.S. civilians of the American Field Service (AFS), who served overseas operationally in World War I during the Period August 31, 1917, to January 1, 1918. Recognized effective August 30, 1990.

(29) U.S. civilians of the American Field Service (AFS), who served overseas under U.S. Armies and U.S. Army Groups in World War II during the Period December 7, 1941, through May 8, 1945. Recognized effective August 30, 1990.

(30) U.S. Merchant Seamen who served on blockships in support of Operation Mulberry. Recognized effective October 18, 1985.

(31) Wake Island Defenders from Guam. Recognized effective April 7, 1982.

(32) Women's Air Forces Service Pilots (WASP). Recognized effective November 23, 1977.

(33) Women's Army Auxiliary Corps (WAAC). Recognized effective March 18, 1980.

(c) *Effective dates of awards.* (1) *Scope.* Paragraph (c) of this section establishes the effective date of an award of any of the following benefits based on service in a group listed in this section:

(i) Pension;

(ii) Compensation;

(iii) Dependency and indemnity compensation; and

(iv) Monetary allowances for a child of:

(A) A Vietnam veteran under § 3.814 of this chapter, "Monetary allowance under 38 U.S.C. chapter 18 for an individual suffering from spina bifida whose biological father or mother is or was a Vietnam veteran;"

(B) A Vietnam veteran under § 3.815 of this chapter, "Monetary allowance under 38 U.S.C. chapter 18 for an individual with disability from covered birth defects whose biological mother is or was a Vietnam veteran; identification of covered birth defects;"

(C) A veteran of covered service in Korea under 38 U.S.C. 1821, "Benefits for children of certain Korea service veterans born with spina bifida."

(2) *Claim received one year or less after the effective date of recognition.* If VA receives the claim within one year of the effective date of recognition, then the effective date of the award is the later of:

(i) The date entitlement arose, as defined in [regulation that will be published in a future Notice of Proposed Rulemaking concerning proposed subpart C of this part] of this part, or

(ii) The effective date of recognition.

(3) *Claim received more than one year after the effective date of recognition.* If VA receives the claim more than one year after the effective date of recognition, the effective date of the award or increase is the later of:

(i) The date entitlement arose, as defined in [regulation that will be published in a future Notice of Proposed Rulemaking concerning proposed subpart C of this part] of this part, or

(ii) One year prior to the date of receipt of the claim.

(4) *Effective dates for awards based on a review on VA's initiative one year or less after the effective date of recognition.* If VA awards benefits one year or less after the effective date of recognition, the effective date of the award is the later of:

(i) The date entitlement arose, as defined in [regulation that will be published in a future Notice of Proposed Rulemaking concerning proposed subpart C of this part] of this part, or

(ii) The effective date of recognition.

(5) *Effective dates for awards based on a review on VA's initiative more than one year after the effective date of the change.* If VA awards benefits more than one year after the effective date of recognition, the effective date of the award is the later of:

(i) The date entitlement arose, as defined in [regulation that will be published in a future Notice of Proposed Rulemaking concerning proposed subpart C of this part] of this part, or

(ii) One year prior to the date of the VA rating decision awarding the benefit, or if no rating decision is required, one year prior to the date VA otherwise determines that the claimant is entitled to the benefit.

(Authority: 38 U.S.C. 501(a), 1832(b)(2), 5110(g); Sec. 401, Pub. L. 95–202, 91 Stat. 1449, 1450)

§ 5.28 Other individuals and groups designated as having performed active military service.

The following individuals and groups are considered to have performed active military service:

(a) *Alaska Territorial Guard during World War II.* (1) Service in the Alaska Territorial Guard during World War II for any individual who was honorably discharged as determined by the Secretary of Defense is included.

(2) Benefits cannot be paid for this service for any period prior to August 9, 2000.

(b) *Army field clerks.* Army field clerks are included as enlisted men.

(c) *Army Nurse Corps, Navy Nurse Corps, and female dietetic and physical therapy personnel.* Army Nurse Corps, Navy Nurse Corps, and female dietetic and physical therapy personnel are included, as follows:

(1) *Nurse Corps.* Female Army and Navy nurses on active service under order of the service department; or

(2) *Female dietetic and physical therapy personnel.* Female dietetic and physical therapy personnel, excluding students and apprentices, appointed with relative rank on or after December 22, 1942, or commissioned on or after June 22, 1944.

(d) *Aviation camps.* Students who were enlisted men in Aviation camps during World War I are included.

(e) *Coast Guard.* Active service in the Coast Guard on or after January 28, 1915, while under the jurisdiction of the Treasury Department, the Navy Department, the Department of Transportation, or the Department of Homeland Security is included. This does not include temporary members of the Coast Guard Reserves.

(f) *Contract surgeons.* Contract surgeons are included for compensation and DIC, if the disability or death was the result of disease or injury contracted in line of duty during a period of war while actually performing the duties of assistant surgeon or acting assistant surgeon with any military force in the field, or in transit, or in a hospital.

(g) *Field clerks, Quartermaster Corps.* Field clerks of the Quartermaster Corps are included as enlisted personnel.

(h) *Lighthouse service personnel.* Lighthouse service personnel who were transferred to the service and jurisdiction of the War or Navy Departments by Executive order under the Act of August 29, 1916, are included. Effective July 1, 1939, service was consolidated with the Coast Guard.

(i) *Male nurses.* Male nurses who were enlisted in a Medical Corps are included.

(j) *Persons previously having a pensionable or compensable status.* Persons having a pensionable or compensable status prior to January 1, 1959, are included.

(Authority: 38 U.S.C. 1152, 1504)

(k) *Philippine Scouts and others. See* § 3.40.

(l) *Revenue Cutter Service.* The Revenue Cutter Service is included while serving under direction of the Secretary of the Navy in cooperation with the Navy. Effective January 28, 1915, the Revenue Cutter Service was merged into the Coast Guard.

(m) *Russian Railway Service Corps.* Service during World War I in the Russian Railway Service Corps as certified by the Secretary of the Army is included.

(n) *Training camps.* Members of training camps authorized by section 54 of the National Defense Act (Pub. L. No. 64–85), are included, except for members of Student Army Training Corps Camps at the Presidio of San Francisco; Plattsburg, New York; Fort Sheridan, Illinois; Howard University, Washington, DC; Camp Perry, Ohio; and Camp Hancock, Georgia, from July 18, 1918, to September 16, 1918.

(o) *Women's Army Corps (WAC).* Service in the WAC on or after July 1, 1943, is included.

(p) *Women's Reserve of Navy, Marine Corps, and Coast Guard.* Service in the Women's Reserve of the Navy, Marine Corps, and Coast Guard is included and provides the same benefits as members of the Officers Reserve Corps or enlisted men of the United States Navy, Marine Corps, or Coast Guard.

(Authority: 38 U.S.C. 101, 106, and 501(a))

§ 5.29 Circumstances under which certain travel periods may be classified as military service.

(a) *Active duty.* (1) *Travel time to and from active duty.* Travel to or from any period of active duty is active duty if the travel is authorized by the Secretary concerned.

(2) *Travel on discharge or release.* Travel time consisting of the period between the date of discharge or release and arrival home by the most direct route is active duty.

(3) *Persons ordered to service but who did not serve.* For information about the travel of certain persons ordered to service who did not serve, *see* § 5.26(b).

(b) *Active duty for training or inactive duty training*—(1) *Travel time for active duty for training or inactive duty training.* Any individual proceeding directly to, or returning directly from, a period of active duty for training or inactive duty training will be considered to be on active duty for training or inactive duty training if the individual was:

(i) Authorized or required by competent authority designated by the Secretary concerned to perform such duty, and

(ii) Disabled or died from an injury, an acute myocardial infarction, a cardiac arrest, or a cerebrovascular accident incurred during that travel.

(2) *Determination of status.* VA will determine whether such an individual was authorized or required to perform such duty and whether the individual was disabled or died from an injury, an acute myocardial infarction, a cardiac arrest, or a cerebrovascular accident incurred during that travel. In making these determinations, VA will take into consideration:

(i) The hour at which the individual began to proceed to or return from the duty;

(ii) The hour at which the individual was scheduled to arrive for, or at which the individual ceased to perform, such duty;

(iii) The method of travel employed;

(iv) The itinerary;

(v) The manner in which the travel was performed; and

(vi) The immediate cause of disability or death.

(3) *Burden of proof.* Whenever any claim is filed alleging that the claimant is entitled to benefits by reason of travel for active duty for training or inactive duty training, the burden of proof shall be on the claimant.

(Authority: 38 U.S.C. 101(21) and (22), 106(c) and (d))

Service Creditable for VA Benefits

§ 5.30 How VA determines if service qualifies for VA benefits.

(a) *Purpose.* Except for service members who died in service, a requirement for veteran status is discharge or release under other than dishonorable conditions. *See* § 3.1(d) (defining "veteran"). This section sets out how VA determines whether the service member's discharge or release was under other than dishonorable conditions.

(b) *Limitation to period of service concerned.* (1) *General rule.* A determination under this section that a service member was discharged or released under dishonorable conditions applies only to the period of service to which the discharge or release applies. It does not preclude veteran status with respect to other periods of service from which the service member was discharged or released under other than dishonorable conditions. *See also* § 5.37 (concerning certain cases where a service member was not discharged or released at the end of the period of time for which he or she was obligated to serve when entering a period of service because of a change in his or her military status during that period of service).

(2) *Forfeiture not precluded.* The provisions of paragraph (b)(1) of this section do not preclude forfeiture of VA benefits under 38 U.S.C. 6103, "Forfeiture for fraud," under 38 U.S.C. 6104, "Forfeiture for treason," under 38 U.S.C. 6105, "Forfeiture for subversive activities," or under similar statutes governing forfeiture of VA benefits.

(c) *Discharges and releases VA recognizes as being under other than dishonorable conditions.* For purposes of making determinations concerning character of discharge for VA purposes, a military discharge that is characterized by the service department as being either honorable or under honorable conditions is binding on VA. Subject to § 5.36 (concerning certain special 1970s-era discharge upgrades), any of the following is a discharge or release under other than dishonorable conditions for VA purposes:

(1) An honorable discharge.

(2) A general discharge under honorable conditions.

(3) An uncharacterized administrative entry level separation in the case of separation of enlisted personnel based on administrative proceedings begun on or after October 1, 1982.

(d) *Discharges VA recognizes as being under dishonorable conditions.* A dishonorable discharge is a discharge under dishonorable conditions for VA purposes, except as provided in § 5.33, "Insanity as a defense to acts leading to a discharge or dismissal from the service which might be disqualifying for VA benefits."

(e) *Discharges and releases for which VA will make the character of discharge determination.* Subject to § 5.36 (concerning certain special 1970s-era discharge upgrades), VA will determine whether the following types of discharges are discharges under other than dishonorable conditions for VA purposes, based on the facts and circumstances surrounding separation:

(1) An other than honorable discharge (formerly an "undesirable" discharge).

(2) A bad conduct discharge.

(3) In the case of separation of enlisted personnel based on administrative proceedings begun on or after October 1, 1982, uncharacterized administrative separations for:

(i) A void enlistment or induction, or

(ii) Dropped from the rolls (that is, administrative termination of military status and pay).

(f) *Offenses or events leading to discharge or release being recognized as a discharge under dishonorable conditions.* For purposes of VA's character of discharge determination under paragraph (e) of this section, a discharge or release because of one or more of the offenses or events specified in paragraph (f) of this section is a discharge or release under dishonorable conditions for VA purposes:

(1) Acceptance of an other than honorable discharge (formerly an "undesirable" discharge) to avoid trial by general court-martial.

(2) Mutiny or spying.

(3) Commission of one or more offenses involving moral turpitude. For purposes of this section, an offense involves "moral turpitude" if it is unlawful, it is willful, it is committed without justification or legal excuse, and it is an offense which a reasonable person would expect to cause harm or loss to person or property. This includes, generally, conviction of a felony.

(4) Engaging in willful and persistent misconduct during military service. A discharge because of a minor offense will not be considered willful and persistent misconduct if service was otherwise honest, faithful, and meritorious. If the misconduct includes absences without leave, see also § 5.32 (concerning mitigating factors in absence without leave cases).

(5) Sexual acts involving aggravating circumstances or other factors affecting the performance of duty. Examples of sexual acts involving aggravating circumstances or other factors affecting the performance of duty include child molestation, prostitution, sexual acts or conduct accompanied by assault or coercion, and sexual acts or conduct taking place between service members of disparate rank, grade, or status when the service member has taken advantage of his or her superior rank, grade, or status.

(Authority: 38 U.S.C. 101(2), 501, 1301)

§ 5.31 Statutory bars to VA benefits.

(a) *Purpose.* By Federal statute, commission of certain acts leading to discharge or dismissal from the Armed Forces bars the award of VA benefits (statutory bars). This section describes those acts and exceptions to the statutory bars.

(b) *Limitation to period of service concerned.* (1) *General rule.* A determination under this section that veterans benefits are statutorily barred applies only to the period of service to which the relevant discharge or dismissal applies. It does not preclude the award of benefits based upon other periods of service. *See also* § 5.37 (concerning certain cases where a service member was not discharged or released at the end of the period of time for which he or she was obligated to serve when entering a period of service because of a change in his or her military status during that period of service).

(2) *Forfeiture not precluded.* The provisions of paragraph (b)(1) of this section do not preclude forfeiture of VA benefits under 38 U.S.C. 6103, "Forfeiture for fraud," under 38 U.S.C. 6104, "Forfeiture for treason," under 38 U.S.C. 6105, "Forfeiture for subversive activities," or under similar statutes governing forfeiture of VA benefits.

(c) *Acts barring benefits.* Benefits are not payable based upon a period of service from which the service member was discharged or dismissed from the Armed Forces under one or more of the following conditions:

(1) By reason of the sentence of a general court-martial. Substitution of an administrative form of discharge for a discharge or dismissal executed in accordance with the sentence of a court-martial under 10 U.S.C. 874(b) (granting

the authority for such substitutions) does not remove this bar to VA benefits.

(2) As a conscientious objector who refused to perform military duty, wear the uniform, or comply with lawful orders of competent military authorities.

(3) As a deserter.

(4) By reason of an absence without official leave (AWOL) for a continuous period of at least 180 days. This bar is subject to § 5.32 (concerning mitigating factors in AWOL cases) and to paragraph (f) of this section (concerning limitations on the creation of overpayments). It applies to any person so discharged who was awarded a discharge under other than honorable conditions and who:

(i) Was awarded an honorable or general discharge under one of the programs listed in § 5.36(a) (concerning certain special 1970s-era discharge upgrades) prior to October 8, 1977; or

(ii) Had not otherwise established basic eligibility to receive VA benefits prior to October 8, 1977. For purposes of paragraph (c)(4)(ii) of this section, the term "established basic eligibility to receive VA benefits" means either a VA determination that an other than honorable discharge was issued under conditions other than dishonorable, or an upgraded honorable or general discharge issued prior to October 8, 1977, under criteria other than those prescribed by one of the programs listed in § 5.36. However, if a person was discharged or released by reason of the sentence of a general court-martial, only a finding of insanity (*see* § 5.33) or a decision of a board of correction of records established under 10 U.S.C. 1552 (*see* § 5.34) can establish basic eligibility to receive VA benefits.

(5) By reason of resignation by an officer for the good of the service.

(6) By reason of discharge due to alienage during a period of hostilities based on the request of a service member. However, benefits will not be barred in the absence of affirmative evidence establishing such a request.

(d) *Bars inapplicable to certain insurance.* This section does not apply to war-risk insurance, Government (converted) or National Service Life Insurance policies.

(e) *Termination of awards.* Subject to the provisions of § 3.105 of this chapter, "Revision of decisions," any award contrary to the provisions of paragraph (c) of this section will be terminated.

(f) *Limitation on creation of overpayments in AWOL cases.* Awards made after October 8, 1977, in cases in which the bar contained in paragraph (c)(4) of this section applies, will be terminated on the date of last payment.

(Authority: 38 U.S.C. 501, 5303; Pub. L. 95–126, 91 Stat. 1106, as amended by Pub. L. 102–40, 105 Stat. 239)

§ 5.32 Consideration of mitigating factors in absence without leave cases.

(a) *Compelling circumstances considered.* Separation for absence without leave (AWOL) will not preclude veteran status under § 5.30 (concerning character of discharge determinations) and will not bar benefit entitlement under § 5.31(c)(4) (concerning AWOL as a statutory bar to VA benefits) if there are compelling circumstances to warrant unauthorized absence(s).

(b) *Factors considered.* VA will evaluate all of the relevant evidence of record in determining whether there are compelling circumstances to warrant unauthorized absence(s), including consideration of the following factors:

(1) *Length of AWOL and character of service.* VA will consider the length of the period(s) of AWOL in comparison to the length and character of service exclusive of the period(s) of AWOL. Service exclusive of the period(s) of AWOL should be of such quality and length that it can be characterized as honest, faithful, meritorious, and of benefit to the nation.

(2) *Examples of circumstances VA will consider.* Reasons offered for being AWOL that VA will consider include family emergencies, compelling family obligations, or similar types of compelling obligations or duties owed to third parties. In evaluating the reasons for being AWOL, VA will consider how the situation appeared to the service member in light of the service member's age, cultural background, educational level and judgmental maturity. VA will also consider evidence showing that the service member's state of mind at the time AWOL began was adversely affected by hardship or suffering during overseas service, or by combat wounds or other service-incurred or aggravated disability.

(3) *Valid legal defense.* VA may find that compelling circumstances exist if the absence could not validly be charged as, or lead to a conviction of, an offense under the Uniform Code of Military Justice.

(Authority: 38 U.S.C. 501, 5303(a))

§ 5.33 Insanity as a defense to acts leading to a discharge or dismissal from the service that might be disqualifying for VA benefits.

If VA determines that a service member was insane at the time of the commission of an act, or acts, leading to separation from the service, the commission of such act(s) will not be a basis for denying status as a veteran under § 5.30 (concerning character of discharge determinations) or for barring the payment of VA benefits under § 5.31 (concerning statutory bars to benefits). For the definition of "insanity," *see* § 3.354.

(Authority: 38 U.S.C. 501(a), 5303(b))

§ 5.34 Effect of discharge upgrades by Armed Forces boards for the correction of military records (10 U.S.C. 1552) on eligibility for VA benefits.

(a) *Purpose.* This section describes the effect of discharge upgrades by a board established under 10 U.S.C. 1552 (board for correction of military records) on VA determinations that a service member's discharge or dismissal was under dishonorable conditions or that the service member is statutorily barred from receiving VA benefits.

(b) *Definitions.* For purposes of this section, "any applicable new determination" means a determination under § 5.30 (concerning character of discharge determinations) or § 5.31 (concerning statutory bars to VA benefits). "Applicable previous VA discharge findings" means findings by VA, based upon a previous discharge issued for the same period of service, that a service member's discharge or dismissal was under dishonorable conditions or that the service member is statutorily barred from receiving VA benefits.

(c) *Effect of discharge upgrades.* An honorable discharge, or discharge under honorable conditions, issued through a board for correction of military records is final and conclusive and is binding on VA as to characterization based on the period covered by such service. Such a discharge supersedes a previous discharge issued for the same period of service. It will be the basis for making any applicable new determination and sets aside any applicable previous VA discharge findings.

(d) *Effective date.* If entitlement to benefits is established because of the change, modification, or correction of a discharge or dismissal by a board for the correction of military records, the award of such benefits will be effective from the latest of these dates:

(1) The date of filing with the service department of the application for change, modification, or correction of the discharge or dismissal in the case of either an original claim filed with VA or a previously disallowed claim filed with VA;

(2) The date VA received a previously disallowed claim; or

(3) One year prior to the date of reopening of the previously disallowed VA claim.

(Authority: 10 U.S.C. 1552(a)(4); 38 U.S.C. 501, 5110(i))

§ 5.35 Effect of discharge upgrades by Armed Forces discharge review boards (10 U.S.C. 1553) on eligibility for VA benefits.

(a) *Purpose.* This section describes the effect of discharge upgrades by a board established under 10 U.S.C. 1553 (discharge review board) on VA determinations that a service member's discharge or dismissal was under dishonorable conditions or that the service member is statutorily barred from receiving VA benefits.

(b) *Upgrades issued before October 8, 1977.* Paragraph (b) of this section concerns the effect of an honorable or general discharge (upgraded discharge) issued by a discharge review board before October 8, 1977.

(1) *General rule.* The upgraded discharge will be the basis for making any new determination under § 5.30 (concerning character of discharge determinations) or § 5.31 (concerning statutory bars to VA benefits). The upgraded discharge will also set aside any VA findings, based upon a previous discharge issued for the same period of service, that a service member's discharge or dismissal was under dishonorable conditions or that the service member is statutorily barred from receiving VA benefits.

(2) *Exception.* The rule in paragraph (b)(1) of this section does not apply if:

(i) The previous discharge was executed by reason of the sentence of a general court-martial, or

(ii) The discharge review board was acting under the authority of one of the programs specified in § 5.36 (concerning certain special 1970s-era discharge upgrades).

(c) *Upgrades issued on or after October 8, 1977—effect on statutory bars.* Any new determinations VA makes under § 5.31 (concerning statutory bars to VA benefits) will be made without regard to an honorable or general discharge (upgraded discharge) issued by a discharge review board on or after October 8, 1977. The upgraded discharge will not set aside any VA findings, based upon a previous discharge issued for the same period of service, that a service member is statutorily barred from receiving VA benefits.

(d) *Upgrades issued on or after October 8, 1977—effect on character of discharge determinations.* (1) *General rule.* Any new determinations VA makes under § 5.30 (concerning character of discharge determinations) will be made without regard to an honorable or general discharge (upgraded discharge) issued by a discharge review board on or after October 8, 1977. The upgraded discharge will not set aside any VA findings, based upon a previous discharge issued for the same period of service, that a service member's discharge or dismissal was under dishonorable conditions.

(2) *Exceptions.* The rule in paragraph (d)(1) of this section does not apply if all of the following conditions are met:

(i) The discharge was upgraded as a result of an individual case review;

(ii) The discharge was upgraded under uniform published standards and procedures that generally apply to all persons administratively discharged or released from active service under conditions other than honorable; and

(iii) Such published standards are consistent with standards for determining honorable service historically used by the service department concerned and do not contain any provision for automatically granting or denying an upgraded discharge. VA will accept a report of the service department concerned that the discharge review board proceeding met these conditions.

(e) *Effective date.* If entitlement to benefits is established because of the change, modification, or correction of a discharge or dismissal by a discharge review board, the award of such benefits will be effective from the latest of these dates:

(1) The date of filing with the service department of the application for change, modification, or correction of the discharge or dismissal in the case of either an original claim filed with VA or a previously disallowed claim filed with VA;

(2) The date VA received a previously disallowed claim; or

(3) One year prior to the date of reopening of the previously disallowed VA claim.

(Authority: 38 U.S.C. 501, 5110(i), 5303(e))

§ 5.36 Effect of certain special discharge upgrade programs on eligibility for VA benefits.

(a) *Programs involved.* Except as provided in § 5.35(d)(2) (pertaining to discharge upgrades based on individual case review under certain published standards), an honorable or general discharge awarded by a discharge review board under one of the following programs does not remove any bar to benefits imposed under § 5.30 (concerning character of discharge determinations) or under § 5.31 (concerning statutory bars to VA benefits):

(1) The President's directive of January 19, 1977, implementing Presidential Proclamation 4313 of September 16, 1974;

(2) The Department of Defense's special discharge review program effective April 5, 1977; or

(3) Any discharge review program implemented after April 5, 1977, that does not apply to all persons administratively discharged or released from active service under other than honorable conditions.

(b) *Termination of awards.* Subject to the provisions of § 3.105 of this chapter, "Revision of decisions," any award of VA benefits made contrary to paragraph (a) of this section will be terminated.

(c) *No overpayments to be created.* No overpayments will be created as a result of payments made after October 8, 1977, based on an upgraded honorable or general discharge issued under one of the programs listed in paragraph (a) of this section which would not be awarded under the standards set forth in § 5.35(d)(2). Such payments will be terminated effective the date of last payment.

(Authority: Pub. L. 95–126, 91 Stat. 1106)

(Authority: 38 U.S.C. 5303(e))

§ 5.37 Effect of extension of service obligation due to change in military status on eligibility for VA benefits.

(a) *Purpose.* Except for persons who die in military service, status as a veteran requires that an individual be discharged or released from active military service under conditions other than dishonorable. *See* § 3.1(d) (defining "veteran"). This section describes how VA will determine whether this requirement has been met when, because of a change in his or her military status, a service member was not discharged or released at the end of the period of time for which he or she was obligated to serve when entering a period of service.

(b) *Definitions:* (1) *Change in military status.* For purposes of this section, a change in military status means a change in status that extends the period of time that a service member is obligated to serve. Examples of such a change in military status include, but are not limited to:

(i) A discharge for acceptance of an appointment as a commissioned officer or warrant officer;

(ii) Change from a Reserve commission to a Regular commission;

(iii) Change from a Regular commission to a Reserve commission;

(iv) Reenlistment; or

(v) Voluntary or involuntary extensions of a period of obligated service.

(2) *Combined periods of service.* For purposes of this section, combined

periods of service means the period of service immediately prior to the change in military status combined with the period of service immediately following the change in military status.

(c) *Combined periods of service terminating with discharge or release under honorable conditions.* VA will determine veteran status by the character of the final termination of the service member's combined periods of service if the combined periods of service terminate under honorable conditions. Otherwise, the provisions of paragraph (d) of this section apply.

(d) *Combined periods of service terminating with discharge or release under other than honorable conditions.* When a service member was not discharged or released at the end of the period of time he or she was obligated to serve when entering a period of service, he or she is eligible to receive VA benefits based upon that period of service if that service member:

(1) Completed active military service for the period of time he or she was obligated to serve at the time of entry into that period of service; and

(2) Due to an intervening change in military status was not discharged or released at the end of that period of time; but

(3) Would have been eligible for a discharge or release under conditions other than dishonorable at the end of that period of time except for the intervening change in military status.

(Authority: 38 U.S.C. 101(18))

§ 5.38 Effect of a voided enlistment on eligibility for VA benefits.

(a) *Purpose.* This section describes whether a claimant is eligible for VA benefits if the service department has voided the service member's enlistment.

(b) *Service considered valid for establishing eligibility for benefits.* A service member's enlistment that is voided by the service department for reasons other than those stated in paragraph (c) of this section is valid from the date of entry upon active duty to the date of voidance by the service department. In the case of an enlistment voided for concealment of age or misrepresentation of age, service is valid from the date of entry upon active duty to the date of discharge.

(c) *Service considered not valid for establishing eligibility for benefits.* A service member's enlistment that is voided by the service department for any of the reasons specified in paragraph (c) of this section is void from the date of entry. A service member is not eligible for VA benefits based on this period of service, if enlistment was voided for any of the following reasons:

(1) Lack of legal capacity to contract, other than on the basis of minority, such as a lack of mental capacity to contract.

(2) A statutory prohibition to enlistment, such as, but not limited to:

(i) Desertion; or

(ii) Conviction of a felony.

(Authority: 10 U.S.C. 501, 505; 38 U.S.C. 101(2), 501(a))

Minimum Service and Evidence of Service

§ 5.39 Minimum active duty service requirement for VA benefits.

(a) *Requirement.* Any individual listed in paragraph (b) of this section will not be eligible for VA benefits unless he or she has completed a minimum period of active duty described in paragraph (c) of this section upon discharge or release from service, or qualifies for an exclusion under paragraph (d) of this section.

(b) *Applicability.* The minimum active duty service requirement applies to:

(1) Any person who originally enlisted in a regular component of the Armed Forces and entered on active duty after September 7, 1980 (time spent during temporary assignment to a reserve component awaiting entrance on active duty because of a delayed entry enlistment contract does not count; this section applies if the actual date of entry on active duty is after September 7, 1980); and

(2) Any other person (enlisted or officer) who entered on active duty after October 16, 1981, who had not previously completed a continuous period of active duty of at least 24 months.

(c) *Minimum active duty service requirement.* (1) Except for veterans excluded in paragraph (d) of this section, a veteran must have served the shorter of:

(i) 24 months of continuous active duty; or

(ii) The full period of service for which the veteran was called or ordered to active duty.

(2) If it appears that the length of service requirement may not be met, VA will request a complete statement of service to determine if there are any periods of active service that are required to be excluded under paragraph (e) of this section.

(d) *Exclusions.* The minimum active duty service requirement of this section does not apply to:

(1) Any person who was discharged under an early out program described in 10 U.S.C. 1171 (Armed Forces, "Regular enlisted members: early discharge").

(2) Any person who was discharged because of a hardship as described in 10 U.S.C. 1173 (Armed Forces, "Enlisted members: discharge for hardship").

(3) Any person who was discharged or released from active duty because of a disability incurred or aggravated in line of duty,

(i) That, at the time of discharge or release, was determined to be service-connected without presumptive provisions of law, or

(ii) That person had such a disability documented in official service records at the time of discharge that, in VA's medical judgment, would have justified a discharge for the disability.

(4) Any person who has any disability that VA determines to be compensable under 38 U.S.C. chapter 11 because:

(i) VA evaluates the disability as 10 percent or more disabling according to 38 CFR part 4, "Schedule for Rating Disabilities;"

(ii) Special monthly compensation is payable for the disability; or

(iii) The disability, together with one or more other disabilities, is compensable under § 3.324 of this chapter.

(5) The provision of a benefit for or in connection with a service-connected disability, condition, or death.

(6) Insurance benefits under 38 U.S.C. chapter 19.

(e) *Temporary breaks in service.* Temporary breaks in active duty service for any of the reasons listed below will not be considered to have interrupted the "continuous service" requirement of paragraph (c)(1)(i) of this section; however, time lost due to these breaks must be subtracted from the total service time because these times do not count towards the minimum active duty service requirement:

(1) Time lost due to an industrial, agricultural, or indefinite furlough;

(2) Time lost while absent without leave;

(3) Time lost while under arrest (without acquittal or a dismissal of charges);

(4) Time lost while a deserter; or

(5) Subject to 10 U.S.C. 875(a), (concerning the restoration under certain circumstances of "all rights, privileges, and property affected by an executed part of a court-martial sentence which has been set aside or disapproved"), time lost while serving a court martial sentence.

(f) *Effect on eligibility for benefits for survivors and dependents.* (1) *General rule.* If a veteran is ineligible for VA benefits because he or she did not meet the minimum active duty service requirement, the veteran's dependents and survivors are ineligible for benefits based on that service.

(2) *Exceptions.* Paragraph (f)(1) of this section does not bar entitlement to any

of the following VA benefits to which a dependent or survivor may otherwise be entitled:

(i) Insurance benefits under 38 U.S.C. chapter 19,

(ii) Housing or small business loans under 38 U.S.C. chapter 37,

(iv) Benefits described in paragraph (d)(5) of this section,

(v) DIC based on the veteran's death in service.

(Authority: 38 U.S.C. 5303A)

§ 5.40 Service records as evidence of service and character of discharge that qualify for VA benefits.

(a) *Acceptable evidence of service.* To establish entitlement to pension, compensation, DIC or burial benefits, VA must have evidence of qualifying service and character of discharge from the service department concerned. Documents VA will accept as evidence of service and character of discharge include, but are not limited to, the following:

(1) A DD Form 214; or

(2) A Certificate of Release or Discharge from Active Duty.

(b) *Content of documents.* The document establishing service must contain information which demonstrates:

(1) The length of service;

(2) The dates of service; and

(3) The character of discharge or release.

(c) *When service department verification is not required.* VA will accept one or more documents issued by a U.S. service department as evidence of service and character of discharge without verifying their authenticity, provided that VA determines that the document is genuine and accurate. The document can be a copy of an original document if the copy:

(1) Was issued by a service department;

(2) Is certified by a public custodian of records as a true and exact copy of a document in the custodian's possession; or

(3) Is certified by an accredited agent, attorney, or service organization representative as a true and exact copy of either an original document or of a copy issued by the service department or a public custodian of records. This accredited agent, attorney, or service organization representative must have successfully completed VA-prescribed training on military records.

(d) *When service department verification is required.* VA will request verification of service from the appropriate service department if:

(1) The record does not include satisfactory evidence showing the information described in paragraph (b) of this section;

(2) The evidence of record does not meet the requirements of paragraph (c) of this section; or

(3) There is a material discrepancy in the evidence of record.

(Authority: 38 U.S.C. 501(a))

§§ 5.41–5.49 [Reserved]

[FR Doc. 04–1895 Filed 1–29–04; 8:45 am]
BILLING CODE 8320–01–P

Reader Aids

Federal Register

Vol. 69, No. 20

Friday, January 30, 2004

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.access.gpo.gov/nara**

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 (orchange 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: **info@fedreg.nara.gov**

The Federal Register staff cannot interpret specific documents or regulations.

FEDERAL REGISTER PAGES AND DATE, JANUARY

CFR PARTS AFFECTED DURING JANUARY

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.

76 2182
110 2182
490 4219
710 3213
711 3213
712 3213
Proposed Rules:
50 879
72 2528
300 4255

11 CFR

Proposed Rules:
4 2083
5 2083
11 2083
111 4092

12 CFR

7 ..... 1895, 1904
34 1904
229 1655
330 2825
1102 2500
Proposed Rules:
Ch. I 2852
Ch. II 2852
Ch. III 2852
Ch. V 2852
5 ..... 1, 892
229 1470

13 CFR

121 4057

14 CFR

1 1620
23 488
25 490
39 ..... 492, 494, 859, 861, 864, 867, 869, 871, 1503, 1504, 1505, 1507, 1509, 1511, 1513, 1515, 1516, 1519, 1521, 1657, 1659, 2059, 2062, 2655, 2656, 2657, 2659, 2661, 3000, 3233, 3629, 4057, 4231, 4232, 4234, 4448, 4450, 4452, 4454
71 ..... 495, 497, 1661, 1662, 1663, 1664, 1666, 1667, 1668, 1669, 1670, 1671, 1672, 1783, 2295, 2296, 2297, 2816, 3002, 4002
73 3003
91 1620
95 2830
97 1674
121 ..... 1620, 1840
125 1620
135 1620
255 976
1260 ..... 2831, 3235
Proposed Rules:
1 551
21 ..... 282, 551, 2970
25 551
33 551
39 ..... 282, 284, 287, 289, 291, 293, 895, 897, 900, 1274, 1275, 1547, 1549, 1551, 2855, 3036, 3039, 3041, 3043, 3533, 3535, 3859, 3861, 3863, 3865, 4255, 4257, 4259, 4261
61 2529
71 ..... 2084, 2085, 2086, 2088, 2089, 2090, 2091, 2311, 2312
73 552
91 2529
119 2529
121 ..... 282, 551, 2529, 2970
135 ..... 551, 2529, 2970
136 2529
145 2970
183 2970

15 CFR

711 2501
732 3004
738 3004
740 3004
746 3004
Proposed Rules:
740 1685
742 1685
748 1685
754 1685
772 1685

16 CFR

Proposed Rules:
Ch. I 3867
Ch. II 4095
316 4263

17 CFR

Proposed Rules:
240 ..... 2531, 4018
249 4018
270 ..... 3472, 4040
275 4040
279 4040

18 CFR

385 2503

19 CFR

Proposed Rules:
101 2092
162 2093

20 CFR

404 497
422 497
Proposed Rules:
416 554

21 CFR

1 1675
201 ..... 255, 1320
347 3005
510 1522
520 499
522 500
524 500
558 1522
610 ..... 255, 1320
1271 3823
1300 2062
1309 2062
1310 2062
Proposed Rules:
101 3868
184 2313

22 CFR

121 873

24 CFR

203 4
Proposed Rules:
990 4212
1000 2094

25 CFR

514 2504
Proposed Rules:
Ch. 1 2317

26 CFR

1 ..... 5, 12, 22, 436, 502, 1918, 3826, 4557
20 12
25 12
26 12
301 ..... 506, 4058
602 ..... 22, 436, 1918
Proposed Rules:
1 ..... 42, 43, 47, 2862
301 47

27 CFR

4 3827
5 3827
13 3827
19 3827
24 3827
25 3827
28 3827
70 3827
194 3827
252 3827

28 CFR

31 2832
33 2832
38 ..... 2298, 2832
90 2832
91 2832
93 2832
302 1524

29 CFR

102 1675
1614 3483
2590 3816
4022 2299
4044 2299
Proposed Rules:
1926 1277

30 CFR

203 3492
934 2663
Proposed Rules:
780 1036
816 1036
817 1036
935 2689

31 CFR

103 4236
363 2506

32 CFR

320 2066
806b 507, 954
1665 1524

33 CFR

17 267
100 4237
117 ..... 1525, 1918, 2508, 3835, 3836, 4237, 4239
126 4240
148 ..... 724, 3836
149 ..... 724, 3836
150 ..... 724, 3836
155 3236
165 ..... 268, 1527, 1618, 2066, 2666, 2841, 3006, 3008, 3837, 4237, 4241, 4242, 4244
334 271
Proposed Rules:
110 ..... 2095, 3869
117 ..... 1554, 1958, 2552
147 ..... 2691, 2694
151 1078
165 ..... 1556, 2318, 2320, 2554, 4267
167 3869
174 2098

36 CFR

215 1529
218 1529
223 29
Proposed Rules:
1254 295
1256 295

37 CFR

1 4059
Proposed Rules:
11 4269

38 CFR

17 1060
Proposed Rules:
5 4820

39 CFR

Proposed Rules:
3001 3268

40 CFR

9 2398
52 ..... 34, 1271, 1537, 1677, 1682, 1919, 1921, 2300, 2509, 2671, 2967, 3011, 3012, 3015, 3018, 3237, 4059, 4245
60 1786
62 ..... 2302, 2304
63 ..... 130, 394
70 ..... 2511, 3202
71 3202
82 4059
86 2398
90 ..... 1824, 2398
131 3514
180 ..... 2069, 3240, 4065, 4069, 4073
271 2674
300 ..... 1923, 2304, 2306, 4077, 4249, 4253
721 1924
1051 2398
Proposed Rules:
51 4566
52 ..... 302, 558, 1685, 2323, 2557, 2696, 3045, 3055, 4270, 4459
60 4652
62 2323
63 4652
70 2558
72 4566
75 4566

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 JANUARY 30, 2004

COMMERCE DEPARTMENT

Economic Analysis Bureau

International services surveys:

- BE-25; quarterly survey of transactions with unaffiliated foreign persons in selected services and in intangible assets; published 12-31-03
- BE-45; quarterly survey of insurance transactions by U.S. insurance companies with foreign persons; published 12-31-03

EDUCATION DEPARTMENT

Postsecondary education:

- Federal Perkins Loan Program, et al.; technical amendments; published 12-31-03

SMALL BUSINESS ADMINISTRATION

Small business size standards:

- Nonmanufacturer rule; waivers—
  - Ammunition (except small arms) manufacturing; published 1-28-04

TRANSPORTATION DEPARTMENT

National Highway Traffic Safety Administration

Motor vehicle safety standards:

- Fuel system integrity; published 12-1-03

RULES GOING INTO EFFECT JANUARY 31, 2004

TRANSPORTATION DEPARTMENT

Computer reservations systems, carrier-owned; published 1-7-04

TRANSPORTATION DEPARTMENT

Federal Aviation Administration

Air carrier certification and operations:

- Repair stations; service difficulty reporting; published 12-30-03

Aircraft:

- Repair stations; published 9-29-03

RULES GOING INTO EFFECT FEBRUARY 1, 2004

AGRICULTURE DEPARTMENT

Agricultural Marketing Service

Milk marketing orders:

- Pacific Northwest et al.; published 1-12-04

HOMELAND SECURITY DEPARTMENT

Coast Guard

Drawbridge operations:

- Florida; published 1-9-04

PENSION BENEFIT GUARANTY CORPORATION

Single-employer plans:

- Allocation of assets—
  - Interest assumptions for valuing and paying benefits; published 1-15-04

COMMENTS DUE NEXT WEEK

AGRICULTURE DEPARTMENT

Agricultural Marketing Service

Organic producers and marketers; exemption from assessments for market promotion activities; comments due by 2-2-04; published 12-30-03 [FR 03-31945]

COMMERCE DEPARTMENT

National Oceanic and Atmospheric Administration

Fishery conservation and management:

- Alaska; fisheries of Exclusive Economic Zone—
  - Gulf of Alaska groundfish; comments due by 2-2-04; published 12-2-03 [FR 03-29940]

COMMERCE DEPARTMENT

Patent and Trademark Office

Trademark cases:

- Registrations; amendment and correction requirements; comments due by 2-2-04; published 12-18-03 [FR 03-31094]

COURT SERVICES AND OFFENDER SUPERVISION AGENCY FOR THE DISTRICT OF COLUMBIA

Semi-annual agenda; Open for comments until further notice; published 12-22-03 [FR 03-25121]

ENERGY DEPARTMENT

Climate change:

- Voluntary Greenhouse Gas Reporting Program; general guidelines; comment request and public workshop; comments due by 2-3-04; published 12-5-03 [FR 03-29983]

Worker Safety and Health; chronic beryllium disease prevention programs; comments due by 2-6-04; published 12-8-03 [FR 03-30287]

ENERGY DEPARTMENT

Federal Energy Regulatory Commission

Electric rate and corporate regulation filings:

- Virginia Electric & Power Co. et al.; Open for comments until further notice; published 10-1-03 [FR 03-24818]

ENVIRONMENTAL PROTECTION AGENCY

Air programs:

- Ozone Air Quality; State and Tribal 8-hour designation recommendations
  - Agency responses; availability; comments due by 2-6-04; published 12-10-03 [FR 03-30582]

Air quality implementation plans; approval and promulgation; various States:

- Kentucky and Indiana; comments due by 2-4-04; published 1-5-04 [FR 04-00011]

Air quality planning purposes; designation of areas:

- Alabama; comments due by 2-5-04; published 1-6-04 [FR 04-00211]

Environmental statements; availability, etc.:

- Coastal nonpoint pollution control program—
  - Minnesota and Texas; Open for comments until further notice; published 10-16-03 [FR 03-26087]

Superfund program:

- Carbamates and carbamate-related hazardous waste streams and inorganic chemical manufacturing processes waste; reportable quantity adjustments; comments due by 2-2-04; published 12-4-03 [FR 03-30166]

HEALTH AND HUMAN SERVICES DEPARTMENT

Food and Drug Administration

Reports and guidance documents; availability, etc.:

- Evaluating safety of antimicrobial new animal drugs with regard to their microbiological effects on bacteria of human health concern; Open for comments until further notice; published 10-27-03 [FR 03-27113]

HOMELAND SECURITY DEPARTMENT

Coast Guard

Anchorage regulations:

- Maryland; Open for comments until further notice; published 1-14-04 [FR 04-00749]

Ports and waterways safety:

- Port Hueneme Harbor, CA; security zone; comments due by 2-4-04; published 1-5-04 [FR 04-00030]

HOMELAND SECURITY DEPARTMENT

Nonimmigrant classes:

- Aliens—
  - Special registration requirements; 30-day and annual interview requirements suspended; comments due by 2-2-04; published 12-2-03 [FR 03-30120]

United States Visitor and Immigrant Status Indicator Technology Program (US-VISIT); Biometric Requirements; implementation; comments due by 2-4-04; published 1-5-04 [FR 03-32331]

INTERIOR DEPARTMENT

Indian Affairs Bureau

Liquor and tobacco sale or distribution ordinance:

- Robinson Rancheria of Pomo Indians, CA; comments due by 2-3-04; published 12-30-03 [FR 03-32042]

INTERIOR DEPARTMENT

Land Management Bureau

Range management:

- Grazing administration—
  - Livestock grazing on public lands exclusive of Alaska; comments due by 2-6-04; published 12-8-03 [FR 03-30264]

INTERIOR DEPARTMENT

Surface Mining Reclamation and Enforcement Office

Permanent regulatory programs for non-Federal and non-Indian lands:

State program amendments; procedures and criteria for approval or disapproval; comments due by 2-2-04; published 12-3-03 [FR 03-29756]

NATIONAL AERONAUTICS AND SPACE ADMINISTRATION

Acquisition regulations:

Contractor access to confidential information; comments due by 2-3-04; published 12-5-03 [FR 03-29930]

SECURITIES AND EXCHANGE COMMISSION

Investment advisers and investment companies:

Compliance programs; comments due by 2-5-04; published 12-24-03 [FR 03-31544]

Investment companies:

Mutual fund shares; pricing rules; comments due by 2-6-04; published 12-17-03 [FR 03-31071]

Securities and investment companies:

Market timing disclosure and selective disclosure of portfolio holdings; Forms N-1A, N-3, N-4, and N-6; amendments; comments due by 2-6-04; published 12-17-03 [FR 03-31070]

Securities:

Broker-dealers; alternative net capital requirements; comments due by 2-4-04; published 11-6-03 [FR 03-27306]

Supervised investment bank holding companies; comments due by 2-4-04; published 11-6-03 [FR 03-27307]

TRANSPORTATION DEPARTMENT

Federal Aviation Administration

Airworthiness directives:

AeroSpace Technologies of Australia Pty Ltd.; comments due by 2-2-04; published 12-29-03 [FR 03-31847]

Airbus; comments due by 2-4-04; published 1-5-04 [FR 04-00051]

BAE Systems (Operations) Ltd.; comments due by 2-4-04; published 1-5-04 [FR 04-00050]

Boeing; comments due by 2-2-04; published 12-18-03 [FR 03-31180]

Dornier; comments due by 2-4-04; published 1-5-04 [FR 04-00049]

Empresa Brasileira de Aeronautica S.A. (EMBRAER); comments due by 2-4-04; published 1-5-04 [FR 04-00047]

GARMIN International Inc.; comments due by 2-3-04; published 12-30-03 [FR 03-31978]

Goodrich Avionics Systems, Inc.; comments due by 2-2-04; published 12-3-03 [FR 03-30074]

Gulfstream Aerospace LP; comments due by 2-6-04; published 1-7-04 [FR 04-00271]

Hamilton Sundstrand Corp.; comments due by 2-2-04; published 12-2-03 [FR 03-29904]

Pratt & Whitney; comments due by 2-2-04; published 12-3-03 [FR 03-30073]

Saab; comments due by 2-4-04; published 1-5-04 [FR 04-00031]

Airworthiness standards:

Special conditions—

Airbus Model A300 B4-600, -B4-600R, -F4-600R, A310-200 and -300 series airplanes; comments due by 2-5-04; published 1-6-04 [FR 04-00239]

Polskie Zaklady Lotnicze - Mielec, Model M28 05; comments due by 2-5-04; published 1-6-04 [FR 04-00240]

TRANSPORTATION DEPARTMENT

National Highway Traffic Safety Administration

Motor vehicle safety standards:

Low speed vehicles; definition; comments due by 2-6-04; published 12-8-03 [FR 03-30379]

TRANSPORTATION DEPARTMENT

Research and Special Programs Administration

Hazardous materials:

Hazardous materials transportation—

Exemptions; incorporation into regulations; comments due by 2-6-04; published 12-4-03 [FR 03-29852]

LIST OF PUBLIC LAWS

Note: A cumulative List of Public Laws for the first session of the 108th Congress appears in Part II of this issue.

Last List January 29, 2004

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.

Public Laws

108th Congress

Pamphlet prints of public laws, often referred to as slip laws, are the initial publication of Federal laws upon enactment and are printed as soon as possible after approval by the President. Legislative history references appear on each law. Subscription service includes all public laws, issued irregularly upon enactment, for the 108th Congress.

Individual laws also may be purchased from the Superintendent of Documents, U.S. Government Printing Office. Prices vary. See Reader Aids Section of the Federal Register for announcements of newly enacted laws or access the online database at http://www.access.gpo.gov/nara1/nara005.html

---

Superintendent of Documents **Subscriptions** Order Form

Order Processing Code:
*** 6216**

☐ **YES**, enter my subscription(s) as follows:

Charge your order. It's Easy!

To fax your orders (202) 512–2250
Phone your orders (202) 512–1800

_____ subscriptions to **PUBLIC LAWS** for the 108th Congress for $285 per subscription.

The total cost of my order is $ _________. **Price includes regular domestic postage and handling** and is subject to change. International customers please add 25%.

Company or personal name (Please type or print)

Additional address/attention line

Street address

City, State, ZIP code

Daytime phone including area code

Purchase order number (optional)

May we make your name/address available to other mailers? YES ☐ NO ☐

Please Choose Method of Payment:

☐ Check Payable to the Superintendent of Documents

☐ GPO Deposit Account ☐☐☐☐☐☐☐ – ☐

☐ VISA ☐ MasterCard Account

(Credit card expiration date)

Thank you for your order!

Authorizing signature

2/03

Mail To: Superintendent of Documents
P.O. Box 371954, Pittsburgh, PA 15250–7954

Printed on recycled paper